STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the application of CONSUMERS ENERGY COMPANY for authority to increase its rates for the distribution of natural gas and for other relief. / Case No. U-21806

VOLUME IV

** PUBLIC **

CROSS-EXAMINATION

Proceedings held via Microsoft Teams in the above-entitled matter before James M. Varchetti, Administrative Law Judge with MOAHR, for the Michigan Public Service Commission, Lansing, Michigan, on Monday, June 2, 2025, at 9:00 a.m.

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|---|---|---|---|
| S-12.0 | Company Response to MPSC Staff Audit Request JJH-1 | 2496 | 2496 |
| S-12.1 | Company Response to MPSC Staff Audit Request JSG-1 | 2496 | 2496 |
| S-12.2 | Company Response to Attorney General's Fifth Discovery Request U21806-AG6-CE-0499 | 2496 | 2496 |
| S-12.3 | Manufactured Gas Plant Amortization Schedule & Unamortized Balance | 2496 | 2496 |
| S-13 | CONFIDENTIAL SAP S/4HANA Implementation Project Revenue Deficiency Impact of O&M Deferral | 2487 | 2487 |
| S-14.1 | Adjustment to Projected Sales Taxes | 2635 | 2635 |
| S-14.2 | Adjustment to Projected Other General Taxes | 2635 | 2635 |
| S-15.0 | Consumers Energy's Audit Response | 2646 | 2646 |
| S-15.1 | Residential Income Assistance Credit Projection Support | 2646 | 2646 |
| S-16.1 | U-21835 Capital Expenditures, Act 9 application in MPSC Case No. U-21835 | 2668 | 2668 |
| S-16.2 | U-21854 Capital Expenditures, Act 9 application in MPSC Case No. U-21854 | 2668 | 2668 |
| S-16.3 | U-21842 Capital Expenditures, Act 9 application in MPSC Case No. U-21842 | 2668 | 2668 |
| S-17.1 | Consumers Energy's Audit Response U21806-SA-CE-319 | 2693 | 2693 |
| S-17.2 | Consumers Energy's Audit 1 Response U21806-SA-CE-318 | 2693 | 2693 |
| S-17.3 | Consumers Energy's Audit Response U21806-SA-CE-428 | 2693 | 2693 |

E X H I B I T S

| NUMBER | DESCRIPTION | OFRD | RECD |
|---|---|---|---|
| S-18.0 | Company Response to Staff Audit U21806-SA-CE-246 | 2506 | 2506 |
| S-18.1 | Investment Impact of Corrected Depreciation Rates | 2506 | 2506 |
| S-19.0 | Staff's Adjustments to IT Capital and Investment O&M by Project | 2703 | 2703 |
| S-19.1 | Company Audit Responses | 2703 | 2703 |
| S-19.2 | CONFIDENTIAL Company Discovery Response | 2703 | 2703 |
| S-20.1 | Other Employee Benefits Expense for the Test Year Ending October 31, 2026 | 2720 | 2720 |
| S-20.2 | Other Employee Benefits Leave It Better Award for the Test Year Ending October 31, 2026 | 2720 | 2720 |
| S-21.0 | FERC Account 378 Composite Allocator Calculation | 2748 | 2748 |
| S-22.0 | Staff Adjustments to Capital Expenditures to Material Condition non-modeled program and Compliance and Controls program | 2727 | 2727 |
| S-22.1 | Consumers Energy's Response to Staff Audit Request U21806-SA16 CE-389 | 2727 | 2727 |
| S-22.2 | Consumers Energy's Response to Staff Audit Request U21806-SA20 CE-420 | 2727 | 2727 |
| S-22.3 | Consumers Energy's Response to the Attorney General's Discovery Request U21806-AG-CE-0422 | 2727 | 2727 |
| S-22.4 | Consumers Energy's Response to Staff Audit Request U21806-SA6 CE-421 | 2727 | 2727 |
| S-23 | Audit Response U21806-SA-CE-035 | 2741 | 2741 |
| S-24 | November 2025 - October 2026 Test Year Gas Cost-of-Service Study Total Annual Sales and Peak Month Sales | 2563 | 2563 |
| S-25 | ABATE's Response to Staff's First Discovery Request | 2775 | 2775 |

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Monday, June 2, 2025

9:00 AM Eastern

- - -

(Hearing resumes following adjournment of Friday, May 30, 2025)

JUDGE VARCHETTI: Good morning, everyone. We are now on the record in Case U-21806 captioned in the matter of the application of Consumers Energy Company for authority to increase its rates for the distribution of natural gas and for other relief.

Today is the date and time scheduled for a third day of cross-examination in this case. My name is James Varchetti. I'm the ALJ that has been assigned to be the presiding officer in this matter, and for the record, I'll note that today's hearing is being held via video conference on the Microsoft Teams platform.

I'd like to start today by asking the attorneys present to place their appearances on the record, starting with counsel for the utility.

MS. UITVLUGT: Good morning, Your Honor. Anne Uitvlugt appearing on behalf of Consumers Energy Company. I'd also like to enter the appearance of Bret Totoraitis, Gary Gensch, Spencer Sattler, Evan Keimach, and Mark Ruszkiewicz.

JUDGE VARCHETTI: Thank you. And good

morning.

Next, who is appearing today on behalf of the Commission Staff?

MS. STIRLING: Good morning, Your Honor. Anna Stirling on behalf of the Michigan Public Service Commission Staff. Also appearing in this matter are Amit Singh, Alena Clark, and Michael Orris.

JUDGE VARCHETTI: Thank you. And good morning, all.

Next, who is appearing today on behalf of the Attorney General?

MS. GILL: Good morning, Your Honor. Celeste Gill on behalf of Attorney General Dana Nessel.

JUDGE VARCHETTI: Thank you. And good morning.

Next, who is appearing today on behalf of the Michigan Environmental Council and Sierra Club?

MR. BZDOK: Good morning, Your Honor. We have a few appearances for the mix of parties that include the Michigan Environmental Council, Sierra Club, and Citizens Utility Board of Michigan.

I will first enter my appearance. Christopher Bzdok on behalf of Michigan Environmental Council and Sierra Club. And then I will refer to Mr. Shrinath, if I may.

JUDGE VARCHETTI: Certainly.

MR. SHRINATH: Nihal Shrinath on behalf of Sierra Club, and I'm joined by Thomas Phillips as well.

JUDGE VARCHETTI: Thank you. And who's appearing today on behalf of the Citizens Utility Board?

MS. HILLYER: Good morning, Your Honor. Holly Hillyer appearing on behalf of the Citizens Utility Board of Michigan and also the Michigan Environmental Council.

JUDGE VARCHETTI: Thank you. And good morning.

And who is appearing today on behalf of the Association of Businesses Advocating Tariff Equity?

MR. CAMPBELL: Good morning, Your Honor. Steve Campbell, Clark Hill, PLC, on behalf of the Association of Businesses Advocating Tariff Equity.

JUDGE VARCHETTI: Thank you. And good morning.

And who is appearing today on behalf of the Lansing Board of Water of Light and Michigan State University?

MR. LUSSIER: Good morning, Your Honor, Cole Lussier appearing on behalf of Michigan State University and the Lansing Board of Water and Light.

JUDGE VARCHETTI: Thank you. And good

morning.

All right. Are there any other appearances or is there any attorney present that I missed?

I am looking around, and I am not seeing anyone, so I believe that everyone has made their appearance.

All right. So good morning, everyone. As we said, this is the third day of cross-examination in this case. My understanding is there is just one witness to cross-examine, and then after that, we can continue with binding in testimony from other parties.

So that being said, I would like to begin. So, Ms. Uitvlugt, if you would please call the witness, and we can have him sworn in.

MS. UITVLUGT: Yes, Your Honor. At this time, the Company calls Neal P. Dreisig to the stand.

THE REPORTER: Would you raise your right hand, please.

Do you solemnly swear the testimony you will give in this matter will be the truth, the whole truth, and nothing but the truth, so help you God?

MR. DREISIG: Yes.

JUDGE VARCHETTI: All right. You can proceed.

MS. UITVLUGT: Thank you, Your Honor.

NEAL P. DREISIG,

HAVING BEEN CALLED BY THE COMPANY AND SWORN:

DIRECT EXAMINATION

BY MS. UITVLUGT:

Q. Good morning, Mr. Dreisig. Can you please state your full name and business address for the record.

A. My full name is Neal Patrick Dreisig. Business address is 1945 West Parnall Street in Jackson, Michigan.

Q. And who are you employed by?

A. Consumers Energy Company.

Q. And what is your role at the Company?

A. I am the executive director of gas strategy and projects.

Q. And did you cause to be prefiled in this matter the direct testimony of Neal P. Dreisig, which consists of a cover page and seven pages of questions and answers?

A. Yes.

Q. Did you also cause to be prefiled in this matter the rebuttal testimony of Neal P. Dreisig, which consists of a cover page and 12 pages of questions and answers?

A. Yes.

Q. Do you have any changes you wish to make to either your rebuttal or direct testimony?

A. No.

Q. And if I were to ask you those questions today, would your

answers be the same?
A. Yes.
Q. And are you adopting this as your sworn testimony in this case?
A. Yes.
Q. And did you also cause to be prefiled in this matter a couple of exhibits?
A. Yes.
Q. And is that Exhibit A-42 and Exhibit A-133? And I would note that there is both a redacted and a confidential version of Exhibit A-133.
A. Yes.
Q. Do you have any changes you wish to make to either of those exhibits?
A. No.
Q. And were those exhibits prepared by you or at your direction?
A. Yes.

MS. UITVLUGT: Thank you. Your Honor, at this time, I would ask that the direct and rebuttal testimony of Mr. Dreisig be bound into the record, and I would move for the admission of his exhibits at the end of cross-examination, and I would tender the witness for cross.

JUDGE VARCHETTI: Thank you. Are there

any objections at this time to the binding in of Mr. Dreisig's direct or rebuttal testimony?

Hearing none, the direct and rebuttal testimony of Mr. Dreisig is bound into the record.

(Direct and Rebuttal Testimony bound in)

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

| | | |
|---|---|---|
| In the matter of the application of<br>**CONSUMERS ENERGY COMPANY**<br>for authority to increase its rates for the<br>distribution of natural gas and for other relief. | )<br>)<br>)<br>)<br>) | Case No. U-21806 |

**DIRECT TESTIMONY**

**OF**

**NEAL P. DREISIG**

**ON BEHALF OF**

**CONSUMERS ENERGY COMPANY**

December 2024

**Q. Please state your name and business address.**

A. My name is Neal P. Dreisig, and my business address is 1945 West Parnall Road, Jackson, Michigan 49201.

**Q. By whom are you employed?**

A. I am employed by Consumers Energy Company ("Consumers Energy" or the "Company").

**Q. What is your position with Consumers Energy?**

A. I am the Executive Director of Gas Strategy in the Gas Engineering and Supply organization, a position I have held since July 2024.

**Q. What are your responsibilities as Executive Director of Gas Strategy?**

A. As Executive Director, I am responsible to lead the overall long term strategy of the regulated gas business at the Company. This includes long term plans for transmission, storage, compression, distribution, and decarbonization. This also includes the development, recommendation, and administration of the Natural Gas Delivery Plan ("NGDP").

**Q. What is your educational background?**

A. I graduated from the Michigan State University with a Bachelor of Science in Construction Management in 2006. Additionally, in 2019, I earned a Master of Science degree in Management with a concentration in Finance from Colorado State University.

**Q. Do you have any professional certifications?**

A. Yes, I have received a Project Management Professional certification from the Project Management Institute in 2011.

**Q. What is your work experience?**

A. In addition to my current role, I previously held the position of Senior Strategy Manager, responsible for the cross-functional research, analysis, and oversight of decarbonization

related assets. I previously held the Manager of Cost Engineering position in the Enterprise Project Management Department for three years. In that role, I had responsibility for the financial predictability of capital forecasting, estimate refinement, and spending efficiency, approximately $1 billion in capital, annually. I have also served the Company as a cost engineer and generation outage planner. In these roles, I assisted in capital project development, planning, and predictable execution. Prior to this, I worked as a construction engineer on large industrial and automotive projects.

**Q. Have you previously testified before the Michigan Public Service Commission ("MPSC" or the "Commission")?**

A. Yes, I have previously provided testimony in Case No. U-20893, the Company's Investment Recovery Mechanism Reconciliation; in Case No. U-21141, the Company's Voluntary Carbon Offset Program; Case No. U-21148, the Company's General Gas Rate Case; Case No. U-21308, the Company's General Gas Rate Case; and in Case No. U-21490, the Company's General Gas Rate Case.

**Q. What is the purpose of your direct testimony?**

A. The purpose of my direct testimony is to provide an overview of the Company's natural gas transmission, distribution, storage, and compression systems, and an updated version of the Company's 10-year plan called the *Natural Gas Delivery Plan* per Exhibit A-42 (NPD-1).

**Q. Are you sponsoring any exhibits?**

A. Yes. I am sponsoring the following exhibits:

| | |
|---|---|
| Exhibit A-42 (NPD-1) | Natural Gas Delivery Plan |

**Q. Were these exhibits prepared by you or under your direction and supervision?**

A. Yes.

**Q. What is the purpose of the NGDP?**

A. The NGDP was developed to provide a transparent investment plan for the next decade for the Company's natural gas assets. This investment plan framework considers safe and reliable gas supply, how the Company plans to evolve its assets in accordance with the Gas Pipeline industry standard American Petroleum Institute Recommended Practice 1173 Pipeline Safety Management Systems framework, and to develop a strategic framework in response to decarbonization goals of the Company's natural gas customers and future carbon policy relevant to the utility. The Company's most recent update to the NGDP is included in this rate case as Exhibit A-42 (NPD-1). Over the last five years, Consumers Energy has prudently invested over $4.7 billion in its gas system for safety, reliability, deliverability, system integrity, and customer service through the NGDP.

**Q. Can you describe Consumers Energy's natural gas system?**

A. Yes. Consumers Energy's natural gas system contains 2,342 miles of transmission pipelines, more than 28,368 miles of distribution mains, and approximately 1.8 million services. The Company operates seven compressor stations on the transmission system, one compressor station on the distribution system, and has 15 underground storage fields. Consumers Energy receives natural gas supply into its transmission system with varying maximum allowable operating pressures. Consumers Energy's transmission system provides reliable supply to its customers by using compressor stations to bring natural gas onto its transmission system and to leverage storage to balance supply with customer demand. The transmission system supplies natural gas to city gates, which deliver gas to the distribution system. The Company's distribution system moves gas from city gates

through pressure regulation stations into neighborhoods and commercial and industrial districts to customer homes and businesses.

**Q. Were there external drivers considered by the Company that shape the NGDP?**

A. Yes. The main external drivers that inform the NGDP are the following:

1. **Safety** – Employees, customers, and the public must safely co-exist with natural gas assets. The Company must anticipate risks and mitigate them proactively.

2. **Increasing Regulation** – Major incidents across the nation's natural gas infrastructure and changing policies regarding carbon and methane emissions continue to introduce new requirements at the state and federal levels.

3. **Changing Supply and Demand Patterns** – NGDP proactively manages natural gas supply to mitigate price volatility while ensuring current and future demand is met.

4. **Environmental Focus** – The natural gas system can contribute greenhouse gas emissions to the atmosphere in the form of carbon dioxide and methane emissions. Customers, regulators, and policymakers at the State and Federal level have expressed interest in how the Company will reduce emissions and how the Company can help customers reduce emissions.

**Q. What are the main objectives for the NGDP?**

A. The NGDP has four main objectives. These are:

1. **Safe** – Safety remains Consumers Energy's top priority seeking to reduce the probability of incidents that could adversely affect public safety, customers, and employees. This means:

   - Continuously reducing system risk;

   - Modernizing distribution and transmission assets through inspection and replacement of vintage materials in mains and services. Examples of this include vintage main replacements, vintage service replacements, pipeline integrity, Well Logging and Rehabilitation Program, and TED-I projects; and

   - Emphasizing implementation of best practices in Gas Safety Management Systems and records management, and continued use of operational metrics to measure the safety of the Company's personnel, physical and digital assets, and processes.

2. **Reliable** – Consumers Energy is committed to a reliable and resilient system, measured through metrics such as gas flow deliverability to avoid unplanned outages. Consumers Energy views resiliency as the gas system's ability to prevent, withstand, adapt to, and quickly recover from a high-impact, low-likelihood event and essential for safe and continuous customer service. The Company continues to evaluate the balance between system reliability, resilience, and optimization by improving asset reliability.

3. **Affordable** – Consumers Energy's planned system investments including those in technology and automation improve safety and reliability, which can be made while maintaining stable, predictable, and reasonable growth in total bills. These investments will are a small percentage of household spending and provide a highly valuable product that is safe, reliable, and improves quality of life.

4. **Clean** – The Company is committed to reducing greenhouse gas emissions across its systems associated with the energy consumption of its customers. In support of Michigan's MI Healthy Climate Plan along with Federal executive orders and policies, Consumers Energy continues to lead Michigan's clean energy transformation to help customers and suppliers reduce their greenhouse gas emissions. The Company is executing on this commitment in the following key actions:

    - **Reducing Fugitive Emissions**: In 2019, the Company committed to reducing methane emissions from the natural gas delivery system by 80% by 2030;

    - **Customer Programs**: In 2024, the Company received approval for a voluntary program for natural gas customers to offset carbon emissions associated with natural gas use through renewable natural gas. Accordingly, renewable natural gas projects will accompany Michigan forest preservation efforts as part of the MI Clean Air Program.

Please refer to the NGDP, Exhibit A-42 (NPD-1), for further elaboration on the Company's efforts to improve its performance in these areas along with the testimony and exhibits of Company witness Lincoln D. Warriner for distribution capital; Company witness Timothy K. Joyce for compression and storage capital; Company witness Kristine A. Pascarello for material condition distribution capital, advanced methane detection, and engineering operations and maintenance; Company witness Michael P. Griffin for transmission capital

and pipeline integrity; and Company witness James P. Pnacek for operating and maintenance expenses for the Company's Gas Operations.

**Q. Does the NGDP discuss operational capabilities needed for successful execution of the NGDP?**

A. Yes. As Consumers Energy moves forward with the NGDP, there are intentional actions by the Company in the operational capabilities of people, process, and technology for each of the asset areas to enable the 10-year objectives, goals, and outcomes to be successfully achieved. As described in the NGDP, Exhibit A-42 (NPD-1), technology (i.e., information technology) or digital projects enable the expected NGDP future outcomes. Company witness Stacy H. Baker includes in her direct testimony technology projects that are critical in supporting gas functions including gas Supervisory Control and Data Acquisition software, the probabilistic risk model project, and the gas transmission, distribution and compression historians.

**Q. Are there any new additions to the NGDP?**

A. Yes. The Company included a section associated with energy and environmental justice ("EEJ"). The Company is committed to delivering safe, reliable, clean, and low cost energy to all customers for an equitable future. Recently, the Michigan Public Service Commission and other parties have expressed interest in EEJ. EEJ broadly relates to a holistic view of energy equity, community benefits and impacts on disproportionately impacted communities within the Company's gas service territory. The Company routinely engages communities in its service territory and has a long-standing history of upholding these communities.

**Q. How are EEJ communities defined?**

A. The MiEJScreen tool, operated by Michigan Department of Environment, Great Lakes, and Energy ("EGLE"), will be used to identify the highest impacted areas within the Company's service territory. Regions with scores of 80+ are defined as EEJ communities. Currently, there are approximately 150,000 customers that reside in EEJ communities within the Company's gas service territory. The Company is seeking to better understand factors including vintage materials and vintage systems in these areas to ensure equitable progress is made in replacing these materials.

**Q. Will all of the projects in NGDP support the objectives of Safe, Reliable, Affordable and Clean?**

A. Yes. As described in the NGDP, Exhibit A-42 (NPD-1), fully funding both the capital and operating and maintenance costs for the NGDP projects and executing the projects, will position the Company to achieve safe, reliable, predictable, prudent, and affordable outcomes throughout the next 10 years.

**Q. Does this conclude your direct testimony?**

A. Yes.

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

| | | |
|---|---|---|
| In the matter of the application of<br>**CONSUMERS ENERGY COMPANY**<br>for authority to increase its rates for the<br>distribution of natural gas and for other relief. | )<br>)<br>)<br>)<br>) | Case No. U-21806 |

# REBUTTAL TESTIMONY

# OF

# NEAL P. DREISIG

# ON BEHALF OF

# CONSUMERS ENERGY COMPANY

May 2025

**Q. Please state your name and business address.**

A. My name is Neal P. Dreisig, and my business address is 1945 West Parnall Road, Jackson, Michigan 49201.

**Q. Are you the same Neal P. Dreisig who previously submitted testimony in this case?**

A. Yes.

**Q. What is the purpose of your rebuttal testimony?**

A. The purpose of my testimony is to rebut testimony associated with concerns on the Natural Gas Delivery Plan ("NGDP") by Attorney General witness Sebastian Coppola, Michigan Environmental Council ("MEC") and Sierra Club ("SC") (collectively, MEC) witnesses Alice Napoleon and Dr. Sol deLeon, Citizens Utility Board of Michigan ("CUB") witnesses Richard J. Bunch and Joshua W. Denzler.

**Q. Are you sponsoring any exhibits with your rebuttal testimony?**

A. Yes, the following exhibit is sponsored with my rebuttal testimony:

| | |
|---|---|
| Exhibit A-133 (NPD-2) Confidential | Discovery Responses U21806-MNSC-CE-0039, 0066, 0573, and 0771 with Attachments. |

**Q. Were these exhibits prepared by you or under your supervision?**

A. Yes.

## I. ATTORNEY GENERAL WITNESS COPOLLA

**Q. On page 14, lines 18 through 20, of his direct testimony, Attorney General witness Coppola states that the Company is investing in the gas system as an opportunity to accelerate rate base growth to increase earnings growth. Is this accurate?**

A. No, it is not. The Company's investments and the focus of the NGDP, Exhibit A-42 (NPD-1), are founded on the Company's commitment to providing a safe, reliable, affordable, and clean natural gas system for the people of Michigan. The capital

investments are made by the Company to ensure safety and reliability for its natural gas customers and to prevent incidents like those experienced by other operators in recent years. The NGDP, and the Company's investments, were developed by the Company's engineers. Planned work undertaken in gas distribution, transmission, compression, and storage are discussed in my direct testimony and in the direct testimony of Company witnesses Timothy K. Joyce, Kristine A. Pascarello, Lincoln D. Warriner, James P. Pnacek, and Michael P. Griffin. The comprehensive NGDP discusses the investments the Company is making, the reasons for the investments, the benefits of these investments, and considers the cost of these investments to customers.

**Q. On page 15, lines 14 through 18, of his direct testimony, Attorney General witness Coppola states that the gas utility forecasts to spend $20 billion in capital over the next five years. Is this accurate?**

A. No. As shown in Exhibit A-42 (NPD-1), the proposed five-year plan shows approximately $5.5 billion in proposed capital spending, not $20 billion.

**Q. On pages 16 and 17, lines 4 through 9 and 2 through 10, respectively, of his direct testimony, Attorney General witness Coppola states that capital spending will pose a significant burden on residential customers and business bills. Is this accurate?**

A. No. As discussed in Exhibit A-42 (NPD-1), the Company is committed to a bill growth rate at or below inflation and below the average rate of other gas utilities in the Midwest. Despite a historical 12% increase in rate base over the past 10 years, as described by Mr. Coppola, customer bills have shown a continuous annual growth rate ("CAGR") of -0.60%, which shows bills have actually decreased over the same period. Note, this is well

below Consumer Price Index of 2.80%[1] over the same period. When adjusted for inflation, customer bills decreased in real terms by approximately 4% per year compared to other goods and services making it a smaller component of a household's overall spend. In fact, data shows the average residential gas bill is approximately 1% of Michigan household income, considerably below other necessities such as transportation and cellular communication, 15% and 2%, respectively.[2] It is important to note that an increase in rate base does not necessarily correlate to an increase in bills as demonstrated above. Furthermore, the Company is committed to helping customers use less natural gas through energy efficient solutions and helping low-income customers through the Consumers Affordable Resource of Energy ("CARE") Program. These programs are discussed by Company witness Byrom.

**Q. How does the Company's residential bill affordability compare to gas utility peers in the Midwest?**

A. The Company benchmarks residential bills against Midwest gas utilities who experience similar climate conditions. Over the past five years, the Company has maintained a monthly residential bill below the Midwest average by approximately 24%. Additionally, the rate of bill growth is also below the Midwest average. Specifically, over the past five years, the Company's residential bills grew 1.4% less than the Midwest average. This is due in part to the Company's storage capabilities where natural gas can be purchased in

[1] U.S. Bureau of Labor Statistics. (2024). Consumer Price Index Summary. Retrieved from https://www.bls.gov/regions/midwest/data/consumerpriceindexhistorical_detroit_table.pdf.
[2] US Wages & Salaries and Expenditures. (2023). Retrieved from https://www.bls.gov/cex/tables/calendar-year/mean-item-share-average-standard-error.htm
Michigan Income Fred St. Louis. (2023). Retrieved from https://fred.stlouisfed.org/series/MEHOINUSMIA672N

the summer at a lower rate, stored, and then sold to customers in the winter at the same price.

## II. CUB WITNESS BUNCH

**Q. On page 6 of his direct testimony, CUB witness Bunch asserts that the proposed 12% rate increase is much higher than expected inflation. Is this accurate?**

A. No. The proper comparison to inflation is the actual rate per mcf customers pay on their bill. Over the past 10 years, the Company's residential rate per mcf shows a CAGR of 1.38%, well below the rate of inflation over the same period at 2.80%.[3] As described above, when adjusted for inflation, residential customers saved on their natural gas bill compared to other goods and services included in the Consumers Price Index.

**Q. On page 9, lines 6 through 10, of his direct testimony, CUB witness Bunch asserts that the proposed spending plan would severely impact residential rates, driving them by 158%. Is this accurate?**

A. No. As shown in the Natural Gas Delivery Plan over the next 10 years, the Company expects an approximate 4.7% CAGR in residential bills, which is approximately the rate of inflation over the past five years. This projected increase equates to a cumulative 67% increase, not 158%. Additionally, increases assume relatively flat natural gas load over the next 10 years. Given the projected energy increases in the future, increased natural gas use in power generation and industrial development will potentially offset bill increases to a certain extent.

[3] U.S. Bureau of Labor Statistics. (2024). Consumer Price Index Summary. Retrieved from https://www.bls.gov/regions/midwest/data/consumerpriceindexhistorical_detroit_table.pdf.

## III. MEC WITNESS DENZLER

**Q. On pages 4 and 5, lines 6 through 13 and 11 through 18, respectively, of his direct testimony, MEC witness Denzler asserts that the proposed spending plan would severely impact residential rates, driving them by 158% and will be "super-inflationary." Is this accurate?**

A. No, it is not. See my response to CUB witness Bunch on in Section II.

**Q. On page 6, lines 3 through 14, of his direct testimony, MEC witness Denzler asserts that natural gas demand is not certain, leading to stranded costs in the future. Is this accurate?**

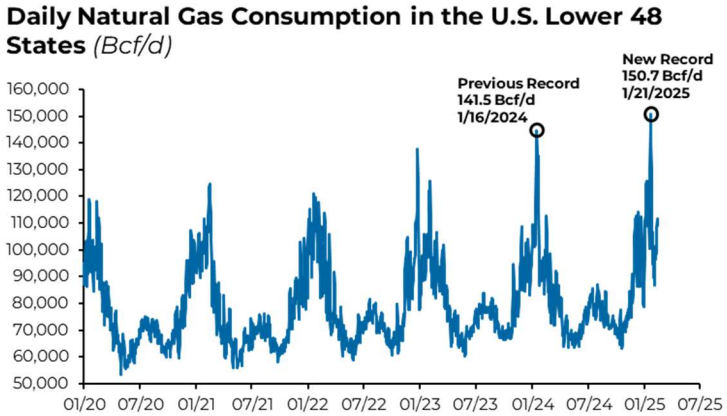
A. No, it is not. Data shows that the natural gas system is critical to Michigan's energy future from a low cost, customer, and energy capacity perspective. Regarding low-cost, natural gas is by far the least cost energy source for Michigan. The table below demonstrates this by comparing various energy costs on a $/MMbtu basis using the recent Company gas residential rates, Michigan average electric residential rates, and Michigan propane rates. For example, using the recent Michigan average electric rate of $0.1921/KWh, the conversion to MMbtu would equate to $56.30/MMbtu, showing over a 5x increase in commodity cost versus natural gas. It is clear all other fuels are considerably more expensive than natural gas.

| | $/Mmbtu |
|---|---|
| CE Natural gas | $10.30 |
| Propane | $25.36 |
| MI Electric rate | $56.30 |

From a customer perspective, when asking gas customers "how do you feel Consumers Energy should prioritize each of the following as they plan for the future?"

with the ability to rank the options of "reliability," "affordability," and "sustainability," 48.9% rated reliability as a first priority for the Company. 41.2% of gas customers ranked affordability as a second priority, with 35% ranking affordability as the first priority. This tells us that natural gas is preferred as an exceptionally reliable and affordable energy source that will not only remain stable in the future but enable quality of life supported by low cost natural gas.

Lastly, the natural gas infrastructure provides significant energy capacity for Michigan. Recent climate trends, shown below, continue to set natural gas daily consumption records when cold snaps occur. During these peak conditions, the combination of space heating demand with lower output from renewables during winter months allow natural gas generators to fill demand. These spikes in demand highlight the critical importance of gas system capacity in delivering heat on the coldest days and fuel for potential future gas generation.



## IV. MEC WITNESS DELEON

**Q. On pages 10 and 11, lines 19 through 23 and 1 through 4, respectively, of her direct testimony, MEC witness deLeon asserts that natural gas assets will become stranded due to the energy transition. Is this accurate?**

A. No. In addition to the responses above to CUB witness Bunch, analysis shows the gas system infrastructure will become more critical from the perspective of the energy transition. As described in Exhibit A-133 (NPD-2) Confidential, which is a packet of discovery response that the Company provided to MEC which includes discovery response U21806-MNSC-CE-0066, the retirement of coal generation and high cost of nuclear indicates natural gas will likely serve as a reliable, low-cost, baseload fuel for the significant growth in future energy demand through gas generation. Additionally, the gas distribution system enables cost effective heating that mitigates an otherwise 40% additional electric load for winter heating if end uses were electrified. Accordingly, gas distribution reduces the need for investment in electric generation and infrastructure by ~$20-25 billion.

**Q. On page 14 of her direct testimony, MEC witness deLeon questions the effectiveness of the Renewable Natural Gas ("RNG") Program to contribute to the Company's greenhouse gas emission reduction goal. Is this a concern?**

A. No. Customers have shown significant interest in the Company's RNG product, concentrated in the large industrial space. With most customer voluntary goals around the 2030 timeframe, customers have indicated they do not want a natural gas decarbonization solution until they need it, further emphasizing customer's priority around cost. Total expressed interest well exceeds the Company's available production emphasizing the need

to potentially expand the Program in the future. Customers show high interest in RNG because it is the least cost clean fuel alternative to natural gas, it is considered "drop-in" meaning no infrastructure modifications are required, the feedstock is readily available in Michigan, and it strongly supports the agricultural industry. Customer data aligns with the MI Healthy Climate Plan presumption that clean fuel alternatives like RNG are critical in decarbonizing high heat end uses.

**Q. On page 17 of her direct testimony, MEC witness deLeon indicates the NGDP shows no evidence that the Company is pursuing non-pipe alternatives to meet its customer emission reduction goal. Is this true?**

A. No. As described in the NGDP, the Company is actively investigating all potential carbon reduction pathways to meet the needs of customers in the future with an established framework. As demonstrated in Exhibit A-133 (NPD-2) Confidential, which is a packet of discovery response that the Company provided to MEC which includes discovery response U21806-MNSC-CE-0063 and U21806-MNSC-CE-0771, this framework includes maintaining a marginal cost abatement curve and long term modeling for a decarbonized future. The Company extensively collaborates with stakeholders around the industry to inform and validate modeling and analysis assumptions. Collaborations include other domestic and global peer utilities, the Low Carbon Resources Initiative, the H2EDGE Program, the MI Hydrogen Initiative, and the Midwest Alliance for Clean Hydrogen ("MachH2") hydrogen hub as an energy provider These collaborations are evident in the Company's work in network geothermal technology supported by the associated grant received from the Michigan Public Service Commission ("MPSC" or the "Commission"), along with the industry grant received to study synthetic gas production in Michigan using

green hydrogen. It is well understood through these collaborations that non-pipe alternatives that involve introducing new technologies raise cost for customers, and in some cases jeopardize the safety of the gas system. For these reasons, meeting customers' current and future needs is core to the NGDP. As described above, customers are most interested in reliable, low-cost energy, not more expensive non-pipe alternatives.

## V. MEC WITNESS NAPOLEON

**Q. On page 10, lines 10 through 13, MEC witness Napoleon indicates the decarbonization study by the Company is inconsistent with other studies performed. Is this true?**

A. No. The Low Carbon Resource Initiative net-zero 2050 study, performed by the Electric Power Research Institute ("EPRI"), was used to test outputs of the Company led study, showing similar findings. Specifically, EPRI found that "Optionality enables affordability. Achieving economy-wide net-zero CO2 emissions while maintaining reliable delivery of energy and energy services across the economy will require a broad set of low-carbon technologies. An economy-wide, net-zero target with the flexibility to allocate positive and negative CO2 emissions allows each sector and region to follow their own decarbonization path while minimizing overall costs. Imposing greater limitations on resource and technology options could significantly increase the overall cost to achieve net zero emissions." This finding aligns with the Company's own study concluding that the balanced combination of multiple technologies such as energy waste reduction ("EWR"), RNG, carbon capture, hydrogen, and electrification will all be needed to cost effectively meet the State's 2050 net zero goal. The MI Healthy Climate Plan also supports the findings of the Company's decarbonization study demonstrating that no one pathway is viable to achieving the State's 2050 net zero ambitions. Additionally, the Company

performed the decarbonization study from an energy agnostic standpoint to truly understand the most effective way Michigan can decarbonize energy use. It was not in any way bias towards natural gas.

**Q. On page 15 and 16, MEC witness Napoleon claims electrification can save costs by avoiding traditional infrastructure investments. Is this true?**

A. No. The economics of electrification are based on the combination of technology capital costs, costs of energy, and technology efficiencies specific to geographic regions. The components are not mutually exclusive. As described above, if all customers electrified space heating, they would not only be impacted by an energy source 5x more costly than natural gas but also impacted by the cost of electric infrastructure buildout, estimated between $20-$25 billion. While forms of electrification can be highly energy efficient, they also have high upfront costs. Efficiency gains from electrification cannot make up for the up-front cost and disparity in energy cost. Regarding efficiency, electrified space heating efficiency drops considerably and consumes more energy in colder climates like Michigan, requiring supplemental heating. The Company agrees with Ms. Napoleon that energy efficiency and electrification go hand in hand. It is not practical to assume a heat pump can provide sufficient space heating without proper insulation. In fact, according to the American Community Survey, the median residential home in Michigan is 51 years old, up 4 years since 2014, indicating that homes are getting older. Older homes often do not carry sufficient insulation to take advantage of heat pump efficiencies. Additionally, as shown in Exhibit A-133 (NPD-2) Confidential, which is a packet of discovery response that the Company provided to MEC which includes discovery response U21806-MNSC-CE-0039 and U21806-MNSC-CE-0573, independent third party studies that conclude

reality for electrification in Michigan citing it is likely not cost effective due to climate and building retrofits required to realize benefits.

**Q. On page 17, MEC witness Napoleon claims the Company is not assessing non-pipe alternatives. Is this true?**

A. No. See my response above to MEC witness deLeon.

**Q. On page 17, MEC witness Napoleon claims all non-pipe alternatives reduce emissions. Is this true?**

A. No. It is industry standard to quantify emissions using lifecycle assessment measured in grams of carbon dioxide equivalent per megajoule ("gCO2e/MJ"). This measurement is called carbon intensity ("CI"). Natural gas shows an approximate CI of 80. Any fuel source below 80 is considered low carbon and contributes to emission reduction. On the contrary, any fuel above 80 increases emissions. Electrification and hydrogen technologies powered by the electric grid carry the emissions profile of the electric grid. According to real-time electricity maps at the time of this writing[4], the Midwest Independent System Operator, Inc. ("MISO") has a CI of 110, nearly 40% higher than conventional natural gas. This indicates that technologies powered by the electric grid like heat pumps and hydrogen electrolyzers actually emit more carbon than heating with natural gas today.

**Q. On pages 25 and 26 of her direct testimony, MEC witness Napoleon claims gas consumption will decline in the future due to trends in electrification. Is this true?**

A. No. As described by Company witness Warriner in his rebuttal testimony, trends in gas growth exceed electrification. Additionally, as described above, the cost of electrification

[4] Electricity Maps. (2025). Retrieved from Live 24/7 $CO_2$ emissions of electricity consumption | App | Electricity Maps.

in many cases for customers is considerably higher than natural gas. For this reason, the practicality of electrification in Michigan is limited.

**Q. Does this conclude your rebuttal testimony?**

A. Yes.

JUDGE VARCHETTI: That being said, the witness has been tendered for cross, so Mr. Shrinath or Mr. Bzdok, whichever one of you is starting, please proceed.

MR. SHRINATH: Thank you, Your Honor.

CROSS-EXAMINATION

BY MR. SHRINATH:

Q. Good morning, Mr. Dreisig. Good to see you again. How are you?

A. Doing well, thank you.

Q. Are you able to access the folder with your name on it in the MEC/Sierra Club/CUB folder on Sharepoint?

A. Yes.

Q. Great. And am I correct that you have reviewed the direct testimony of MNSC witnesses Napoleon and deLeon?

A. Yes.

Q. Today I'd like to ask you about your rebuttal testimony to those witnesses and follow up on a couple of discovery responses. Hopefully, this shouldn't take too long.

Can we start on page 6 of your rebuttal testimony, Line 2, and just let me know when you're there.

A. Yes, I'm there.

Q. You dispute that -- MEC witness deLeon's statement that natural gas assets will become stranded due to the energy transition; correct?

A. Yes.
Q. In doing so, you note that, quote, "The retirement of coal generation and high cost of nuclear indicates [that] natural gas will likely serve as a reliable, low-cost, baseload fuel for the significant growth in future energy demand through gas generation." Do you see that?
A. Give me a sec here. My page number is not the same as you're reading. This was under witness deLeon?
Q. Yes. Sorry. Page 7.
A. 7. All right.
Q. Page 7, line 9. Apologies if I misstated the page.
A. Okay. Yes, I am there.
Q. And so when discussing baseload fuel, such as coal and nuclear, you're referring to baseload fuel for electricity generation; correct?
A. Yes.
Q. And that's distinct from gas delivery for in-home combustion; correct?
A. Not entirely. The two are -- are not mutually exclusive from each other.
Q. The subject of this rate case is gas delivery for combustion in homes; correct?
A. The subject matter of the case is tied to all of the assets -- asset classes that Consumers Energy Company owns and operates, which is transmission, distribution,

storage, and compression.
Q. And the Company -- the subject of this rate case is the Company's delivery of gas to customers, correct, rather than electricity?
A. Yes. However, customers we have do generate electricity today.
Q. Okay. But the Company's distribution pipelines, for example, or pipes do not serve baseload electricity generation; correct?
A. They do in part. They do in part. And the reason is that all the asset classes contribute to the integrated delivery of gas to all customers, including the distribution system for electric generation. And I'd be happy to expound on that, if needed.
Q. When discussing stranded assets, Ms. DeLeon is referencing the Company's assets for gas delivery, though; is that right?
A. That is correct.
Q. Okay. And the usefulness of gas on the electric side for baseload fuel doesn't really have much to do with the Company's distribution assets for gas delivery; correct?
A. It does. It does. The -- the distribution assets of the Company are integral to managing resiliency and delivery to gas generation customers.
Q. But couldn't the Company's distribution assets become

stranded with lower demand for gas delivery?
A. I don't know.
Q. Could you please refer to, on the Sharepoint, MEC-51.
A. All right. I am there.
Q. If you look at your response F, you say there, "The Company agrees that if gas demand drops low enough, certain natural gas system assets may become stranded."
A. Yes.
Q. And those are -- those are the assets that are primarily for gas delivery; correct? Would you agree that most of the assets in this case are primarily for gas delivery rather than electric generation?
A. Gas delivery includes all customers that we serve. It's hard to segregate the actual use of gas as opposed to the delivery of gas. All of our customers use natural gas for very different purposes across the state.

In regards to subpart F, depending on different outcomes the future may hold, various assets could become stranded, but that's impossible to determine right now based on the uncertainty the future would hold.
Q. Okay. Why don't we just separate just the residential side. The resident -- the residential distribution pipes, those are not serving electricity; right? They're not providing electricity to customers?
A. That's correct.

Q. And so electrification, for example, on the residential side that leads to lower gas demand could create stranded assets when it comes to those particular assets; is that fair?
A. Under certain conditions and circumstances, that -- that could happen.
Q. Looking at this same exhibit, you also state that, quote, "The Company's natural gas assets projected in this case are integral to providing fuel for both electricity and combustion for space heating. Providing gas -- providing gas for generation is not mutually exclusive to heating homes because the same assets contribute to both end uses."
A. Can you repeat where you got that from so I can reference it?
Q. Sure. It's response E.
A. Yes. I got it. Thank you.
Q. What percentage of Company assets supply fuel for electricity generation when you say here -- the reference in here?
A. That's difficult to determine. I don't know.
Q. Okay. Looking back at F, response F, you state that if gas demand drops low enough, certain natural gas systems may become stranded; evidence suggests gas demand is stable, making the scenario unlikely.

Were you here to see Mr. Sherwani's cross-examination?

A. I was not.

Q. Okay. Have you seen the historical evidence that residential gas demand is declining within Consumers' territory?

A. I have not.

Q. Okay. Can you please now turn to page 7 of your rebuttal testimony, line 13.

A. Yes. I'm there.

Q. You state, quote, ..."gas distribution reduces the need for investment in electric generation and infrastructure by about 20 to 25 billion dollars." Do you see that?

A. Yes.

Q. And can you now please bring up MEC-56 on the Sharepoint site.

A. I am there.

Q. There you're asked to produce a source for the 20 to 25 billion dollar statistic, and note that, quote, it ..."is part of a state level analysis using proprietary data modeling through third party expert consultants."

Who conducted this analysis and, like, where does this analysis sit?

A. A third party conducted the analysis; that is, they were expert consultants. They retained the detailed

assessment. The Company has the summary of that modeling analysis.

Q. And where is that summary?

A. That was provided throughout discovery. I can reference specific questions if you need to.

Q. And so there's no underlying data supplied or analysis supplied that kind of shows the work that gets to that 20 to 25 billion dollar estimate?

MS. UITVLUGT: Objection, Your Honor. The witness just testified that the summary of the analysis was provided to the parties in this case through discovery. The witness also just testified that a third party performed the analysis and the third -- the third party held said data.

JUDGE VARCHETTI: Any response, Mr. Shrinath?

MR. SHRINATH: Your Honor, this is the most recent discovery response on this -- on this data point, and I'm not familiar with that summary, so I'm just curious whether that summary includes this analysis or what is included in that summary.

JUDGE VARCHETTI: I'm going to uphold the objection based upon the witness' answer, but I think that Mr. Shrinath is, of course, free to still inquire into the nature of the analysis if the witness has any

knowledge of it. So go ahead and proceed, Mr. Shrinath.

BY MR. SHRINATH:

Q. Yeah, Mr. Dreisig, could you explain what you know of the analysis, what analysis went into this 20 to 25 billion dollar statistic?

A. I'm going to reference discovery response U-21806 MNSC-CE-707. So on this response, it describes the -- how the analysis was performed and the basis for the conclusion that it -- it came to, which is that a balanced scenario of multiple technologies is the least cost to achieving economy-wide decarbonization.

It held that there were six different scenarios that were modeled. And one of the key points that it -- it delivers is that the balanced scenario requires significantly less peak electric load throughout the year; therefore, requiring less electric infrastructure build-out.

Additionally, the balanced scenario leverages the advantages of all technologies, including carbon capture. The alternative, the study also notes, is in the absence of natural gas, additional electric bill -- electric generation, rather, would be tied to the expansion of nuclear energy for additional load increases in the future. I'll stop there.

Q. Okay. So there -- I guess what I'm getting at is there's

no way for us to really verify this number; correct? Because we don't know where it came -- who it came from and we are not able to access the analysis.

A. We are not able to access the analysis. However, this analysis was performed by third party ex- -- experts who do have access to all state-wide demographic information, which includes energy usage across the state.

This was a state-wide analysis, not a Consumers Energy system analysis. And that also included the cost at the time of various technologies, using proprietary modeling data that was also used in other jurisdictions as well.

Q. Okay. And this 20 to 25 billion dollar statistic, that statistic forms part of the basis for the Company not exploring non-pipeline alternatives, like electrification, in its Natural Gas Delivery Plan; correct?

A. The Company -- the Company does investigate non-pipeline alternatives to a large extent.

Q. And I actually wanted to ask about that. So could you please turn to page 8 of your direct testimony, Mr. Dreisig. Let me know when you're there. Sorry. Page 8 of your rebuttal testimony. My apologies.

A. Okay. I am there.

Q. So there you disagree with Ms. DeLeon's contention that, ..."the Natural Gas Delivery Plan shows no evidence that

the Company is pursuing non-pipeline alternatives to meet its customer emission reduction goal"; correct?

A. Correct.

Q. What non-pipeline alternatives did the Company consider in the NGDP?

A. The Company considers all non-pipeline alternatives in the Natural Gas Delivery Plan. We have used the third-party analysis we just discussed to help inform our plans in the Natural Gas Delivery Plan. We also maintain our own decarbonization model that includes all pathways, non-pipeline alternatives.

We also engage heavily in the industry to understand what peer utilities and industry partners are discovering with all pathways towards a decarbonized future. We also collaborate extensively with customers to understand what pathways will best support their needs as well. And we also have demonstrated, moving forward, with some of these non-pipeline alternatives to investigate whether or not they do have benefit for our customers in certain circumstances.

Q. Just to rephrase, like which specific non-pipeline alternatives did the Company consider in the Natural Gas Delivery Plan?

A. Two obvious ones that stick out are our forestry offset program, and then the other one, just most recently being

awarded a state grant to investigate the feasibility of network geothermal technology in our service territory, the work of which is occurring this year.

Q. But in the Natural Gas Delivery Plan, in the list of decarbonization pathways, non-pipeline alternatives are not kind of factored in as -- in terms of a percentage of emissions reductions; correct?

A. Can you repeat the statement.

Q. The Natural Gas Delivery Plan includes various decarbonization pathways and percentages of emissions reductions from those pathways. Non-pipeline alternatives are not included in those; correct?

A. Non-pipeline alternatives are included in the analysis. They do not show up as feasible pathways due to the cost increase they would incur on the customer's part.

Q. Okay. In describing the Company's due diligence on emissions reductions, you list out collaborations with peer utilities, the Low Carbon Resources Initiative, the H2EDGE Program, Michigan Hydrogen Initiative, and the Midwest Alliance for Clean Hydrogen hub. Each of these collaborators works on decarbonization solutions involving pipes; correct?

A. Yes.

Q. And decarbonizing with pipes, such as through RNG or hydrogen, means that Consumers gets to continue to build

out and invest in its distribution and compression network; correct?

A. I -- I will go back. They do investigate pipeline solutions. However, particularly the Low Carbon Resource Initiative, this is a -- an energy agnostic initiative that is seeking to determine the most feasible solutions, regardless of the energy source, to decarbonize our future. It's comprised of both electric only utilities and gas only utilities and combination utilities as well.

Q. Mr. Dreisig, you state that, quote, "It is well understood through these collaborations that non-pipe alternatives that involve introducing new technologies raise cost for customers ... in some cases jeopardize the safety of the gas system."

A. Correct.

Q. Is -- does that contention come from the Company's collaborations with stakeholders that are working on pipe-based decarbonization?

A. That contention comes from stakeholders that are involved on all -- all levels of pathway exploration, not just pipelines.

Q. Would you expect a hydrogen organization to advocate for non-pipeline alternatives?

A. I guess it depends what you mean by hydrogen organization. I'm not aware of any hydrogen organizations.

Q. Would you expect the Michigan Hydrogen Initiative to advocate for non-pipeline alternatives?
A. Yes.
Q. Has Consumers worked with or collaborated with any organizations that actually work on non-pipeline alternatives to --
A. Yes.
Q. -- discern their reliability?
A. Yes.
Q. Which ones?
A. Most recently, we collaborated with Michigan Clean Fuels, which is an industry partner who is advocating for the clean fuel for transportation in Michigan.
Q. And what is -- what was the extent of that collaboration? Actually, let me -- let me rephrase.

Has Consumers actively worked with any organizations working on electrification?
A. Yes.
Q. Which ones?
A. So the -- the organization I just referenced, Michigan Clean Fuels. And I will also note that the Michigan Hydrogen Initiative had a collaboration just recently, which also included 5 Lakes Energy, which is a primary stakeholder in electrification.

The determination that they were

emphasizing is the collaboration between all energy partners is critical in defining what our decarbonized future looks like.

Q. Mr. Dreisig, has Consumers figured out whether customers agree that non-pipeline alternatives are not worth considering?

A. Can you ask the question again, please.

Q. Yeah. So, again, you say, "It is well understood that non-pipe alternatives that involve introducing new technologies raise costs for customers, and in some cases jeopardize the safety of the gas system."

And so what I'm asking is, has Consumers figured out whether customers agree with that contention?

A. I don't know.

Q. And are you saying that electrification is a new technology here?

A. No.

Q. So what new technologies are you referring to?

A. Can you reference the specific section and language with that?

Q. Sure. So on page 9 of your rebuttal testimony, you say, "It is well understood through these collaborations that non-pipe alternatives that involve introducing new technologies raise costs for customers, and in some cases

jeopardize the safety of the gas system."
A. Correct.
Q. "As described above, customers are most interested in reliable, low-cost energy, not more expensive non-pipe alternatives."
A. That's correct. And can you -- what is the specific question to that?
Q. My question is, first of all, do you consider electrification a new technology?
A. What I reference as new technologies are technologies that would be introduced as an altern- -- a clean fuel alternative to natural gas was the -- the intent behind "new" in that -- in that phrase, but to your question, there are also new technologies that are not widely demonstrated in the industry, such as electrolysis and carbon capture as well.
Q. Are heat pumps and heat pump water heaters new technologies?
A. No.
Q. Okay. Would you agree that they're abundantly commercially available?
A. Yes.
Q. So there are non-pipeline -- none-pipe alternatives that are not new technologies; correct?
A. They are not new in the sense of, I would say,

technological maturity, but they would be new in the sense of energy delivery to our customers.

Q. But on the electric side, there are plenty of customers who heat their homes with electricity; correct?

A. I don't know.

Q. You can't say whether there are customers who heat their homes with electricity?

A. There are customers who heat their homes with electricity. I do not know the size of that market.

Q. Okay. You reference here that non-pipe alternatives could jeopardize the safety of the gas system. How does electrification jeopardize the safety of the gas system?

A. That statement is more tied to a pathway, for instance, of blending hydrogen into the system, not -- not necessarily electrification.

Q. Isn't hydrogen a pipe alternative -- a non-pipe alternative?

A. Hydrogen can be a non-pipe alternative.

Q. Okay. So, then, electrification -- so when you say that non-pipe alternatives are new technologies and that they can introduce -- that they can jeopardize the safety of the gas system, you're not referring to electric plants? You're not referring to electrification?

A. Correct.

Q. And so when you say, ..."customers are most interested in

reliable, low-cost energy, not more expensive non-pipe alternatives," you're not -- you're not referencing electrification?

A. I am referencing electrification.

Q. So I'm -- I'm a little confused, because it feels like there's a conflation of electrification and other non-pipe alternatives. And so my -- what I'm trying to get at is, it seems like the Company has put non-pipe alternatives aside, including electrification, in its suite of resources for the Natural Gas Delivery Plan, and I'm wondering why electrification has been lumped in as a new technology and a -- and a non-pipe alternative that would jeopardize the safety of the gas system.

A. The -- the notion of jeopardizing the safety of the gas system is -- is more tied to new clean fuels, such as hydrogen. The Company does investigate electrification and uses to a great extent.

Electrification, I will note, is available to customers today. There is nothing that forbids them from choosing that. And what we have learned from customers is that those non-pipe alternatives would increase their cost, which is why part of the Natural Gas Delivery Plan is based on serving customers to fulfill their needs.

Q. If a non-pipe alternative, say electrification, is more

cost effective for an individual customer than piping, let's say, RNG into their homes, would Consumers support that non-pipe alternative?

A. If a customer was asking for it and it was demonstrated to be a reduction in cost, then that is something that Consumers Energy would support.

Q. And has Consumers studied the viability of electrification, either pilots or otherwise, in places where it is cost competitive?

A. I'm not aware of any place in our service territory where it would be cost competitive.

Q. Okay. Can you turn to MEC-67, and then scroll to page 17 within that proposed exhibit.

A. Is that located on the Sharepoint site?

Q. It should be, yes.

A. I -- I do not see it. Let me refresh. Okay. 67. Give me a sec here.

Q. And then page 17 of the exhibit, which is page 9 of the attachment.

A. Say that one more time. Which page?

Q. Page 17 of the exhibit, which is page 9 of the attachment that you supplied.

A. Page 7 of the -- of the exhibit?

Q. Page 17 of the exhibit.

A. 17.

Q. Yeah.
A. Is that the section titled, "stakeholder engagement"?
Q. It's the abatement cost chart. So if you look on the top right of the exhibit -- you're looking at MEC-67; correct?
A. I am on MEC-67. It's not --
Q. Sorry. Go ahead.
A. Yeah, I -- I believe I'm there. It's -- it looks like page 9 of the actual exhibit itself.
Q. Correct. Yeah.
A. Okay. Yes, I am there.
Q. So this is an attachment that you supplied as a supporting document for your decarbonization -- decarbonization cost analysis. Do you recognize this?
A. Correct. Yes.
Q. It's a study conducted by ICF to assess RNG, renewable natural gas, in Michigan?
A. Yes.
Q. And this chart shows abatement cost by measure. And as you can see, there's a relatively large range for building electrification, including part of the range well below other -- other abatement measures, including RNG, and then a relatively large range for RNG as well.

Your abatement -- your decarbonization study picks a relatively high estimate for these abatement costs, right, around $500?

A. For which -- for which pathway?
Q. For building electrification.
A. That's correct.
Q. And it picks -- but for RNG, it -- it identifies an abatement cost of, I think, about $215; is that right?
A. That's correct.
Q. And that's on the -- that's on the low end of this range; is that fair?
A. Yes.
Q. Okay. And now I want to just ask you a few questions about renewable natural gas. Renewable natural gas is a considerable -- or is a significant part of Consumers' Natural Gas Delivery Plan strategy; correct? Emissions reduction strategy.
A. Yes.
Q. Has Consumers mixed and injected RNG into pipelines before?
A. Yes.
Q. Has it treated biogas before?
A. Consumers Energy has not treated biogas before.
Q. Can you turn to MEC-53, please.
A. I am there.
Q. Great. So here you provide a response to a question asking how you could say that, quote, "No infrastructure modifications are required for RNG." On page 2 of this

response, do you concede that, quote, "Depending on the feedstock supply distance from an existing pipeline, lateral pipelines may be required for interconnection"?

A. Yes.

Q. Are these costs incorporated into Consumers' assessment of RNG's marginal abatement cost?

A. Yes.

Q. You also note that raw biogas has to be cleaned on site prior to injection. Is that treatment cost incorporated into Consumers assessment of RNG's marginal abatement cost?

A. Yes.

Q. If we flip to the next page, you see some marketing materials Consumers produces to sell RNG to Consumers -- or to customers.

Does Consumers produce any such materials for electrification or for thermal energy networks?

A. I don't know.

Q. Okay. Can you now flip to page 9 of your rebuttal testimony, Line 7. Just let me know when you're there.

A. I am there.

Q. So here you dispute MEC witness Napoleon's contention that the Company's decarbonization study's inconsistent with the academic literature -- with other studies; is that

fair?
A. Yes.
Q. In doing studies, you cite to one study, the Low Carbon Resource Initiative, which you said, quote, ..."was used to test the outputs of the Company-led study, showing similar findings."
Can you please turn to MEC-55.
A. I'm there.
Q. So here you respond to our request to produce the study that the Company used to vet its decarbonization study, and you state, quote, "I do not have ready access to the full report," and instead supply the executive summary.
Did you read the full report, Mr. Dreisig? Did you have access to the full report at some point?
A. I have not read the full report. I do not know if I have access to that full report or not.
Q. So how did you compare the Company's decarbonization study or vet the Company's decarbonization study with the LCRI report if you didn't have the full report?
A. Because the executive summary actually goes into a lot of detail on the key findings of the report in a similar way that the third-party modeling summary also described the pathways for us. Very similar in nature.
Q. Did you compare the abatement costs for various fuels in

the decarbonization study to the abatement costs in the LCRI report?

A. The LCRI report, to my knowledge, did not include abatement costs. But I would not use the abatement costs in that study even if it existed to compare against our own abatement costs here in Michigan.

Q. So you vetted some general findings from your study with the executive summary of this study, that that constitutes that verification?

A. Yes.

Q. Okay. In your rebuttal testimony, you state, "The Company performed the decarbonization study from an energy agnostic standpoint to truly understand the most effective way Michigan can decarbonize energy use. It was not in any way biased towards natural gas."

Can you please turn to MEC-57 now.

A. I am there.

Q. So there you describe how the Company's decarbonization study compared the carbon intensity of electricity to the carbon intensity of gas. You state that, quote, "When performing life cycle analysis, one must use the broader electric grid to determine the actual level of emissions. The blended average of all utilities contributing to the overall MISO electric system must show a carbon intensity less than natural gas to show any meaningful carbon

reduction against natural gas use." Do you see that?
A. Yes.
Q. So did the Company assume that a Consumers Energy electric customer uses equal parts of electricity from each of MISO's blended utilities?
A. It's impossible to -- to know where the exact source of electricity is coming from. The MISO grid is analogous to a lake, and the streams flowing into a lake don't determine where -- where you actually pull water out.

It's the same thing for an electric customer here in Michigan. We would pull in electricity sourced from various parts of the MISO grid, which would be impossible to determine where that would be.
Q. Okay. So in the chart, under question 8 of the stated response, wouldn't Consumers' electric grid be substantially cleaner from a carbon intensity standpoint than gas combustion?
A. The charts, you said right under question 8; correct?
Q. Yeah. That's from Consumers' website, I believe.
A. Yeah. Can you rephrase the question -- or restate the question.
Q. So based on that chart, under question 8, wouldn't Consumers' electric grid be substantially cleaner from a carbon intensity standpoint than gas combustion?
A. Consumers Energy's grid will be, yes, but that is not the

comparison you can make when you're talking about decarbonization of the natural gas system. It needs to represent the electric grid by which you are electrifying end uses, which would be the MISO footprint.

Q. And are there decarbonization initiatives in other utilities under MISO?

A. I don't know.

Q. So you -- so for the purposes of this carbon intensity analysis, you used a MISO level carbon intensity without looking at -- into whether there's decarbonization initiatives in the various other parts of the MISO grid?

A. I looked at the carbon intensity of the MISO grid as it sits in reality today, which shows that it is 40 percent more carbon intensive than natural gas uses as of today.

Q. Can you now turn to the Sharepoint MEC-61.

A. I am there.

Q. So you were asked to describe how the Company developed allocations for decarbonization measures as expressed by percentage of natural gas throughput decarbonized, and you note that these percentages were updated based on a slew of factors, including technology life cycle emissions reduction updates, external policy trends, utility trends -- peer utilities trends, sorry, discussions with customers, maturity of technologies and tax credit guidance. You note that discussions with customers and

utilities informed a six percent gas -- gas displacement estimate for hydrogen by 2050.

Does the Company have a, like, qualitative or quantitative framework through which it arrives at these numbers in Appendix C of the NGDP?

A. These numbers were originally based on the third-party decarbonization modeling we received. We then used the basis for those numbers and compare that to all of the parameters that you listed out to -- to see whether or not it's warranted to adjust those factors based on what we're seeing here in Michigan.

Q. Who picks what the number is?

A. The employees of the -- of the gas utility pick those numbers in collaboration with other departments in Consumers Energy Company, including the electric utility, including our customer service organization, and in collaboration with industry partners as well.

Q. Could you explain a little like what that looks like? So, you know, we have this -- let's say we have a percentage for -- the six percent percentage for hydrogen as a percent of decarbonization. Does someone propose that number and there's a debate? Is there a -- a research process? Is there a stakeholder process? How does -- how do you -- how do you come to the six percent number? And how -- how can ratepayers trust it?

A. The six percent number in this specific case was derived by the third-party expert consultants. When we receive that number as a base assumption, we would -- we would identify which customers we do have in our territory that use hydrogen, and we would work with our customer service organization to engage with those customers to understand whether or not they have an interest in decarbonizing that energy use.

And depending on what the customers tell us, there is quite a bit of -- of collaboration that exists in -- with them, and at times, the response -- if we -- depending on the response, we would either increase that number or decrease that number.

And part of that collaboration includes the technical feasibility and components from our industry partners. So we would bring those industry partners and their insights into the collaborations with customers to make sure that they have a good understanding of what that solution could mean from the -- for their business.

Q. So this is like a holistic analysis that happens completely outside the purview of what like a ratepayer may see as going through a gas rate case; is that fair?

A. Outside of the gas rate case, correct.

Q. And correct me if I'm wrong, but the percentage for electrification in terms of displacement of gas emissions

is zero, right, in Appendix C?
A. In appendix -- can you describe Appendix C?
Q. Appendix C of the Natural Gas --
A. Oh.
Q. -- Delivery Plan.
A. Appendix C. Yes. Appendix C would -- would -- would impute a reduction in gas throughput tied to electrification by 2050, but, again, that -- that base assumption would be validated with collaborations with customers on an iterative -- iterative basis.
Q. Okay. Can you now turn to MEC-64.
A. I am there.
Q. So you concede here that the Company has not yet assessed where hybrid heating and heat pump technology can best serve customers; correct?
A. State that one more time, please.
Q. In response A here, you concede that the Company has not assessed -- not yet assessed where hybrid heating and heat pump technology can best serve customers?
A. Correct.
Q. You also note that, "The Company does not have current plans to deploy or support hybrid heating through 2030 and 2050." And, "The customer research will continuously monitor behavior and preferences to assess the future need to support hybrid heating and heat pump technology." Do

you see that?
A. I do.
Q. What -- what customer research is the Company doing, currently doing, to assess the viability of heat pumps and hybrid heating? Is there a systematic plan? Is there --
A. That research is -- I don't know that research exists in a different department under Consumers Energy Company, but in addition to that research, we do use third party research materials to help inform that.

For example, discovery question MNSC-573 shows a third party study through Cadmus and U of M that both helped inform our path forward, that both conclude that electrified end uses do in fact raise costs for customers.
Q. I guess just to rephrase, there's not like a systematic research in the evaluation framework or plan that the Company goes through? This is all ad hoc, kind of, you know, somewhat arbitrary?

MS. UITVLUGT: Objection, Your Honor. First of all, the witness already indicated that this research is formed within another division of Consumers Energy and not by himself.

He then, also, if you read the entire discovery response, is actually saying we haven't assessed it, but we are in the process of evaluating key pump

technologies with Michigan residents served by non-regulated fuels.

I object not only to the characterization of the witness' testimony, but also to the -- yeah, just to the characterization of the witness' testimony.

JUDGE VARCHETTI: Mr. Shrinath, any response?

MR. SHRINATH: The -- the data response distinguishes between assessing the -- or evaluating heat pump technology for non-regulated fuels, such as like propane and -- and gas. I'm asking about heat pump technologies and hybrid heating for gas, and I think that's what's in the scope of --

MS. UITVLUGT: I --

MR. SHRINATH: -- the discussion.

MS. UITVLUGT: I would repeat, Your Honor, that the witness has already indicated that the research is being taken in a different division outside of his at Consumers Energy.

JUDGE VARCHETTI: So I'm going to sustain the objection with the qualification that Mr. Shrinath, of course, asked for details about this to the extent the witness knows it. I'm sustaining it with the regard to the fact that it was somewhat

argumentatively phrased.

MR. SHRINATH: Understood, Your Honor.

BY MR. SHRINATH:

Q. Mr. Dreisig, are -- are you aware of any systematic plan to assess the viability of hybrid heating and heat pump technologies for natural gas conversion within Consumers?

A. I know those efforts exist within the Consumers Energy Company organization. I do not know the detail -- specific details of those plans.

Q. Okay. Last, can we please turn to MEC-68 on the Sharepoint site.

A. I am there.

Q. You state in this data request that Consumers has not incorporated emissions reduction goals into new connection forecasting; correct?

A. Correct.

Q. And are you aware that Consumers is projecting an increase in new connections?

A. I am not aware of that. And in the purposes of modeling decarbonization pathways, that is irrelevant for the model itself.

MR. SHRINATH: Well, thank you, Mr. Dreisig. This is -- I appreciate your patience. That's the last of my questions.

Thank you, Your Honor.

Oh, actually, I just realized I should probably ask to bind exhibits into the record, if I may.

JUDGE VARCHETTI: Certainly.

MR. SHRINATH: Your Honor, I would move to bind Exhibits MEC-51, MEC-56, MEC-67, MEC-53, MEC-55, MEC-57, MEC-61, MEC-64, and MEC-68 into the record.

JUDGE VARCHETTI: All right. That was quite a few exhibits. Was there any objection to the binding in of exhibits?

And correct me if I'm wrong, Mr. Shrinath, those were Exhibits MEC-51, 56, 67, 53, 55, 57, 61, 64, and 68, which were the exhibits that we went over during your cross; correct?

MR. SHRINATH: Correct, Your Honor.

JUDGE VARCHETTI: All right. Are there any objections to the admission of these exhibits?

MS. UITVLUGT: No, Your Honor.

JUDGE VARCHETTI: In that case, the exhibits mentioned are admitted.

Then, I believe, Mr. Shrinath, you said that was the conclusion of your cross-examination?

MR. SHRINATH: Yes, Your Honor.

JUDGE VARCHETTI: Does the Company wish to take any time to confer with the witness to determine if any redirect is needed?

MS. UITVLUGT: Can we have five to ten minutes, Your Honor, just for like a morning break and reshuffling, and I can do both at the same time?

JUDGE VARCHETTI: That sounds like an excellent idea. Let's take a ten-minute break. We'll -- it's currently 10:05. Let's come back at 10:15.

So we are now off the record. We'll reconvene at 10:15.

MS. UITVLUGT: Thank you.

(At 10:05 AM, recess was taken)

(At 10:15 AM, proceedings resume)

JUDGE VARCHETTI: All right. We are now back on the record after taking a quick ten-minute break.

Does the Company have any redirect questions for the witness?

MS. UITVLUGT: No, Your Honor.

JUDGE VARCHETTI: Excellent. In that case, we can move on to the matter of admitting the exhibits associated with this witness, which, and please correct me if I'm wrong, were Exhibits A-42 and A-133, which had a redacted public version and a confidential version.

So are there any objections to the admission of the two exhibits just mentioned?

Hearing none, then, Exhibits A-42 and A-133 are admitted.

And I believe, correct me if I'm wrong, there was no other attorney that desired to question this witness, correct, was my understanding?

MS. UITVLUGT: That is my understanding, Your Honor.

JUDGE VARCHETTI: All right. Excellent. In that case, Mr. Dreisig, you are excused as a witness.

THE WITNESS: Thank you.

JUDGE VARCHETTI: All right. Ms. Gill, you have a question. Do you want to go off the record or --

MS. GILL: Yes.

JUDGE VARCHETTI: Okay. Let's go off the record for a minute.

(At 10:17 AM, recess was taken)

(At 10:20 AM, proceedings resume)

JUDGE VARCHETTI: We are now back on the record after a short break.

Before we move on with the binding in of testimony, I would just like to note that for the record, I have discussed with the Company the possibility of stipulating on the record that the same exemption from

signing the nondisclosure -- nondisclosure agreement for the presiding ALJ, that being myself, also extends to members of MOAHR's Public Service Commission Division, which would include other administrative law judges and administrate law specialists and administrative assistants who are assisting me with the proposal for decision, that they do not have to sign the NDA in order to see confidential information that is filed in this case.

Was the Company willing to make that stipulation that they are exempt as well?

MS. UITVLUGT: Yes, Your Honor, the Company will agree to that stipulation -- or make that stipulation.

JUDGE VARCHETTI: Oh, thank you. I appreciate that.

With that matter being taken care of, we can now move on with the rest of the Company's evidentiary presentation.

MS. UITVLUGT: Thank you, Your Honor.

MR. RUSZKIEWICZ: Good morning, Your Honor. Attorney Mark Ruszkiewicz, appearance for the Company.

JUDGE VARCHETTI: Good morning.

MR. RUSZKIEWICZ: Good morning. I'd like to begin with witness Stacy H. Baker, please. And

based on the stipulation of the parties, the Company moves to bind in Ms. Baker's confidential direct testimony, which consists of a cover page and 123 pages of prefiled testimony; also, Ms. Baker's rebuttal testimony, also confidentially filed, which is a cover page and 46 pages.

The Company also moves to admit Ms. Baker's exhibits, which consist of A-17, A-18, A-19, A-12 Schedule B-5.1, confidentially filed and redacted A-20, A-21 confidentially filed and redacted, A-22, A-23 confidentially filed, A-24, A-25, A-26 confidentially filed, A-109, A-110, A-111, A-112, A-113, and A-158.

Next, the Company, based on stipulation of the parties, moves to bind in the testimony of Marc R. Bleckman. I begin with the direct testimony, which consists of a cover page and 40 pages of prefiled testimony. Mr. Bleckman also had rebuttal testimony, which consists of a cover page and 52 pages of direct -- or of prefiled testimony rebuttal.

The Company also moves to admit Mr. Bleckman's exhibits, which consist of A-14 Schedule D-1, A-14 Schedule D-1a, A-14 Schedule D-1e, A-14 Schedule D-2, A-14 Schedule D-3, A-14 Schedule D-4, A-14 Schedule D-6, A-30, A-31, A-32, A-33, A-34, A-35, A-36, A-106, A-107, A-114, A-115, A-116, A-117 and A-18 -- also A-118, if I didn't say that already. I apologize.

JUDGE VARCHETTI: Was that all for -- and just to jump in for a second, if possible, I would like to do the admission witness by witness. So after you're done asking for the admission of the witness' testimony and their associated exhibits, I would then like to -- I would then ask you to move for the bind-in of that testimony so that we can address it witness by witness.

MR. RUSZKIEWICZ: Yes, Your Honor.

JUDGE VARCHETTI: Okay. So perhaps we can just pause for a second, and let me ask, was there any objection to the admission of the confidential direct and confidential rebuttal testimony of witness Baker or any of the exhibits associated with her?

I'm hearing none. Then the testimony and exhibits associated with Mr. -- with Ms. Baker that was requested to be admitted are admitted.

(Redacted Direct and Redacted Rebuttal Testimony bound in)

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

| | | |
|---|---|---|
| In the matter of the application of<br>**CONSUMERS ENERGY COMPANY**<br>for authority to increase its rates for the<br>distribution of natural gas and for other relief. | )<br>)<br>)<br>)<br>) | Case No. U-21806 |

**REDACTED**

# DIRECT TESTIMONY

**OF**

**STACY H. BAKER**

**ON BEHALF OF**

**CONSUMERS ENERGY COMPANY**

December 2024

**Q. Please state your name and business address.**

A. My name is Stacy H. Baker, and my business address is One Energy Plaza, Jackson, Michigan 49201.

**Q. How long have you worked for Consumers Energy Company ("Consumers Energy" or the "Company") and what positions have you held?**

A. I have worked for the Company for over twenty-three years in various individual contributor and leadership positions. The first nine years were in the Finance Department as an Accounting Analyst performing responsibilities to support Payroll and Accounts Payable and later as the Payroll Manager during the SAP Implementation. Thereafter, I moved to the Information Technology ("IT") Department where I have held a number of positions including Enterprise Resource Planning ("ERP") Portfolio Manager, Director of Business Relationship Management – Corporate Services, and Executive Director of IT Business Technology – Corporate Services. In these roles I focused on technology supporting corporate areas of the Company and had IT departmental responsibility for the delivery and operation of IT applications for Finance, Human Resources ("HR"), Supply Chain, Legal and Government, Regulatory & Public Affairs. I am currently the Director of Technology Portfolio Office responsible for portfolio management of the Company's IT, Security, and Operational Technology ("OT") assets, project management office including agile services, project delivery organization, and organizational change management. This includes the management of the IT long-term financial plan,

administration of portfolio management, cloud financial management, development of testimony and exhibits, and supporting rate cases for the IT Department.

**Q. Would you please state your educational background?**

A. I earned a Bachelor of Science in Business Administration degree from Central Michigan University in December 1992 with a major in Accounting.

**Q. Have you ever testified in any other proceedings before the Michigan Public Service Commission ("MPSC" or the "Commission")?**

A. Yes. I testified in the following cases:

- Case No. U-21308 – 2022 Gas Rate Case; and
- Case No. U-21490 – 2023 Gas Rate Case.

**Q. What is the purpose of your direct testimony in this proceeding?**

A. The purpose of my direct testimony is to describe the Operating and Maintenance ("O&M") expenses and capital expenditures needed by the IT Department to maintain and secure existing IT and security systems and enable new capabilities and services to support safe, affordable, and reliable natural gas. I also provide an overview of increasing threats in both Cyber Security and Physical Security areas, their evolution over time, and the changing regulatory landscape that necessitates increased O&M funding. These increases are essential for advancing cloud computing solutions, maturing security capabilities, and protecting the Company's technology and physical infrastructure.

Furthermore, my direct testimony provides an explanation of the Company's plans for deterring threats before they impact the Company and its customers, detecting malicious activity, and recovering quickly with minimal impact while complying with all regulations.

The benefits of increasing technology use for customers, and the Department's support of the Company's commitments outlined in the Natural Gas Delivery Plan ("NGDP") will also be highlighted. Lastly, the importance of achieving full recovery of the requested expenses and expenditures to provide the best value to the Company's customers will be demonstrated.

**Q. Please summarize the main portions of this testimony.**

A. My direct testimony discusses the following:

- The importance to customers of digital investments and the role of IT to build and support those investments;
- Changes in the functions of the IT Department;
- Support for Operational O&M expense funding;
- A description of the investment, both O&M and capital, needed to keep the Company's systems secure, current, stable, and supporting new capabilities;
- Definition and rationale for the use of reduced Rough Order of Magnitude ("ROM") estimates and explanation of the difference from contingency requests;
- An explanation of the projects included in this rate case filing for the IT Department and their supporting business plans, as described in Confidential Exhibits A-20 (SHB-5) and A-21 (SHB-6);
- Company action to address previous Commission concerns, including:
  - Company total one time project cost across multiple years,
  - Total Company cost of ownership of each project beyond initial one-time project investment,
  - Recurring hard savings over the life of the investment, and
  - Cost benefit ratio calculated by the Company's internal Business Planning System ("BPS");
- Individual project synopses and requests to support gas and customer plans;

- Individual project synopses and requests to support corporate functions crucial to running an efficient business;
- Individual IT project synopses with supporting, detailed exhibits for the Asset Refresh projects and the Application Currency projects;
- Individual IT project synopses with supporting, detailed exhibit (Exhibit A-24 (SHB-9) for Enhancement projects, along with a detailed worklist of the enhancement work backlog found in Exhibit A-25 (SHB-10);
- Individual IT project synopses for the IT/Digital Foundations and Capabilities projects;
- Further information about and justification of several larger and more complex projects for which projected spending varies from amounts forecasted in Case No. U-21490, including the following projects:
  - Gas Supervisory Control and Data Acquisition ("SCADA") Software Solution,
  - Asset Refresh Program ("ARP") – Field Device Asset Management ("FDAM"),
  - ARP-Radio,
  - ARP-Server and Storage,
  - ARP – Workstation Asset Management ("WAM"),
  - SAP High-performance ANalytic Appliance ("HANA") Database Migration, and
  - IT Operations Management – Service Operations; and
- Further information about and justification of the more complex SAP S/4HANA Implementation project.

**Q. What exhibits are you sponsoring in this proceeding?**

A. I am sponsoring the following exhibits:

| | |
|---|---|
| Exhibit A-17 (SHB-1) | Summary of Actual and Projected Information Technology Operations O&M Expense for the Years 2023, 2024, 2025, and Test Year 12 Months Ending October 31, 2026; |

| | | |
|---|---|---|
| Exhibit A-18 (SHB-2) | | Historical and Projected 13-Month Average of IT Cloud Computing Prepaid Balance for the historical years 2023 - 13-month balance ending December 31, 2024, and for the projected years 2025 – 13-month balance ending October 31, 2026; |
| Exhibit A-19 (SHB-3) | | Summary of Actual and Projected Information Technology Investments O&M Expense for the Years 2023, 2024, 2025, and Test Year 12 Months Ending October 31, 2026; |
| Exhibit A-12 (SHB-4) | Schedule B-5.1 | Projected Capital Expenditures Information Technology Summary of Actual and Projected Gas and Common Capital Expenditures; |
| Confidential Exhibit A-20 (SHB-5) | | Synopses Containing Descriptions, Scope, Benefits, Implementation Dates and Detailed Costs of Actual and Projected Gas & Common Capital Expenditures and O&M Expenses for the Years 2023, 2024, 2025, and 2026; |
| Confidential Exhibit A-21 (SHB-6) | | Business Case Executive Summaries for Historical, Bridge Period, and Test Year Projects; |

| | |
|---|---|
| Exhibit A-22 (SHB-7) | Asset Refresh Programs Projected Gas and Common Capital Expenditures, For the Projected Year 2025 and Test Year Ending October 31, 2026, and For the Historical and Projected Years 2023 and 2024; |
| Confidential Exhibit A-23 (SHB-8) | Application Currency Programs Projected Gas and Common Capital and O&M Expenditures for the Years 2025, 2026, and Test Year 12 Months Ending October 31, 2026; |
| Exhibit A-24 (SHB-9) | Projected Versus Actual Enhancement Capital Expenditures and O&M Expense Summary and Analysis; |
| Exhibit A-25 (SHB-10) | Enhancement Worklist Detail for Years 2016 through March 15, 2024; and |
| Confidential Exhibit A-26 (SHB-11) | Projected 13-Month Average of IT S4/HANA Cloud Implementation Costs for the projected years 2025 – 13-month balance ending October 31, 2026. |

**Q. Were these exhibits prepared by you or under your supervision?**

A. Yes.

**DESCRIPTION OF THE IT DEPARTMENT**

**Q. Please describe the purpose of the IT Department.**

A. The purpose of the IT Department is to provide and maintain reliable and secure digital solutions and services that support the delivery of business objectives, including execution

of the Company's NGDP. Inherent in those objectives are the Company goals to provide a safe, reliable, affordable, and clean gas supply.

The IT Department strives to find the appropriate balance of value and cost in digital solutions. The Company's evolving and pragmatic approach to digital solutions supports many best practices, including:

- Executing work in an efficient and effective manner while remaining flexible as deliverables change by adopting agile frameworks and platform and product-centric operating models that allow the Company to adjust to changing demands on the IT system;
- Equipping coworkers with digital skills through training that enable them to deliver business value faster to ensure the Company meets customer expectations;
- Moving to cloud solutions where and when appropriate to reduce cost, improve security, and increase the speed of providing new capabilities;
- Treating data as an asset and deploying analytics on a larger scale for effective decision making, optimization of existing assets, and efficient investment prioritization;
- Deployment of a consistent asset management system and integrated control systems to reduce risk, optimize and digitize processes, and monitor the health of the system to identify necessary preventative maintenance that reduces waste and long-term costs;
- Ensuring customer data is safe and secure, their privacy is protected, and both critical technology assets as well as critical infrastructure assets are secure; and
- Managing security risks and mitigating associated threats.

**Q. Have there been any changes to the IT functions that are new in Case No. U-21806?**

A. Yes. The following changes have been integrated in my direct testimony and exhibits: (1) the Security Department is part of the IT Department and no longer represented by a separate witness; (2) the Company has integrated the analytics function (Analytics and Outreach) that was part of the Customer Interactions function into the IT Department; and (3) the Company has also integrated the analytics function that was a part of the Process,

Analytics & Technology function, within Operations Performance, into the IT Department. These changes, new in Case No. U-21806, better centralize the Company's technology expenditures and expenses.

The Security Department capital expenditures and O&M expenses will continue to be represented as a separate business category in testimony and exhibits, while the Analytics expenses and expenditures will be represented in the IT business category for Operations O&M expense and the appropriate business category for capital expenditures and Investments O&M expense.

**Q. Please describe the functions the IT Department performs.**

A. The IT Department provides secure digital solutions and services to the Company's customers and internal business units. This includes identification, delivery, operational support, and maintenance of both on-premise and cloud software solutions and computing and communications infrastructure and analytics to support customer safety and reliability. The IT Department also provides the day-to-day operational support for coworkers using technology, whether that technology is a desktop, laptop, or mobile device (e.g. ruggedized field device, tablet computer, cell phone, smartphone, or other handheld device).

The scope of the IT Department also includes OT. OT is the set of real-time industrial control systems that monitor and control the Company's critical gas infrastructure, such as the Gas SCADA systems.

Additionally, the scope of the IT Department includes Security. Security exists to deter threats prior to impacting the Company, detect when malicious activity does occur, recover quickly with minimal effect if or when a threat is successful in causing impact, and

comply with all governmental and industry regulations. Security sets standards based on external threats and guides security work required by the IT and OT teams.

**Q. How does technology support the Company's gas plans?**

A. Technology is an integral part of all aspects of the Company's gas strategy from gas delivery all the way to the customer. The NGDP outlines the need to invest in both IT and OT to provide the following essential digital capabilities that will enable the Company to deliver safe, reliable, and affordable natural gas to customers while transforming the system to deliver cleaner fuels for a decarbonized future. These include: (1) expanding system monitoring to support 24/7 system control; (2) improving data analytics to support asset reliability and identification of optimal utilization of compression and storage assets; (3) modernizing the distribution and transmission system; (4) incorporating predictive and condition-based maintenance; (5) transforming work and asset management; (6) ensuring cyber security of Company assets and complying with security-related regulations; and (7) achieving methane reductions.

This requires investments in new technology, as well as enhancing existing technology assets and processes to keep them operating safely and securely in support of the Gas Safety Management System and increasing regulation which I describe later - specifically in the areas of asset management, work management, system automation and control, security and privacy, and advanced analytics.

The use of technology is also essential to establishing data analysis techniques to understand, communicate, and engage with the Company's customers in a meaningful way; connecting with customers using their channel of choice; enhancing the Company's digital resources in response to growing customer feedback that they prefer "self-service" through

digital channels; providing customers accurate, timely energy bills, and consistent payment processes; and offering options for customers to understand their energy consumption.

**Q. What are some of the biggest challenges the IT Department currently faces?**

A. A big challenge the IT Department currently faces is the integration and implementation of emerging technologies, data, and analytics needed to achieve the Company's goals described in the NGDP. The Company relies heavily on accurate data and high-performing systems that can handle higher transaction and data volumes. Customers depend on these same systems to report gas leaks, receive timely information on consumption, and start or stop service. It is important that the Company achieve full recovery of requested expenses and expenditures to keep these systems updated with the latest security and maintenance patches while delivering new capabilities to help restore customers faster.

Another challenge is that security continues to be a significant risk area and challenge for utilities. Traditional physical security issues of protecting publicly accessible, geographically dispersed critical infrastructure are and will continue to be exacerbated as resources become more distributed. Cyber security concerns include privacy, data breaches, ransomware, ransom extortion, denial of service (an attack meant to shut down a machine or network, making it inaccessible to its intended users), and critical infrastructure attacks. For example, a February 7, 2024 Cybersecurity Advisory from the Cybersecurity and Infrastructure Security Agency ("CISA") states that the CISA, National Security Agency, and Federal Bureau of Investigation assess that People's Republic of China ("PRC") state-sponsored cyber actors are seeking to pre-position themselves on IT networks for disruptive or destructive cyberattacks against U.S. critical

infrastructure in the event of a major crisis or conflict with the United States.[1] The U.S. authoring agencies have confirmed that the PRC state-sponsored cyber group known as Volt Typhoon has compromised the IT environments of multiple critical infrastructure organizations - primarily in Communications, Energy, Transportation Systems, and Water and Wastewater Systems Sectors - in the continental and non-continental United States and its territories, including Guam.

While cyber security is no longer a new area, each year impacts from cyber security incidents increase. According to a 2024 Sophos report on the state of ransomware, while the rate of ransomware attacks dropped slightly since 2023, the average payout more than doubled from $1,500,000 in 2023 to $3,900,000 in 2024. In addition to ransomware, data breaches, ballooning the North American Electric Reliability Corporation ("NERC")/ Critical Infrastructure Protection ("CIP") compliance fine maximums, and the federal government warning regarding potential critical infrastructure attacks from Russia or China as part of global geo-political tensions, utility security teams must be prepared with plans that address the need for securing customer data, maintaining compliance, protecting customer privacy, and protecting the critical infrastructure that serves the Company's customers.

**Q. Please further explain the current environment with respect to cyber threats facing utility companies.**

A. Cyber threats are increasing. The most glaring example is ransomware as discussed above. These threats have increased, not only in their impact but also their level of sophistication. Criminal groups are profiting on ransomware, and it has become such a lucrative business

[1] Available at https://www.sophos.com/en-us/content/state-of-ransomware.

that they now conduct cyberattacks in a more sophisticated manner with teams of people who focus on an individual target. Such groups are more focused on Fortune 500 companies because of the potential for large ransom payments.

The Progress Software "MoveIT" extorsion event demonstrates this increase in sophistication. A zero-day vulnerability (a flaw in a system or device that is unknown and does not have a fix available to correct the flaw, rendering the system vulnerable) was used to compromise the data of hundreds of MoveIT customers across all industries. The ability to exploit zero-day vulnerabilities has historically only been within reach of nation-state actors, not criminal groups. The amount of money being made has allowed these groups to invest in finding such vulnerabilities and dramatically increased their capabilities. The Company sees, on average, several hundred cyber security events daily. This volume demands a robust security program with various layers of defense. No single tool, person, or process can protect the Company's assets 100% of the time; therefore, the Company must rely on multiple lines of defense to meet these challenges.

Beyond ransomware, nation-state actors have a strong interest in United States critical infrastructure. The federal government has repeatedly called out this risk and has been imploring critical infrastructure owners to increase their capabilities. The Biden Administration released a memo titled "National Security Memorandum on Improving Cybersecurity for Critical Infrastructure Control Systems" ("National Security Memo").[2] The implications of the National Security Memo are clear.

First, the threat to critical infrastructure is real and no longer theoretical. Even the Company has seen intrusion attempts from nation-state level actors. The National Security

[2] Available at https://www.whitehouse.gov/briefing-room/statements-releases/2021/07/28/national-security-memorandum-on-improving-cybersecurity-for-critical-infrastructure-control-systems/.

Memo provided that "[t]he cybersecurity threats posed to the systems that control and operate the critical infrastructure on which we all depend are among the most significant and growing issues confronting our Nation."

Second, cyber security of critical infrastructure is a national security issue and priority. The National Security Memo explained that "[t]he degradation, destruction, or malfunction of systems that control this infrastructure could cause significant harm to the national and economic security of the United States." Utilities have had strong cyber security programs, and the Company is no different. However, by calling out cyber security of critical infrastructure as a national security issue, the Biden Administration is signaling that the Company, as an owner of critical infrastructure, needs to meet an even higher standard moving forward. The National Security Memo suggests that utilities need to have capabilities matching those of the top government agencies and contractors. This increased expectation will take time to develop and increased funding to achieve.

Third, as ordered by the Biden Administration, the CISA has established Cross Sector Cybersecurity Performance Goals, which signals the federal government's interest in gaining further assurances that owners and operators of critical infrastructure are meeting the expectations set forth in the memo. The Company expects this to include new, mandatory regulatory standards for natural gas.

**Q. Please describe how physical threats are increasing or evolving.**

A. Cyber security receives much of the national headlines because it is a relatively new risk and does not require physical proximity to execute an attack. However, physical security risks are still extremely relevant in the critical infrastructure space, and they continue to evolve. In the past year, multiple incidents have occurred at other gas utilities where

equipment was broken into and tampered with to the point of impacting gas delivery to customers. One utility reported that in December 2020, three separate gas sites were criminally vandalized, all at the same time, causing service disruption of over 3,500 customers for over three days with no gas during extremely cold temperatures. Furthermore, as gas becomes more of a target for environmental scrutiny, the Company may see more attempts to tamper with gas assets. One such example is an incident at a gas city gate where an individual used a stolen excavator to dig at night and nearly hit a gas line. Potential damage could have included thousands of customers without gas and over $10 million in repair costs.

**Q. What physical security challenges are you experiencing in securing critical infrastructure assets?**

A. The very nature of certain utility assets makes them very challenging to secure. Large assets such as a headquarters building or power plants can be secured using traditional physical security measures such as video cameras, card access, fencing, locks, keys, gates, and guards. The smaller, more distributed assets are significantly more challenging to secure. Placing guards at each asset would be untenable from a cost perspective. Technology solutions have historically been challenging because of limited feature sets (enhancements and capabilities) and network capacity at many of these remote locations. These limitations have led utilities to implement basic physical protections and accept remaining risk. Responses to security issues in these environments are, therefore, reactive and have become insufficient. These factors have made these critical assets soft targets to those who would do harm intentionally and attractive for opportunistic crimes. A shift to

a more proactive approach will minimize the impacts to customers from outage, safety, and cost perspectives.

Based upon recent pilot testing of solutions, there are now technology options capable of meeting these objectives. Where more traditional locks are the only practical option for items such as gates, control houses, and switches, the Company needs appropriate key management and locks made of materials that cannot readily be cut. Proactive approaches such as these will allow the Company to better protect its assets, increase safety, and reduce costs to customers.

**Q. What is changing in the regulatory landscape?**

A. The industry is expecting additional mandatory cyber security standards across the regulatory landscape. These include national reporting requirements for cyber security incidents and federal privacy legislation like what was enacted in Europe's General Data Protection Regulations, and legislation passed by many US states. There are also bills aimed at ransomware and critical infrastructure protections with various requirements.

On the privacy front, proposed legislation at the state and federal level would, if passed, impact management of customer data, necessitating standing up a formal customer data access, authentication, request, and provisioning program, a dispute resolution body and accompanying processes, as well as staffing for a thorough review, alignment, and continued operation of the Company's Customer Data Privacy Program. The Company continues to monitor the legislative landscape and proactively prepare with the implementation of privacy industry standards.

**Q. Has the work required to meet cyber security regulations and requirements increased in recent years?**

A. Yes. The current and emerging cyber-attack trends are evolving, and the number of threats is increasing in impact and sophistication as described earlier in my direct testimony.

As the security industry best practices evolve, new regulations are issued, and security requirements change, the IT Department must strive to keep pace with the time and expense of retrofitting existing infrastructure and applications to maintain compliance and an appropriate security posture.

**Q. Do cyber security requirements increase the frequency of IT patching and upgrades?**

A. Yes. To address changing security threats and vulnerabilities, vendors regularly release security fixes or "patches" to their products. The increased volume of threats to digital assets heightens the need to keep systems current, and timely security patching is a key control for any security program. Technology vendors establish timelines for versions of their product they no longer support or no longer provide security updates or patches for. Where the Company may have had more discretion in the past to defer upgrades, it now must ensure the appropriate upgrade or replacement frequency to meet security requirements. Patching analysis, patch application, and patch tracking activities are all considered Operations O&M expenses. The Company focuses on mitigating exposure to "Known Exploited Vulnerabilities" that the Cybersecurity and Infrastructure Security Agency has confirmed have been used to breach other companies' IT systems in the past. Reducing vulnerabilities requires timely patching, as well as upgrades and replacements to IT software and systems. The operational expenses related to security are important for the protection of Company assets and customer information.

**Q. How does the Company prioritize, balance, and manage the delivery of new capabilities that support the NGDP with operational work that includes meeting the security requirements described above?**

A. The Company's critical security and operational fixes are given priority over new capabilities to ensure safe, secure, and reliable operation of its digital assets. There is a high demand for new and enhanced technology capabilities across the Company. New investments are prioritized based on an evaluation of the benefits, costs, customer value, and necessity to Company goals through a series of reviews by cross-functional business teams. The highest-ranking projects are approved through the Company's budget and rate case processes and ultimately implemented.

**Q. What business categories has the Company defined in the IT Organization?**

A. The Company has defined the following business categories in the IT Department supporting the NGDP and customer offerings in this case: (1) Gas; (2) Electric & Gas Shared; (3) Corporate; (4) Customer; (5) IT/Digital Foundation; and (6) Security. These business categories are used to group investment spending in my exhibits to better connect rate case filings with the Company's plans. I will describe each of the business categories later in my testimony.

## OPERATIONS O&M EXPENSES—MAINTAIN AND OPERATE EXISTING ASSETS

**Q. What is Operations O&M expense for IT?**

A. The Company uses Operations O&M expense to provide the required level of operational support, reliability, and security for technology investments; maintenance for security facilities and systems to ensure system reliability, vulnerability assessments, and penetration tests; and fulfillment of all state and federal laws and regulations, perimeter

protection, guards, card access, cameras, executive protection, and investigative services. Operations O&M expenses include fixed and variable ongoing costs. Fixed costs include software vendor maintenance agreements, cloud subscription contracts, annual license contracts, and application or appliance support through managed services contracts. Software and cloud solution vendors typically increase these fixed costs on an annual basis. Variable costs include labor for equipment monitoring, break/fix activity, maintenance activity, disaster recovery, security improvements, software patching, and cloud usage costs. Operations costs also include physical security site assessments, vulnerability and penetration test remediation, additional guard support, system break/fix or maintenance activity, privacy program maturity, staffing support to meet emerging regulatory laws and regulations, and additional security system improvements. The activities associated with the fixed and variable costs are required to keep the Company's digital, information, and physical assets protected and performing at sufficient levels. The Company's customers benefit from the system stability and reliability that result from the activities funded by IT Operations O&M expense. These activities include emergency response, 24/7 billing, payment and usage services, contact center support, new service installations, and various other digital offerings, as well as physical and cyber security activities. Any unrecovered Operations O&M cannot be recovered in future rate case filings, which is why any disallowance could impede the Company's ability to maintain and secure its facilities and systems.

**Q. Please describe the operational work required to keep information and physical assets protected from cyber threats.**

A. There is a variety of operational work required to keep information and physical assets protected from cyber threats. First, regarding information assets, security tools must be kept functional when they are called on to protect the technology vital to serving the Company's customers. This technology includes software to collect logs, scan for vulnerabilities, detect intrusions, and provide antivirus and encryption services. Second, IT resiliency must be kept up to date ensuring backup data and redundant infrastructure are in place in the event of a cyber intrusion. Third, as described previously, systems must be patched on a regular basis in accordance with security requirements. Vendors regularly release security updates that must be tested to ensure these updates do not introduce negative impacts to Company-specific configurations when deployed. Fourth, as cyber security standards and requirements change, IT teams must implement the appropriate corresponding technical changes on existing systems to ensure Company assets remain secure. These requirements evolve and adapt as threats change in our environment. Security regularly reviews and updates physical and cyber security standards to maintain the appropriate posture with various industry frameworks, as well as compliance with cyber security regulations. This includes the technical requirements for IT to follow, which increases operational costs while continuing to best protect Company assets

Regarding physical assets and employee safety, first, routine assessments must be performed on all assets and facilities to ensure proper maintenance is performed and security protections are properly placed including perimeter protection, cameras, and card readers for facility access. Second, additional security support is needed for employees

when threats are present near field project work, storm restoration activities, or Company sponsored public events or forums. Third, additional security guard support is needed at facilities on an ad hoc basis (based on intelligence collected from facilities or crews, threats of violence against the Company, increased protest activity as seen in 2020, increased contractor traffic, and potential employee issues) to ensure the safety of employees and any visitors to the Company's facilities.

**Q. What value will customers receive for the projected test year O&M expenses?**

A. Customers are required to provide certain types of data as part of the service provided to them and want to know that the Company has a world class cyber security program working to protect data provided. Data breaches can cause identity theft, fraudulent charges, and time lost addressing related associated impacts. Beyond data breaches, customers also expect their data to be handled properly and only for the purposes intended. The discipline which addresses these concerns is broadly referred to as privacy, which is also within the corporate responsibility of the IT Department. In addition to data-related concerns, customers expect the Company's core services to be available 24/7. This is relevant on both the corporate and operational sides of the business. A ransomware attack would limit the service the Company can provide to customers and could lead to delays in resolving issues, obtaining service, outages, or significant safety concerns. An attack against the Company's operational systems could lead to a protracted loss of electricity or natural gas service for large portions of the service territory. Interruption of gas or electric service due to a cyberattack is not acceptable, and customers expect the utility to have all the protections necessary to ensure this does not occur.

**Q. Please describe Exhibit A-17 (SHB-1).**

A. Exhibit A-17 (SHB-1) is a Summary of Actual and Projected IT Operations O&M Expense for the Years 2023, 2024, 2025, and 12 months ending October 31, 2026. Page 1 summarizes the gas allocation of actual and projected IT Department operational expenses. Specifically:

- Column (a) provides the Operations O&M expense category;
- Column (b) identifies the total 2023 historical Operations O&M expense as $28,338,000;
- Column (c) identifies the total 2024 projected Operations O&M expense as $31,222,000;
- Column (d) identifies the total 2025 projected Operations O&M expense as $35,328,000;
- Column (e) identifies the total projected Operations O&M expense for the 2 months ending December 31, 2025 as $5,888,000;
- Column (f) identifies the total projected Operations O&M expense for the 10 months ending October 31, 2026 as $30,870,000;
- Column (g) identifies the total projected Operations O&M expense for the Test Year as $36,758,000; and
- "Labor" line items include employee labor, "Contracts" line items include hardware and software licenses and maintenance, and software subscriptions, "Material" line items include individual computer peripherals, tools, supplies, and replacements for failed components such as hard drives; and "Contractor" line items include staff augmentation, the Company's managed services contracts, and other contracted services. "Non-Labor Other" line items include employee training, wireless plans, and supplies.

Page 2 presents the amounts of the projected Operations O&M expenses that were developed by applying an inflation rate to the historical O&M expense. Specifically:

- Column (a) describes the categorical expense;
- Column (b) provides the historical Operations O&M expense;
- Column (c) provides the historical amount that an inflation rate was applied to;

- Columns (d), (f), and (h) provide the inflation increases for each respective period;
- Columns (e) and (g) provide the amount that an inflation rate was applied for 2024 and 2025, respectively;
- Column (i) includes amounts that were projected using other methods; and
- Column (j) provides the projected test year Operations O&M and is the sum of columns (b), (d), (f), (h), and (i).

**Q. Please describe the Other Adjustments in Exhibit A-17 (SHB-1), page 2, column (i).**

A. IT does not apply inflation in all categorical spend projections for Operations O&M expense. Labor is the only categorical spend projection that includes a merit increase based on the inflation rate. Inflation is not used to project any other categorical spend projections for Operations O&M expense. Future contract expenses reflect current commitments to increase payments under existing contracts, as well as the addition of new contracts needed for ongoing and new project work taking place before or during the test year. Material and Non-labor Other are projected based on historical spend and known adjustments for employee training needs, wireless plans, and supplies.

**Q. Please describe the projected IT Department Operations O&M expense for 2023 and 2024, as reflected in Exhibit A-17 (SHB-1).**

A. The Operations O&M expense in 2024 of $31,222,000 is projected to be an increase over 2023, which is $26,062,000 for IT and $5,160,000 for Security. The reason for the increase in 2024 is the result of organizational changes and the necessity to fund continued investment in programs to sustain and improve system reliability; to maintain, improve, and secure critical enterprise systems that support the Company's NGDP; and to prevent obsolescence and risk to business operations offset by cost-saving measures. Key drivers for the change from 2023 to 2024 for IT include: (1) net labor is reduced based on resource

reductions and move of network resources to Security ($1.0 million) offset by merit increases ($0.2 million), and transfer of website from Customer Operations and analytics resources from Customer Interactions and Operations Performance ($0.4 million); (2) net decrease in material and Non-Labor Other ($0.02 million); (3) increase in contractor ($0.95 million), which a portion ($0.45 million) is based on the transfer of website contractors costs from Customer Interactions; and (4) net increase in contracts for cloud subscriptions and license and maintenance agreements due to cost optimization efforts offset by annual increases ($1.23 million).

Key drivers for the change from 2023 to 2024 for Security include: (1) labor increased based on merit increases ($0.05 million) and increase for resources to support the Fusion Center and move of network resources from IT ($0.76 million); (2) net increase in contracts for cloud subscriptions and license and maintenance agreements ($.56 million) including reductions in MS Azure costs offset by an increase in cloud security platform; (3) net decrease in contractor ($0.37 million) based on reduction in Physical Security contractors; and (4) net increase in Non-Labor Other ($0.15 million) based on increase in training and business expense related to increase in resources.

**Q. Please describe the projected IT Department Operations O&M expense for 2025, as reflected in Exhibit A-17 (SHB-1).**

A. The Operations O&M expense in 2025 of $35,328,000 is projected to be an increase over 2024, which is $28,503,000 for IT and $6,825,000 for Security. The reason the Company is projecting an increase in 2025 is the necessity to fund continued investment in programs to sustain and improve customer reliability as the Company continues investing to maintain, improve, and secure critical enterprise systems and migrate applications to the

cloud. Known increases that are projected for IT include: (1) merit increase ($0.14 million) and backfill of resources supporting analytics ($0.59 million); (2) increase in cloud subscriptions and license and maintenance agreements ($1.5 million), including increase in support costs related to the Digital-Cloud Data and Analytics Platform project; (3) increase in material costs ($0.06 million) for circuits; and (4) increase in contractor costs ($0.17 million).

Key drivers for the change from 2024 to 2025 for Security include: (1) labor increase based on merit increases ($0.06 million) and increase for resources to support physical and cyber security ($0.37 million); (2) net increase in contracts for cloud subscriptions and license and maintenance agreements ($0.7 million); (3) net increase in contractor ($0.53 million) based on physical security contract resources; and (4) net decrease in Non-Labor Other ($0.01 million) based on projected training and business expense.

**Q. Please describe the projected IT Department Operations O&M expense for the test year, as reflected in Exhibit A-17 (SHB-1).**

A. The Operations O&M expense in the test year of $36,758,000 is projected to be an increase over 2025, which is $29,933,000 for IT and $6,825,000 for Security. The reason the Company is projecting an increase in the test year is the necessity to fund continued investment in programs to sustain and improve customer reliability as the Company continues investing to maintain, improve, and secure critical enterprise systems and migrate applications to the cloud. Known increases that are projected for IT include: (1) merit increase ($0.13 million) and (2) increase in cloud subscriptions and license and maintenance agreements ($1.4 million), including costs related to the Genesys Cloud

Migration, Standard Work Plan, and Digital-Hybrid Cloud and Data Center Migration projects.

Key drivers for the change from 2025 to the test year for Security include: (1) labor increase based on merit increases ($0.05 million) offset by resources efficiencies and (2) no change in contracts for cloud subscriptions and license and maintenance agreements due to planned cost optimization efforts to offset increases.

**Q. What does the Company's IT Operations O&M expense include?**

A. As described earlier, Operations O&M expense is made up of several components, such as labor, business expenses, material costs, contractor support, and vendor licensing and maintenance contracts.

"Labor" includes operational and governance costs for the IT employees who perform activities such as maintaining and supporting capital assets; disaster recovery and business continuity planning and testing; cyber security analysis and mitigation, such as security patching; and implementing performance measures to control IT costs and ensure compliance. These activities are variable and dependent on the outcome of risk analyses and other factors.

"Non-Labor Other" includes costs such as: business expense, employee training, wireless plans, and supplies. These costs are variable and dependent on needs of the organization.

"Material" includes costs such as individual computer peripherals, tools, supplies, and replacing failed components such as hard drives. These costs are variable and dependent on needs of the organization.

"Contractor" are costs of managed services and third parties that maintain and operate the Company's IT assets. Very similar to "Labor," the activities include system monitoring, system break/fix, disaster recovery activities, system analysis, and patching. The use of third parties to maintain and operate the Company's IT assets provides value by helping to control labor costs, offering up to 24/7/365 support, and providing increased access to specialized IT expertise.

Contracts, including "On-Premise Contracts" and "Cloud Subscriptions," reflect the Company's IT operations expenses for contracts with vendors who provide software and hardware licensing, support, and maintenance services so systems remain safe from mechanical and software failures and cyber intrusions. Lapses in licensing, support, or maintenance coverage caused by financial constraints would expose the Company to unfavorable security and operational risks or issues.

The Company relies heavily on vendors and their products to run the utility's digital systems and, as a result, the number of contracts and the corresponding costs are a significant piece of the total Operations costs.

**Q. Please explain why the Company is proposing to use more cloud/Software as a Service ("SaaS") based products.**

**A.** Cloud/SaaS based offerings are often the only option for certain technology services/vendors. For those that do also have on-premise options, many are stating that they will not be updated as quickly or may lack certain capabilities of their cloud counterparts. Vendors are making this shift for many reasons. First, as technology moves more and more to the cloud, security services need to adapt as well. Second, vendors can much more quickly build new capabilities for customers in a cloud-based scenario where

they control all the underlying hardware and infrastructure. Finally, the massive scale of security data requires much more flexibility which the cloud offers, and on-premise does not.

In addition to the industry drivers, there are benefits to both the Company and customers. More SaaS means fewer large capital outlays for large hardware purchases, vendor integrations, and less asset refresh cost. The Company anticipates fewer large capital projects in its future year planning for cyber security as capital requests have reduced, while physical security requests are increasing. Finally, using SaaS allows the Company to receive the best security capability available and allows vendors to adapt to changes much more quickly than on-premise solutions.

**Q. Please explain why the Company is proposing increased costs for third-party assessments and consultants.**

**A.** As scrutiny increases, Security Department teams have an increased need for third-party validation to both ensure appropriate security controls are in place, but also to inform various stakeholder groups. Outside expertise is also critical to ensure internal teams see broader perspectives and understand leading practices. The dollars requested will be used in a variety of ways including external penetration testing, maturity assessments, incident exercises, research, coaching, and consulting.

**Q. Is the method used by the Company to project IT Operations O&M an accurate and prudent approach?**

A. Yes, the method used by the Company to project IT Operations O&M expenses in Exhibit A-17 (SHB-1) is the most accurate method. The Company's approach uses a detailed analysis of known fixed and variable expenses for the test year. These include increases

that result from new investments and assets tied to growth in digital, new cyber security regulations and requirements, and outcomes of cost optimization efforts. By using known and expected expenses that are coupled with the evolving digital landscape, the projection is the best representation of the Company's required IT Operations O&M expenses in the test year.

**Q. Please describe Exhibit A-18 (SHB-2).**

A. Exhibit A-18 (SHB-2) is the IT Cloud Computing Prepaid Balance for Gas and Common operations for the historical 13 months ending June 30, 2024 and the projected 13 months ending October 31, 2026. It provides a summary of the gas allocation of actual and projected IT Department operational expenditures. Specifically:

- Column (a) provides the prepaid balance category;
- Columns (b) through (n) provide each month's ending IT cloud computing prepaid balance; and
- Column (o) provides the 13-month average of columns (b) through (n).

**Q. Please describe the purpose of Exhibit A-18 (SHB-2).**

A. The move to utilize cloud computing is resulting in an increase in prepaids associated with cloud computing subscriptions and implementation costs. The Company has identified cloud computing as a viable alternative for several technology solutions, which are described in more detail for the associated projects below. To support the adoption of cloud computing, the Company is adjusting working capital to reflect projections for cloud computing subscriptions and implementation costs. Cloud computing costs are projected based on existing cloud computing subscription agreements plus projected new cloud computing costs based on planned implementations. This working capital adjustment is provided by Company witness Heather L. Rayl on Exhibit A-12 (HLR-34), Schedule B-4.

**INVESTMENTS O&M EXPENSES—MAINTAIN A CURRENT SYSTEM AND BUILD NEW CAPABILITIES**

**Q. How is Investments O&M for IT used by the Company?**

A. Investments O&M is used by the Company to fund the O&M portion of upgrade projects, asset refresh projects, and technology investments that are needed to provide the new capabilities for internal business units, security operations, and customers.

**Q. Please describe the importance of upgrading IT systems for cyber security requirements and operational stability.**

A. Upgrading applications, appliances, operating systems, database management systems, and security devices, such as cameras and card readers, are essential to delivering safe, reliable, and affordable gas to the Company's customers. Implementing current versions of technology enables the Company to operate secure and stable systems, remediate security vulnerabilities, keep customer and company data secure, maintain vendor support, address defects that impair stability and functionality, and address version interdependencies and compatibility between systems.

**Q. What cyber security risks could occur if the Company does not keep its systems upgraded?**

A. Technologies and security devices that are not upgraded are often no longer supported by vendors, which increases security risk as well as system operations risk, as security patches are regularly released by vendors based on known vulnerabilities. Security patches are typically not produced for products no longer supported by the vendor, referred to as end-of-life products; therefore, an end-of-life product may have known vulnerabilities and no method to remediate the risk. This increases the risk of a significant cyber event impacting Company operations, data, and services to its customers.

**Q. How does the Company determine which systems need to be upgraded?**

A. While the Company's preferred upgrade strategy is to stay, at most, one version behind the vendor's currently available version, the Company considers multiple factors to determine when upgrades are needed. These include application criticality to business and customer operations, severity of existing vulnerabilities and operational risk, operational impacts of performing the upgrade, ability to defer, resource availability, organizational change impact, and cost. Deferring an application upgrade for too long has the potential to increase the overall cost of the upgrade since the larger number of differences between versions generally adds complexity and cost to an upgrade effort.

Until recently, the Company has lacked funds to maintain and keep systems current. This led to technical obsolescence, and the Company is in a position of playing catch-up, adding risk that a significant cyber security or technical issue might not be remediated or mitigated, which would cause direct impact to Company operations, its customers, or both. The Company prioritizes operational support over new investments when resources are limited, thus putting the NGDP at risk when important systems cannot be kept current with available resources.

**Q. Please describe Exhibit A-19 (SHB-3).**

A. Exhibit A-19 (SHB-3) is a Summary of Actual and Projected IT Investments O&M Expenses for the Years 2023, 2024, 2025, and the 12 months ending October 31, 2026. Page 1 provides a summary of the gas allocation of actual and projected IT Department Investments O&M expenditures. Specifically:

- Column (a) provides the Investments O&M expense category;
- Column (b) identifies the 2023 historical Investments O&M expense as $4,912,000;

- Column (c) identifies the 2024 projected Investments O&M expense as $6,315,000;
- Column (d) identifies the 2025 projected Investments O&M expense as $10,019,000;
- Column (e) identifies the 2 months ending December 31, 2025 projected Investments O&M expense as $3,200,000;
- Column (f) identifies the 10 months ending October 31, 2026 projected Investments O&M expense as $14,748,000;
- Column (g) identifies the Test Year projected Investments O&M expense as $17,948,000;
- For Investments Planning expense, "Labor" line items include employee labor, and "Contracts" line items include hardware and software licenses and maintenance, staff augmentation, and other contracted services; and
- For Investments expense, "Labor" line items include employee labor, "Software" line items include software licenses and maintenance contracts, "Material" line items include hardware purchases and maintenance contracts, "Contractor Costs" line items include staff augmentation, managed services, and other contracted services, "Non-Labor Overhead" line items include overheads, and "Non-Labor Others" line items include pension expense, administrative/general expense, Allowance for Funds Used During Construction ("AFUDC"), and business expenses.

Page 2 presents the amounts of the projected Investments O&M expenses that were developed by applying an inflation rate to historical O&M expense. Specifically:

- Column (a) is a description of the categorical expense;
- Column (b) provides the historical Investments O&M expense;
- Column (c) provides the historical amount that an inflation rate was applied to;
- Columns (d), (f), and (h) provide the inflation increases for each respective period;
- Columns (e) and (g) provide the amount that an inflation rate was applied for 2024 and 2025, respectively;
- Column (i) includes amounts that were projected using other methods; and

- Column (j) provides the projected test year Investments O&M and is the sum of columns (b), (d), (f), (h), and (i).

**Q. Please describe the Other Adjustments indicated in Exhibit A-19 (SHB-3), page 2.**

A. IT does not apply inflation for categorical spend projections for Investments Planning expense. The investments planning projection is adjusted by $77,000 for an anticipated decrease in the test year for investments planning activities that directly support business case development and cost estimate refinement for projects that support the NGDP, and other Company long-term plans. Inflation is also not used to project future Investments O&M expense. The other adjustments for Investments O&M expense of $13,113,000 are based solely on expected project costs for the test year as compared to the historical period, as detailed later in my testimony and in Confidential Exhibit A-20 (SHB-5).

**Q. Are the preliminary project stage activities that must be part of Investments O&M expense per Financial Accounting Standards Board ("FASB") guidelines important in technology investment projects?**

A. Yes. The preliminary project stage activities are essential to ensure the Company makes prudent investments in technology that benefit customers. The activities cover much of the work included in the Company's investment planning for IT projects. Investment planning activities gather information that is required by the MPSC in Case No. U-18238 as part of the rate case filing requirements for IT and OT.

**Q. Is the investment planning activity speculative?**

A. No, it is not speculative. Investment planning is a pragmatic process that results in documented technology investment details. The process documentation includes: a project description and description of system functionality, project timelines including expected implementation date and spending plans, project benefits, a description of alternatives

considered and rationale behind the decision, and cost benefit ratio, which were required by the MPSC in Case No. U-18238. Other important activities of investment planning are: identifying high-level business requirements, determining whether the functionality needed is already present in the Company's IT environment, identifying performance and security requirements, working with software vendors and cloud solution providers to demonstrate the effectiveness and security of their products and services, and developing the business case with project costs and benefits to confirm whether a proposed project should be approved for development and implementation.

During this phase, the Company spends the necessary time on up-front planning and due diligence for the technology investment. As an example, to maintain the reliability and safety of the Company's field dispatch communications, the Company needed to replace the aging core radio system infrastructure. The Company spent time on up-front planning for the 800 MHz Modernization upgrade project to build and confirm the scope, estimates, and alternatives. Investment planning is time needed to better understand the vendor solution and organize the work. Investment planning is based on key outcomes and fact-gathering to ensure it is not merely speculative.

**Q. Should the Company be allowed recovery for the planning expense tied to technology investments?**

A. Yes, the Company should be allowed recovery for this up-front planning activity. This work is required by the MPSC for technology investment, and for good reason. It is in the best interest of the Company's customers that the Company perform these investment planning activities to ensure potential investments provide sufficient value to justify the expense. The Company considers many ideas, but not all are feasible or even warrant

investment planning. Critical as these expenses are, the Company does strive to minimize planning expenses; only those potential investments with the highest expected value even reach the planning phase. This reasonable and prudent work has associated costs and is required by the MPSC for technology investment planning. Accordingly, the Company should receive recovery for this required expense.

**Q. Would it be more accurate to use a different method to project the Company's IT Investments O&M expenses?**

A. No. The level of IT Investments O&M expense is closely coupled with the projected capital expenditures for IT and the upgrade and replacement cycles for existing assets. To fully and appropriately execute plans to spend the capital that has been deemed prudent to deliver value to its customers, keep its technology assets as current and secure as reasonably possible, and adhere to the FASB ASC 350-40 guideline for project activities that should be expensed, the Company requires the specific and forward-looking IT Investments O&M requested for the Test Year period. Other methods such as a historical average, which would be lower than the requested amount in this case, would not allow the Company to keep its systems current for security and reliability and make necessary and prudent capital expenditures to achieve the outcomes of the NGDP and improve customer service. Additionally, the Company projects an increase in cloud solutions, which often have a higher level of Investments O&M than projects in earlier years.

**INVESTMENTS CAPITAL EXPENDITURES**

**Q. Please describe the capital expenditures shown on Exhibit A-12 (SHB-4), Schedule B-5.1.**

A. Exhibit A-12 (SHB-4), Schedule B-5.1, identifies the gas allocation of actual and projected capital expenditures to procure, install, and implement the software and infrastructure described in my testimony to meet business requirements. Specifically:

- Column (a) provides the business category designation for the capital expenditures:
  - Corporate;
  - Customer;
  - Electric & Gas Shared;
  - Gas;
  - IT/Digital Foundation; and
  - Security.
- Page 1 of 2
  - Column (b) identifies the 2023 historical year capital expenditures as $27,620,000;
  - Column (c) identifies the 12 months ending December 31, 2024 projected bridge year capital expenditures as $32,046,000;
  - Column (d) identifies the 10 months ending October 31, 2025 projected bridge year capital expenditures as $28,724,000;
  - Column (e) identifies the 22 months ending October 31, 2025 projected bridge year capital expenditures as $60,770,000; and
  - Column (f) identifies the 12 months ending October 31, 2026 projected test year capital expenditures of $50,963,000.
- Page 2 of 2
  - Column (b) identifies the 10 months ending October 31, 2024 capital expenditures as $27,910,000;

- Column (c) identifies the 12 months ending October 31, 2025 capital expenditures as $32,860,000;
- Column (d) identifies the 12 months ending October 31, 2026 projected bridge year capital expenditures as $50,693,000; and
- Column (e) identifies the 34 months ending October 31, 2026 projected bridge year capital expenditures as $111,464,000.

- For Investments expenditures, "Labor" line items include employee labor, "Software" line items include software licenses and maintenance contracts, "Material" line items include hardware purchases and maintenance contracts, "Contractor" line items include staff augmentation, managed services, and other contracted services, "Non-Labor Overhead" line items include overheads, and "Non-Labor Others" line items include pension expense, administrative/general expense, AFUDC, and business expenses.

**Q. Please explain Confidential Exhibit A-20 (SHB-5).**

A. Confidential Exhibit A-20 (SHB-5) identifies the gas allocation of projected capital and O&M expenditures to procure, install, and implement the software and infrastructure requested in my testimony to meet business requirements. Both O&M and capital are required to complete the projects included in the test year. This exhibit provides details regarding all projects included in this rate case filing for the IT Department. Specifically, within this exhibit:

- Column (a) provides the year of spending for this line item project;
- Column (b) identifies the project name associated with each line item capital expenditure for the applicable year;
- Column (c) identifies the Federal Energy Regulatory Commission ("FERC") category relative to the line item project's asset type;
- Column (d) identifies the Business Category of the project;
- Column (e) provides a synopsis of the project, including the project description and information on project scope, functionality, and benefits;
- Column (f) identifies the project's start date;
- Column (g) identifies the project's end date;

- Column (h) provides the project's cost/benefit ratio;
- Column (i) provides the total Company expected project capital costs;
- Column (j) provides the total Company expected projected O&M costs;
- Column (k) identifies the project's estimate type;
- Column (l) provides the project's gas portion total capital expenditure for the applicable year;
- Columns (m) through (r) provide the details of categorical spend that sum to the total line item Project Capital Spend for the applicable year broken down by:
    - Software costs (m);
    - Material costs (n);
    - Labor costs (o);
    - Contractor costs (p);
    - Non-Labor Overhead costs (q); and
    - Non-Labor Other costs (r).
- Column (s) provides the project's gas portion total O&M spend for the applicable year; and
- Columns (t) through (y) provide the details of categorical spend that sum to the total line item Project O&M Spend for the applicable year by the following categories:
    - Software costs (t);
    - Material costs (u);
    - Labor costs (v);
    - Contractor costs (w);
    - Non-Labor Overhead costs (x); and
    - Non-Labor Other costs (y).

**Q. Please explain the difference between Exhibit A-12 (SHB-4), Schedule B-5.1, and Confidential Exhibit A-20 (SHB-5).**

A. Exhibit A-12 (SHB-4), Schedule B-5.1, and Confidential Exhibit A-20 (SHB-5) are both capital expenditure exhibits that display different views to address the different requirements of the MPSC, as well as the IT Department, as outlined below:

- Exhibit A-12 (SHB-4), Schedule B-5.1, is a high-level summary of capital expenditures by year, by business category or product line, and by categorical spend; and
- Confidential Exhibit A-20 (SHB-5) is a more comprehensive exhibit displaying the detail of each project over the four-year time periods of 2023, 2024, 2025, and 2026.

**Q. Please explain Confidential Exhibit A-21 (SHB-6).**

A. Confidential Exhibit A-21 (SHB-6) is an Executive Summary report generated from the Company's internal BPS. This exhibit provides the approved business case information for each IT project in Confidential Exhibit A-20 (SHB-5). Exhibit A-12 (SHB-4), Schedule B-5.1, addresses the Commission's interest in:

- projects having approved business cases;
- total project cost for multi-year projects;
- associated hard savings; and
- benefit-cost overall value utilized by the Company.

This exhibit provides the same view the Company uses internally to review the Executive Summary of each business case approved to be included in the test year. It also outlines the total Company cost of ownership of each project, including the initial one-time project investment which could fund work occurring over multiple years, and the projected ongoing support costs after project implementation. Additionally, it identifies recurring

hard savings over the life of the investment and provides the cost benefit ratio with a zero breakeven point calculated by the Company's internal BPS. Specifically, within each section of this exhibit:

- Header Information section includes project name, the date the report was generated, and BPS identification number. Specifically:
  - Project Name is the name of the project that indicates the project objective;
  - Report Pulled is the date the Executive Summary report was generated from BPS; and
  - Item ID is the unique identifier from BPS.
- Basic Information section includes work category, work type, alias, brief description, portfolio, organization, business unit, and department. Specifically:
  - Work Category identifies classification of work and activities based on the Company methodology;
  - Work Type identifies "project" as the type of work for all IT investments;
  - Alias identifies historical project names for reference;
  - Description identifies a brief description of the project's intent and the expected outcome;
  - Portfolio identifies the financial planning portfolio for whom the work will be performed;
  - Org identifies the financial planning organization for whom the work will be budgeted;
  - Business Unit identifies the business unit for whom the work will be budgeted; and
  - Dept identifies the department for whom the work will be budgeted.
- Work Objectives includes a synopsis of the project, including the problem statement, objectives, information on project scope, functionality, and benefits, and alternatives considered. Specifically:

- Problem Statement provides an explanation of the problem(s) the work addresses;
- Objectives provides information about the business value the project will deliver;
- Scope describes the high-level business functionality and a list of high-level project deliverables; and
- Alternatives provide a summary of each of the alternatives considered, why each alternative was not selected and the rationale behind the alternative selected.

- Dates section includes the projected implementation phase start or end dates for projects, with the exception of the Annual Spend Programs such as Asset Refresh Programs, Application Currency, and Enhancements. Specifically:
  - Initiation is the start date of the project Plan phase;
  - Project Plan & Scope Definition is the end date of the project Plan phase;
  - Final Engineering, Planning & Design is the end date of the Design phase;
  - Execution is the end date of the Execute phase;
  - In-Service/Go-Live is the project's implementation date; and
  - Closeout is the end date of the Close phase.

- Funding Summary section includes a Total Company summary and detailed breakdown of projected categorical spend by year for each project. Specifically:
  - Summary of the Total Cost of Ownership of projected capital expenditures and O&M expense for each project, including ongoing maintenance, where:
    - Cap+COR is the total of all the capital expenditures; and
    - O&M is the total of all the O&M expense for the project implementation and ongoing maintenance.
  - Total Project Cost contains a detailed categorical breakdown for projected capital expenditures and O&M expense for each project, excluding ongoing maintenance, where:
    - Labor includes the internal staffing costs for project implementation;

- Outside Services includes the external labor and services for project implementation;
- Business Expenses/Overheads includes costs for items such as training, travel, lodging, and meals and Loadings & Allocations for Corporate Overheads and AFUDC;
- Employee Benefits includes costs for employee benefits;
- Material includes costs for hardware purchases;
- Licenses, Permits & Fees includes costs for software and hardware licenses and maintenance; and
- Other includes miscellaneous costs.

- Value & Impacts Summary Section provides a summary of the projected cost and benefits, risk and other value associated with a project for Capital expenditures and O&M expense, including ongoing maintenance, where:
  - For purposes of O&M:
    - Reduction includes the hard O&M savings;
    - Initial includes the implementation and ongoing maintenance costs;
    - Incremental includes any other O&M costs; and
    - Net is the difference of the reduction, initial, and incremental O&M costs.
  - For purposes of Cap+COR:
    - Reduction includes any hard capital savings;
    - Initial includes the implementation costs;
    - Incremental includes any other capital costs; and
    - Net is the difference of the reduction, initial, and incremental capital costs.
  - For purposes of Revenue:
    - Reduction includes any expenses;
    - Initial includes implementation revenue;

- Incremental includes any increase in revenue; and
- Net is the difference of the reduction, initial, and incremental revenue.

o For purposes of determining financial value of a project, the B/C Ratio (Overall), as shown in the figure below, is the net present value of the change in O&M, plus change in Capital, plus change in Revenue, divided by Total Cost of Ownership set with a breakeven point at zero.

$$\textbf{\textit{Financial Value}}\ (F_{Overall}) = \frac{\sum B}{\sum C} - 1$$

Where
$B$ = Benefits
$C$ = Total Costs

o For purposes of identifying risk:

- Type of Corporate Risk;
- Level of impact;
- Likelihood of risk; and
- Description of risk.

o And, for purposes of identifying other value:

- Type of other value; and
- Description of other value.

**Q. Please explain the breakeven point for the Company's B/C Ratio (Overall).**

A. Using the Company's internal BPS B/C Ratio (Overall), the breakeven point is equal to zero where financial benefits and total costs are equal. If the result of the calculation is greater than zero, financial benefits exceed costs. If the result is less than zero, total cost of ownership exceeds the financial benefit.

**Q. Does the cost summary component in the Company's B/C Ratio (Overall) use the total one-time project cost, or the total one-time project cost plus the ongoing support costs?**

A. The Company's internal BPS B/C Ratio (Overall) cost summary denominator uses total one-time project cost plus the ongoing support costs.

**Q. Where is the total Company project cost number distinguished from the total Company project cost number that includes ongoing maintenance cost?**

A. The total one-time Company project cost is the Total Project Cost at the bottom right corner of the Funding Summary Section of Confidential Exhibit A-21 (SHB-6). This section of the Funding Summary section, starting with Labor, lists the breakdown of different cost categories for this investment. The total projected Company cost of ownership, including annual ongoing support costs, is the Total Cost of Ownership value on the right of the Funding Summary Section.

## INVESTMENT IDENTIFICATION, PRIORITIZATION, APPROVAL, AND PROJECT PLANNING

**Q. Please describe how technology projects are initiated, prioritized, and approved within the Company.**

A. The initiation of a technology project begins with identification of a need for new or updated technology to meet the requirements of the Company's customers, including technology that customers interact with directly, and technology that sustains and improves reliability in service of customers. For example, IT collaborated closely with Company witnesses and representatives from the gas departments to identify technology projects and foundational digital investments necessary to enable the NGDP. The joint teams prepared business cases for each of the projects utilizing standard format and content.

After sponsor approval, individual projects are prioritized based on an evaluation of the benefits, costs, customer value, and necessity to Company goals through a series of reviews by cross-functional business teams. The highest-ranking projects within the level of IT funding approved through the Company's budget and rate case process are selected for implementation and approved by each business area, followed by approval of the overall IT budget by the senior officer team. Due to the rapid pace of technology change and quickly changing business conditions, emergent projects are identified and vetted through IT and the affected internal business areas throughout the year as business objectives, Company goals, and customer needs and expectations evolve.

**Q. Please explain how IT's investment forecasts evolve over the course of project planning and implementation.**

A. IT's investment forecasts begin with a ROM estimate. The Company uses the term "ROM" to characterize an initial estimate that includes research, analysis, and a business case. ROM estimates are typically determined by technology and subject matter experts inside and outside the Company in comparison to historical actual costs for similar projects. The purpose of the ROM estimate is to determine whether the estimated costs justify the value provided by the new capabilities without spending an inordinate amount of investment planning O&M developing the bottom-up estimate. From that point, investment forecasting depends on the method used to deliver the intended solution. In the case of Agile delivery, the project team targets the delivery of the highest business value capabilities within the projected funding. In the case of traditional waterfall delivery, once the formal design of a project has concluded, IT subject matter experts perform a detailed definitive estimate for execution. Factors may arise during project execution, such as

resource needs, delays in receiving materials, changes in project schedule that shift spending between years, and changes in project scope or complexity that results in funding needs being lower or higher than initially estimated through the ROM process.

**Q. Do the Company's total IT capital projections reflect a 20% reduction for those projects whose projections are based on a ROM?**

A. Yes. Despite ROM cost-cutting concerns, the total capital projections include a 20% reduction for those projects whose projections are based on a ROM. In order to prevent over recovery, a 20% ROM adjustment is calculated by Business Category for those projects with a ROM estimate with the expectation that the full costs of approved projects may be recovered in a future rate case. These reductions are included in the table below and further reflected in Confidential Exhibit A-20 (SHB-5). Additionally, the ROM Adjusted Test Year Capital is identified for each project later in my testimony.

| Year | Projected | Adjusted Projected (20% ROM Adjustment) |
|---|---|---|
| 2023 | $27,620,499 | $27,620,499 |
| 2024 | $32,101,841 | $32,046,466 |
| 2025 | $41,044,512 | $38,330,711 |
| 2026 | $57,459,318 | $49,303,979 |
| Test Year | $57,941,869 | $50,693,453 |

**Q. Was this 20% reduction to capital expenditures for all ROM estimate projects a reaction to the Commission's decision on page 128 of its December 22, 2021 Order in Case No. U-20963?**

A. Yes, in Case No. U-20963, MPSC Staff ("Staff") recommended a 20% disallowance for ROM estimates (Case No. U-20963, 6 TR 4081), and the Commission agreed saying that the ROM estimates are akin to contingency costs. The 20% reduction to capital expenditures for all ROM estimate projects used by IT in this case differentiates the

Company's ROM estimates from the ROM estimates it used in Case No. U-20963 (in fact, the 20% reduction reflects Staff's position in Case No. U-20963) and further shows that the ROM estimate projects do not include contingency. Contingency is a project management best practice to add and reserve a percentage of a project's budget for unforeseen circumstances encountered during the course of the project. Due to previous disallowances, IT estimates do not include contingency. The ROM estimate is (1) intended to cover the full cost of the project rather than a portion, (2) built to address specific scope rather than unforeseen events, and (3) is calculated by technology and subject matter experts for a specific project whereas contingency is a percentage allocation based on an industry percentage value and/or project risk rating.

**Q. Which exhibits contain the estimate breakdown for each project?**

A. Confidential Exhibit A-20 (SHB-5) contains each project's gas allocation spend for the applicable year broken down by software, materials, labor, contractor costs, and non-labor overhead and non-labor other costs. Confidential Exhibit A-21 (SHB-6) contains Company spend for each project in the historical, bridge, and test years, broken down by year, that shows:

- Staffing;
- Outside Services;
- Business Expenses/Other;
- Employee Benefits;
- Materials, Licenses, Permit & Fees; and
- Other.

**Q. Do all the projects included in the test year have project plans and schedules?**

A. All projects included in the test year will have project plans and target dates at levels commensurate with their current phase. Some projects are continuing from an earlier period into the test year and have more definitive project plans for delivery. When the budget is released to a project to begin the official Plan phase, the product team will develop a more specific project plan that includes progressively more detail as the project moves through its different phases. In the case of projects executed using Agile methods, a high-level plan will be developed at the start of the project that includes an estimated number of time-bound delivery cycles, or sprints, in which the targeted scope backlog will be delivered.

**INVESTMENT PROJECTS**

**Q. Please provide a description of the various IT investment business categories or product lines to be highlighted in testimony.**

A. Costs, descriptions, benefits, alternatives, and other relevant project information for each individual project can be found in Confidential Exhibits A-20 (SHB-5) and A-21 (SHB-6). The IT investment projects are grouped into the following areas for explanation in testimony:

- **Gas and Electric & Gas Shared** projects that enable the NGDP for Asset Management; Work Management; System Automation and Control, Security and Privacy; and Advanced Analytics that are necessary components to enable the Company to be an energy partner that customers, regulators, and the people of Michigan can count on to provide safe, affordable, reliable, and clean gas system;

- **Customer** projects that are necessary to enable the Company to comply with regulatory billing changes, improve billing functionality, implement capabilities to assist low-income customers with energy assistance, increase the Company's ability to serve customers within the channel of their choice, and

engage customers to enroll in demand response and energy waste reduction programs;

- **Corporate** projects that support internal departments of the Company are crucial to running an efficient business such as Treasury; Tax; Legal; HR, also known as People and Culture; Governmental, Regulatory and Public Affairs; Supply Chain and Facilities, also known as Operations Support; Finance; and Risk & Compliance;

- **IT/Digital Foundation** projects create the technology platforms, tools, processes, and frameworks that are required to enable NGDP, and customer service outcomes. This includes ARP, application currency, upgrade and replacements, and digital and foundation capabilities projects; and

- **Security** projects are necessary to deter threats prior to impacting the Company, detect when malicious activity does occur, recover quickly with minimal effect if or when a threat occurs, comply with all governmental and industry regulations, and enable the Company and its customers outcomes

**IT Projects Enabling Other Areas**

**Q. Please explain the Gas and Electric & Gas Shared projects enabling NGDP.**

A. Below are the projects enabling NGDP. Investments in digital capabilities are essential to achieving the Company's NGDP business plan and Work Management improvements. A synopsis of each project with its value is included in the testimony of other Company witnesses, as indicated below.

| Project | Projected Test Year Capital | ROM Adjusted Test Year Capital | Test Year O&M | Witness |
|---|---|---|---|---|
| Compression Air Permit and Compliance Digitalization | $385,213 | $308,170 | $38,105 | Timothy K. Joyce |
| Gas Distribution Probabilistic Risk Model | $1,271,603 | $1,017,283 | $11,033 | Lincoln D. Warriner |
| Gas SCADA Software Solution | $1,339,822 | $1,071,858 | $171,959 | Lincoln D. Warriner |
| Gas T&D Historian | $127,269 | $101,815 | $37,450 | Lincoln D. Warriner |
| Tracking and Traceability | $6,619,263 | $5,295,411 | $508,607 | Lincoln D. Warriner |
| Standard Work Plan | $48,320 | $38,656 | $98,400 | James P. Pnacek |

Additionally, the Application Currency-Gas-O&M and Capital, Application Currency-Electric & Gas Shared-O&M and Capital, Product Family Enhancements-Gas-O&M and

Capital, and Product Family Enhancements-Electric & Gas Shared-O&M and Capital will be discussed later in my testimony.

**Q. Are there any Gas projects with variances from the previous Case No. U-21490 that you would like to discuss?**

A. Yes. The following Gas project is addressed below.

- Gas SCADA Software Solution

**Q. Please recap the Gas SCADA Software Solution project.**

A. The Gas SCADA Software Solution project will replace the current Gas SCADA Software with a more standardized software package enabling the Company to more efficiently meet Federal and MPSC requirements.

- **Problem Statement:** The current Gas SCADA software solution was originally implemented in 2000 and was based on the gas system requirements at that time. While the solution has been maintained since its implementation, the Company's gas system has outgrown the current capabilities. As the solution ages, there is increased effort required to address obsolete application and database software architecture, and enhancements to the system are limited. To address the capability gaps, custom interim fixes and integrations have been developed where each requires maintenance and support. This environment adds complexity and cost to solution upgrades and troubleshooting issues. The current Gas SCADA solution will limit the ability to invest in digital solutions for increased system health monitoring and preventative maintenance capabilities due to the complexity to integrate these future capabilities with it.

- **Objectives:** The project will add value by: (1) reducing risk of non-compliance by improving the ability to document and follow State and Federal requirements, improving customer safety; (2) improving efficiency and reliability when performing routine software upgrades, because standard out-of-the-box software has less risk of breaking during upgrades, as opposed to more custom-coded software; (3) reducing maintenance costs due to fewer individual software programs and less custom code; (4) improving Gas Control management capabilities that support the Federal and MPSC requirements for gas pipeline and Gas Distribution companies; (5) improving reliability by using proven gas industry standardized software with configuration features, rather than a fully customized system that has the possibility of being impacted by the next version update; (6) purchasing standard, out-of-the-box software that meets a high percentage of requirements and avoids multiple custom applications and specially coded programs to achieve results; and (7) providing

a basis for capturing data required for use in computer-based preventative maintenance programs and more predictive technologies. In addition, implementing industry-specific software helps the collective gas industry users to encourage the vendor development of future version enhancements, which adds more value to gas industry users. The comprehensive Gas SCADA system is used to monitor and control the operating conditions of the transmission and distribution gas systems. The Gas SCADA system includes remote terminal units (RTUs), field devices (i.e. valves, meters, odorizers), and computers running SCADA software. This scope covers the Gas SCADA software solution only.

- **Scope:** The project scope includes the following: (1) significant planning, including consulting assistance, to define the implementation strategy for the effort, given the magnitude of the technology effort; (2) selection and implementation of a new Gas SCADA software solution; (3) planning of a phased rollout of new hardware and software; and (4) retirement and decommissioning of the legacy gas SCADA solution and equipment once the new system is fully tested and operational.

- **Alternatives:** Alternatives considered include: (1) continue to maintain the current solution, at the risk of increasing reliability issues that result in controlling and monitoring the Company's gas system; (2) invest in enhancing the existing Gas SCADA software solution which would introduce additional custom development and more specialized functions that may not be supported in future vendor releases; and (3) replace the solution with a Gas SCADA software solution that meets requirements to support the NGDP. Alternative three has been selected to ensure sustainability for this critical solution. The current legacy system is operating at well beyond its original design specification, so the potential points of failure are not fully known or understood. If the SCADA project is not completed, the legacy system could become unstable and impact Gas Control's ability to operate and monitor real-time system conditions, maintain safe operations, and comply with regulatory requirements. It could also impact the ability to commission new facilities which require remote monitoring or control or cause the need for 24/7 manual field monitoring of certain facilities.

**Q. What were the total projected capital expenditures for the Gas SCADA Software Solution project in Case No. U-21490?**

A. The Case No. U-21490 projected capital expenditures by year and cost category for the Gas SCADA Software Solution project are in the table provided below.

| Gas SCADA Software Solution | | | |
|---|---|---|---|
| Case No. U-21490 | | | |
| Cost Category | Total Company Capital | Gas Allocation Capital | U-21490 Reference |
| **2023 Projected** | | | |
| Software | $400,000 | $400,000 | A-22 (SHB-5), line 170, column l |
| Material | $200,000 | $200,000 | A-22 (SHB-5), line 170, column m |
| Labor | $353,273 | $353,273 | A-22 (SHB-5), line 170, column n |
| Contractor Costs | $1,133,000 | $1,133,000 | A-22 (SHB-5), line 170, column o |
| Overhead & Other Costs | $426,345 | $426,345 | A-22 (SHB-5), line 170, column p |
| **Total 2023 Projected** | **$2,512,618** | **$2,512,618** | A-22 (SHB-5), line 170, column k |
| **2024 Projected** | | | |
| Software | $985,282 | $985,282 | A-22 (SHB-5), line 247, column l |
| Material | $1,147,152 | $1,147,152 | A-22 (SHB-5), line 247, column m |
| Labor | $901,900 | $901,900 | A-22 (SHB-5), line 247, column n |
| Contractor Costs | $2,144,475 | $2,144,475 | A-22 (SHB-5), line 247, column o |
| Overhead & Other Costs | $1,006,673 | $1,006,673 | A-22 (SHB-5), line 247, column p |
| **Total 2024 Projected** | **$6,185,482** | **$6,185,482** | A-22 (SHB-5), line 247, column k |
| **2025 Projected** | | | |
| Software | $212,500 | $212,500 | A-22 (SHB-5), line 317, column l |
| Material | $0 | $0 | A-22 (SHB-5), line 317, column m |
| Labor | $653,720 | $653,720 | A-22 (SHB-5), line 317, column n |
| Contractor Costs | $1,357,238 | $1,357,238 | A-22 (SHB-5), line 317, column o |
| Overhead & Other Costs | $569,642 | $569,642 | A-22 (SHB-5), line 317, column p |
| **Total 2025 Projected** | **$2,793,100** | **$2,793,100** | A-22 (SHB-5), line 317, column k |

| | | | |
|---|---|---|---|
| **Total Projected** | | | |
| Software | $1,597,782 | $1,597,782 | |
| Material | $1,347,152 | $1,347,152 | |
| Labor | $1,908,893 | $1,908,893 | |
| Contractor Costs | $4,634,713 | $4,634,713 | |
| Overhead & Other Costs | $2,002,660 | $2,002,660 | |
| **Total Projected** | **$11,491,200** | **$11,491,200** | |

**Q. What are the current projected total project costs broken down by year for the Gas SCADA Software Solution project?**

A. The total project costs broken down by year for the Gas SCADA Software Solution project are in the table provided below.

| **Gas SCADA Software Solution** | | | |
|---|---|---|---|
| **Case No. U-21806** | | | |
| **Cost Category** | **Total Company Capital** | **Gas Allocation Capital** | **U-21806 Reference** |
| **2023 Actuals** | | | |
| Software | $708,742 | $708,742 | A-20 (SHB-5), line 67, column m |
| Material | $946,533 | $946,533 | A-20 (SHB-5), line 67, column n |
| Labor | $53,782 | $53,782 | A-20 (SHB-5), line 67, column o |
| Contractor Costs | $219,054 | $219,054 | A-20 (SHB-5), line 67, column p |
| Non-Labor Overhead | $4,241 | $4,241 | A-20 (SHB-5), line 67, column q |
| Non-Labor Other | $17,212 | $17,212 | A-20 (SHB-5), line 67, column r |
| **Total 2023 Actuals** | **$1,949,564** | **$1,949,564** | A-20 (SHB-5), line 67, column l |
| **2024 Projected** | | | |
| Software | $555,511 | $555,511 | A-20 (SHB-5), line 171, column m |
| Material | $855,345 | $855,345 | A-20 (SHB-5), line 171, column n |

| | | | |
|---|---|---|---|
| Labor | $1,194,638 | $1,194,638 | A-20 (SHB-5), line 171, column o |
| Contractor Costs | $4,957,904 | $4,957,904 | A-20 (SHB-5), line 171, column p |
| Non-Labor Overhead | $23,030 | $23,030 | A-20 (SHB-5), line 171, column q |
| Non-Labor Other | $441,113 | $441,113 | A-20 (SHB-5), line 171, column r |
| **Total 2021 Projected** | **$8,027,542** | **$8,027,542** | A-20 (SHB-5), line 171, column l |
| **2025 Projected** | | | |
| Software | $2,083,987 | $2,083,987 | A-20 (SHB-5), line 261, column m |
| Material | $7,264 | $7,264 | A-20 (SHB-5), line 261, column n |
| Labor | $956,112 | $956,112 | A-20 (SHB-5), line 261, column o |
| Contractor Costs | $3,856,564 | $3,856,564 | A-20 (SHB-5), line 261, column p |
| Non-Labor Overhead | $324,519 | $324,519 | A-20 (SHB-5), line 261, column q |
| Non-Labor Other | $810,488 | $810,488 | A-20 (SHB-5), line 261, column r |
| **Total 2021 Projected** | **$8,038,934** | **$8,038,934** | A-20 (SHB-5), line 261, column l |
| **Total Actuals/Projected** | | | |
| Software | $3,348,240 | $3,348,240 | |
| Material | $1,809,142 | $1,809,142 | |
| Labor | $2,204,532 | $2,204,532 | |
| Contractor Costs | $9,033,522 | $9,033,522 | |
| Non-Labor Overhead | $351,790 | $351,790 | |
| Non-Labor Other | $1,268,814 | $1,268,814 | |
| **Total Actuals/Projected** | **$18,016,040** | **$18,016,040** | |

**Q. Why have the projected costs of the Gas SCADA Software Solution project changed from previous projections in Case No. U-21490?**

A. The initial projections provided were refined as the project progressed through investment planning and subsequent project stages in 2022 and 2023. The primary reasons for the $6.6 million increase in the Gas SCADA Software Solution project costs from the initial

projections presented in Case No. U-21490 are due to increases in contractor ($4.4 million), software ($1.75 million), and material ($0.46 million) costs of $6.6 million. The contractor costs increased because the vendor professional services were underestimated in the ROM estimate. Additionally, the Company determined that a third-party was required to support internal resources with testing, as the technology is new to the Company. The software licensing costs increased because the ROM estimate planned for a five-year period, but the project required six years of software subscriptions due to the length of the implementation. The material costs increased because the ROM estimate planned to purchase physical servers, but the Company decided to purchase virtual servers. The Company utilizes virtual servers because they provide cost efficiency, maximize the use of available resources, and offer more flexibility.

**Q. Please explain the test year projects included in the Customer area.**

A. Below are projects included within the Customer area. These digital investments support lower cost of customer service, increase customer engagement and enrollment in programs, and increase use of digital platforms. A synopsis of each project with its value is included in the direct testimony of Company witness Jessica R. Byrom:

| Project | Projected Test Year Capital | ROM Adjusted Test Year Capital | O&M |
|---|---|---|---|
| Customer Order Service Tracker | $547,715 | $438,172 | $150,951 |
| Genesys Cloud Migration | $0 | $0 | $5,392 |

Additionally, the Application Currency-Customer-O&M and Capital and Product Family Enhancements-Customer-O&M and Capital will be discussed later in my testimony.

**Q. Please explain the projects included in the Corporate area.**

A. Below are projects included within the Corporate area. These digital solutions can optimize and even transform these foundational services. A synopsis of each project with its value is included in the direct testimony of Company witness Matthew J. Foster:

| Project | Projected Test Year Capital | ROM Adjusted Test Year Capital | Test Year O&M |
|---|---|---|---|
| 2025 Union Contract Changes | $0 | $0 | $105,726 |
| Expense Reporting Improvements | $154,374 | $123,499 | $43,532 |
| Talent Management Enablement | $28,868 | $23,095 | $5,950 |
| Enterprise Risk Management | $0 | $0 | $26,423 |
| Self Service Vendor Portal | $35,311 | $28,248 | $39,811 |

Additionally, the Application Currency-Corporate-O&M and Capital and Product Family Enhancements-Corporate-O&M and Capital will be discussed later in my testimony.

**IT/Digital Foundations and Capabilities**

**ARP**

**Q. Please explain the value of projects included in ARP, and how the Company determines the hardware refresh frequency.**

A. The Company's ARP projects replace technology assets in line with industry and Company life-cycle expectations for the specific assets in each type of program. Replaced assets are recycled, donated, or sold if there is residual value. The Company's research shows that industry standards on refreshing hardware are generally three to five years, although the

Company refreshes monitors every eight years based on Company data related to historical failure rates. Refreshing hardware at the recommended cycle allows the Company to: (1) reduce security risks and help ensure devices are updated and patched to avoid vulnerabilities; (2) avoid costs due to increasing hardware failures; (3) avoid frustration for its customers and lost productivity for its employees due to downtime; (4) receive continued operating system support as older versions are retired by the manufacturer; and (5) ensure employees have the required hardware to support their work.

Below is a link to information on industry standards the Company has reviewed in determining its hardware refresh time periods:

- Michigan.gov, Information Technology Equipment Life Cycle: https://www.michigan.gov/documents/dtmb/Sec._829_IT_Lifecycle_Report_FY_2021_717757_7.pdf

**Q. Please describe Exhibit A-22 (SHB-7).**

A. Exhibit A-22 (SHB-7) shows the detailed projected and actual capital expenditures of each ARP. Specifically:

- Column (a) provides the unit description;
- Column (b) provides the average unit cost;
- Column (c) provides the total number of units for the specified year;
- Column (d) provides the total number of units for the specified year;
- Columns (e) through (f) provide total actual or projected capital expenditures for the specified year;
- Column (g) provides the total projected capital expenditures for the test year or the total actual gas allocation of capital expenditures for the specified year; and
- Column (h) provides gas allocation of capital expenditures for the specified year.

**Q. Please explain the ARP and infrastructure projects, as reflected in Exhibit A-22 (SHB-7).**

A. The following are the ARP and infrastructure projects:

- The **ARP-Collaboration** project requires $521,622 in capital and $82,999 in O&M in the test year.
  - **Description:** This project will replace the Company's obsolete or out-of-date audio, visual, telephony, and other communication collaborative tools and equipment.
  - **Problem Statement:** When Collaboration Assets that are used to support customer interactions and business operations are obsolete or out-of-date, they can be more difficult to keep current with Security updates. The Company also runs the risk of failure of these assets if it does not adhere to a regular refresh cycle.
  - **Objectives:** This project creates value by: (1) ensuring that the Company's audio, visual, telephony, and other communications systems are stable and reliable; and (2) migrate to new collaboration assets.
  - **Scope:** The project scope consists of: (1) annually replacing aging collaboration assets; and (2) installing new collaboration assets to account for evolving business requirements.
  - **Alternatives:** The following alternatives were considered: (1) refresh visual assets and a portion of the audio assets; (2) refresh a portion of the audio assets only; and (3) refresh visual assets only. These alternatives were not chosen due to the risk inherent with a partial replacement of assets, which includes: (1) a reduced supply of equivalent replacement Avaya parts that are no longer being produced; and (2) an erosion of the knowledge technicians possess on discontinued systems.
- The **ARP-Core Network** project requires $141,383 in capital and $10,542 in O&M in the test year.
  - **Description:** This project will refresh the Data Center network equipment.
  - **Problem Statement:** When network assets that are used to support customer interactions and ensure the stability of mission critical business operations are obsolete or out-of-date, they are more expensive to support and can be more difficult to keep current with security updates. The Company also runs the risk of failure of these assets if it does not adhere to a regular refresh cycle.

- **Objectives:** This project will create value for the Company and its customers by: (1) increasing network reliability; (2) adding new functionality; (3) improving network performance; and (4) standardizing network infrastructure across Data Centers.

- **Scope:** The project scope includes the replacement of all core network devices with next generation devices.

- **Alternatives:** The alternative considered was to continue running in the current state or delay the replacement of network devices and accept the risk of further business and customer impact when more equipment failures occur.

- The **ARP-Cyber Security** project requires $218,482 in capital and $9,302 in O&M in the test year.

  - **Description:** This project will replace cyber security infrastructure to support increasing system and application demands and to prevent system failures and service interruptions.

  - **Problem Statement:** When enterprise software or cyber security infrastructure used to support and enhance customer interactions is obsolete, these assets are more expensive to support and can be more difficult to keep current with security updates.

  - **Objectives:** This project will create value by maintaining the currency of the cyber security infrastructure for core enterprise software. These are used to ensure the stability of technology for business operations.

  - **Scope:** The scope of this project consists of: (1) annually replacing a subset of cyber security firewalls and servers in keeping with a three- to five-year hardware lifecycle; and (2) performing application upgrades.

  - **Alternatives:** As part of the review process, the alternatives considered were to: (1) upgrade or replace only those assets identified in the plan; (2) upgrade or replace a portion of the assets identified in the plan. Option 1 was not chosen based on continued refresh cycle for cyber security assets to avoid security risks, system vulnerabilities, and out-of-warranty repair costs. Option 2 was not chosen due to the security risk inherent with not replacing assets as per standard refresh cycles increased system vulnerabilities, and out-of-warranty repair costs.

- The **ARP-Infoblox Refresh** project requires $157,986 in capital and $13,270 in O&M in the test year.

  - **Description:** This project will replace the three legacy core components, Domain Name System ("DNS"), Dynamic Host Configuration Protocol

("DHCP"), and Internet Protocol Address Management ("IPAM") (collectively, "DDI") environment with a modern, vendor supported system. Infoblox is the DDI solution that the Company uses to enable seamless network communications across critical systems.

- **Problem Statement:** When Infoblox assets that are used to support customer interactions and ensure the stability of technology for business operations are obsolete or out-of-date, they are more expensive to support and can be more difficult to keep current with security updates. The Company also runs the risk of failure of these assets if it does not adhere to a regular refresh cycle.

- **Objectives:** The value of this program includes: (1) enabling the Company to efficiently manage and control their networks; and (2) providing DNS, DHCP, and IPAM.

- **Scope:** The scope of this project includes the replacement of DNS, DHCP and IPAM assets on a five- to seven-year refresh cycle.

- **Alternatives:** The alternative considered was to continue operating on existing Infoblox equipment past the vendor's end-of-support date. This alternative was not selected because it carries risks with not having vendor support, software bug fixes, security updates, and other software fixes. The alternative to replace the existing Infoblox equipment with the latest hardware and software provided by the vendor was selected to avoid these risks and continue a regular refresh cycle.

- The **ARP-Local Area Network ("LAN")** project requires $231,181 in capital and $18,280 in O&M in the test year.

  - **Description:** This project will upgrade the Company's entire LAN and a significant portion of the Wireless Local Area Network ("WLAN").

  - **Problem Statement:** At some Company locations, LAN equipment has been in service since 2011. If the LAN/WLAN hardware and software is not routinely refreshed, the Company will lose the manufacturer support needed for equipment bug fixes, security vulnerability patches, and enhancements. In addition, aging equipment cannot accommodate the increasing demand for wireless devices necessary to perform day-to-day operations that rely on wireless-enabled devices, such as rugged field devices, cell phones, barcode scanners, tablets, and other mobile devices. As equipment ages, it is at risk of higher failure rates, which increases the risk of unplanned outages. In the event of unplanned outages, business areas would not be able to access services on the corporate network including email, SAP, internet, and phones.

- **Objectives:** The project will create value for the Company and its customers by: (1) increasing network reliability; (2) adding new functionality; (3) improving network performance; (4) ensuring equipment is vendor supported, thereby ensuring support for bug fixes, security vulnerability patching, and enhanced features; (5) providing consistent wireless coverage across Company locations; (6) increasing user productivity through a higher performing wireless network, which increases the productivity and efficiency of office and field employees serving customers; and (7) improving support for wireless Internet Protocol ("IP") phones, Internet of Things ("IoT") and field devices.

- **Scope:** The project scope includes: (1) refreshing the LAN equipment and software across all Company sites; (2) identifying the required features for the new equipment; (3) implementing the new equipment according to industry best practices; (4) replacing wireless network with upgraded infrastructure and verifying wireless coverage is as expected; and (5) collecting wireless survey data for all Company locations in order to design improved wireless network coverage.

- **Alternatives:** The alternative considered was to continue operating on the existing platform past the vendors end-of-support date. The vendor support period ended in May 2021, and paying for extended support is not an option offered by the vendor. The risk inherent in not refreshing the platform is a lack of vendor support resulting in an absence of software bug fixes, security updates, and break fixes. The Company chose to replace the existing equipment with the latest hardware and software available, following a five year refresh cycle.

- The **ARP-OT Support Gas** project requires $2,468,066 in capital and $398,568 in O&M in the test year.

  - **Description:** This project will replace dated and obsolete servers on a rotating five-year refresh schedule.

  - **Problem Statement:** When OT Assets that are used to ensure the safety and reliability of technology that supports critical gas operations are obsolete or out-of-date, they can be more difficult to keep current with Security updates and run the risk of failure if the Company does not adhere to a regular refresh cycle.

  - **Objectives:** This project creates value by maintaining the currency of the Company's IT infrastructure and the core enterprise software that are utilized to support the operation of the Company's critical gas infrastructure.

- **Scope:** The program scope consists of: (1) replacement of computer hardware under the program; and (2) installing additional new computer capacity to account for expanding business requirements.

- **Alternatives:** The alternatives considered include: (1) continue to operate hardware beyond a five- to seven-year refresh cycle or (2) refresh hardware based on a five- to seven-year refresh cycle along with evaluating the health of the asset and evolving business needs. The alternative to operate hardware beyond a five- to seven-year refresh cycle was not selected due to the risk that these hardware component failures would cause system reliability and safety for customers, as vendors do not provide extended support after seven years. The Company chose the alternative to refresh this hardware based on a five- to seven-year refresh cycle along with evaluating the health of the asset and evolving business needs to reduce the risk of impacting critical infrastructure that supports systems such as Gas SCADA.

- The **ARP-Physical Security** project requires $747,487 in capital and $4,698 in O&M in the test year.

  - **Description:** The ARP-Physical Security, formerly known as Physical Security Asset Refresh, will enhance or replace physical security assets to provide improved visibility and incident resolution related to security concerns.

  - **Problem Statement:** The Company has several thousand physical security asset devices currently in use including security cameras, motion detectors, intrusion detection systems, and card access systems. Current limitations include the lack of integrated solutions for centralized management, situational awareness, real time monitoring, compliance with regulations and guidelines, and faster responses to emergencies and incidents. This could result in the increase of potential security vulnerabilities, associated penalties, and reputational damage.

  - **Objectives:** The value provided by completing the project is to: (1) maintain compliance with State and Federal Regulations; (2) reduce redundancies with less of a need for multiple cameras and reducing gaps in functionality; and (3) optimize overall system performance.

  - **Scope:** Included in the project is the enhancement or replacement of assets including: (1) advanced door systems at Company buildings; (2) security cameras for monitoring capabilities; and (3) gate and lock systems, which include security cameras, motion detectors, intrusion detection systems, and card access systems.

  - **Alternatives:** Alternatives considered include: (1) not refreshing physical security assets, and (2) defer a portion of the refresh of physical security

assets per an asset refresh cycle industry standard. Alternatives 1 and 2 were not selected due to the risk of security concerns, incident resolution, and the inability to meet FERC requirements. The alternative selected maintains compliance, reduces redundancies and gaps in functionality, and optimizes overall performance of physical security systems.

- The **ARP-Printer Asset Management ("PAM")** project requires $118,704 in capital and $1,860 in O&M in the test year.
  - **Description:** This project will replace and install select printers, plotters, and multi-function printing devices based on printer replacement assessments and a five-year refresh cycle. Printer service and usage history is evaluated and a determination is made if a printer can be repurposed instead of ordering a new one.
    - **Problem Statement:** When Printer Assets used to support customer interactions and business operations are obsolete or out-of-date, they are more expensive to support and keep current with firmware and security updates. The Company also runs the risk of failure of these assets if it does not adhere to a regular refresh cycle.
    - **Objectives:** This project creates value for the Company by: (1) improving the dependability of these printer devices for employees; (2) averting increased costs due to hardware repairs; and (3) ensuring compatibility with enterprise print applications.
    - **Scope:** The project scope consists of the annual replacement of printer assets according to a five-year refresh cycle.
    - **Alternatives:** The alternatives considered for the project included looking at refresh cycles from three to seven years as well as running the assets to failure. The selection of a five-year cycle was deemed to be the best solution since anything less than five years would increase the likelihood of unneeded expense for replacement of assets that were still in good operating condition. Anything greater than five years is assessed monthly to ensure it is not run-to-failure, including running the asset to failure, resulting in additional expenses for maintenance of the equipment and downtime, negatively affecting employee productivity. The Company assesses the printer fleet based on years of active service, service history, printer usage data, and the number of users within a facility. Based on these factors, the Company either decommissions, repurposes, leaves in place, or refreshes the printers.

**Q. Please explain the ARP-FDAM project.**

A. The ARP-FDAM project has the following synopsis:

- The **ARP-FDAM** project requires $2,192,211 in capital and $1,860 in O&M in the test year.
    - **Description:** This project will replace field devices according to a four-year refresh cycle that is based on industry standards, hardware failures, security patches, and software compatibility.
    - **Problem Statement:** When Field Device Assets used to support customer interactions and business operations are obsolete or out-of-date, they are more expensive to support and keep current with security updates as equipment becomes obsolete. The Company also runs the risk of failure of these assets if it does not adhere to a regular four-year refresh cycle.
    - **Objectives:** This project creates value for the Company by: (1) improving stability and availability of business-critical applications by proactively replacing field devices prior to increasing hardware failures; and (2) allowing field workers to complete their job tasks.
    - **Scope:** The project scope consists of replacing field device assets according to the four-year refresh cycle.
    - **Alternatives:** The alternatives considered were to: (1) extend the replacement cycle from four years to five years for field devices; and (2) use outdated equipment. The Company did not select these options because: (1) there would be an increased risk of hardware failure and equipment outages that could impact the capacity of business partners to complete job tasks; (2) it could cause applications to run poorly or stop functioning; (3) it would increase the assets that need refreshing in future years based on the number of devices that were not replaced during the four year refresh cycle; and (4) it could cause an inability to apply security patches. Based on industry data, waiting longer than the four-year cycle would increase hardware failures, security patch issues, and software compatibility concerns, resulting in additional downtime that could affect customer safety and storm restoration. The Company selected a four-year refresh cycle to alleviate these concerns.

**Q. How are the annual projected costs created for the ARP-FDAM project?**

A. The ARP-FDAM project has two categories, which are replacements and new purchases. Each of these categories include field devices. A further description of replacements and new purchases is as follows:

- **Replacements:**
  - Are determined by pulling the quantity of device types with a scheduled retirement year:
    - Field devices scheduled retirement year is four years from purchase;
  - The model of device determines the unit cost. The total of these devices with their current unit cost is established for a particular year's budget;
  - Accessories for field devices are projected based on the number of planned replacements and include desk docks, vehicle docks, and ac adapters; and
  - Carryover devices are added from the previous year to address aging devices first.
- **New Purchases:**
  - Are determined based on People and Culture hiring estimations and any known field device needs of a particular work group (e.g. some field groups require large screen sizes);
  - The model of device and monitor determines the unit cost; and
  - Accessories for field devices are projected based on the number of planned new purchases.

The four-year cycle for field devices, along with the projected new purchases, are listed in the associated Exhibit A-22 (SHB-7).

**Q. Please describe variances from year to year for the ARP-FDAM project.**

A. Variances for the ARP-FDAM project are a result of changes to scheduled replacements per four-year field device and incremental unit cost increases. Starting in 2024, there has been a one-time change for new field device purchases. These devices are now a part of the ARP-FDAM project, rather than the ARP-WAM project. Moreover, there is a change in the replacement of some field devices, which were initially planned under the ARP-WAM project. These devices were included in ARP-FDAM starting in the year 2024. Exhibit A-22 (SHB-7), page 4, details the devices, number of units, and unit costs for each

type of device. Below are summary charts with the variance reasons for each year separated between replacement and new purchase categories.

**Replacements**

| Year | Field Device | Reason for variance |
|---|---|---|
| 2023 Actual | 715 | Field device replacements based on refresh schedule. |
| 2024 Plan | 678 | • Field device replacements based on refresh schedules.<br>• 84 field device replacements moved from ARP-WAM to ARP-FDAM. |
| 2025 Plan | 538 | Field device replacements based on refresh schedule. |
| 2026 Plan | 1,325 | Field device replacements based on refresh schedule. |

**New Purchases**

| Year | Field Device | Reason for variance |
|---|---|---|
| 2023 Actual | 0 | 140 field devices new purchases based on actual new employee/contractor volume and were accounted for as part of ARP-WAM, not ARP-FDAM. |
| 2024 Plan | 107 | Projection for 2024 based on People and Culture estimated hiring, which were previously projected as a part of ARP-WAM. |
| 2025 Plan | 200 | Projection for 2025 based on People and Culture estimated hiring. |
| 2026 Plan | 200 | Projection for 2026 based on People and Culture estimated hiring. |

**Q. Do the Company's 2025 projected gas allocation capital expenditures for material costs for the ARP-FDAM project differ from the $1,476,310 projected in Case No. U-21490?**

A. Yes. The 2025 projected gas allocation capital expenditures for material costs for the ARP-FDAM project of $1,061,230 (Confidential Exhibit A-20 (SHB-5), line 273, column (n)) is $415,080 less than the $1,476,310 projected in Case No. U-21490 (Exhibit A-20 (SHB-5), column (m), line 329.

The following describes the reason for the difference:

1. Field device replacements decrease of $0.4 million that were initially projected as a part of ARP-WAM in Case No. U-21490; and

2. Accessories increased by $0.01 million associated with projected new purchases of field devices.

**Q. Please explain the ARP-Radio project.**

A. The ARP-Radio project has the following synopsis:

- The **ARP-Radio** project requires $1,200,164 in capital and $75,865 in O&M in the test year.
    - **Description:** This project will refresh hardware to include 800Mhz Radios and infrastructure, cellular modems, plant radios and systems, cellular amplification devices and vehicle consoles in service trucks. This equipment supports mission critical voice and data communications for plant and field service personnel and dispatch personnel. 800MHz radios are upgraded on a 10-year lifecycle basis. Plant radio systems are upgraded on a scheduled seven-year lifecycle basis. Cellular modems are refreshed on a five-year life cycle basis. Amplification systems are refreshed on a 10-year life cycle.
    - **Problem Statement:** Vehicle consoles are typically retired with the vehicle but are salvaged for reuse in new vehicles when possible. 800MHz, mobile, and portable radios, Plant radios systems, and Cellular modems support core business functions, life safety communications, and rapid response for restoration of customer service and critical infrastructure. Company radio systems must be refreshed on a scheduled basis or risk exceeding life expectancy and failing. The refresh of these subscriber units in a proactive manner is critical to providing service to customers. If these units are not refreshed, the increased risk of unit failure would result in interruptions to timely and concise communications to field personnel to resolve gas leaks, and downed electric lines, or service turn-on requests, which risks life safety.
    - **Objectives:** This project creates value for customers and the Company by: (1) upholding public safety; (2) ensuring timely responses and repairs to emergent gas leaks, wire downs, and electric outages; (3) ensuring real-time communications between Company dispatch locations and crews in the field; (4) ensuring the safety of personnel working in higher risk workspaces by replacing equipment with units that contain intrinsically safe batteries; (5) supporting continuous improvement and training by replacing equipment that is capable of capturing audio recordings; and (6) remaining

in compliance with MPSC regulatory requirements by maintaining critical radio infrastructure.

- **Scope:** The project scope consists of: (1) scheduled replacement of radios, modems, and consoles; (2) installing additional radios modems and console assets to satisfy growth requirements; and (3) scheduled replacement of out-of-date cellular and radio boosters.

- **Alternatives:** The alternatives considered included: (1) Replace the existing units with new units from other radio and modem manufacturers; and (2) purchase new radio subscriber units from existing manufacturers. Option 2 was not selected because the Company now uses a standards-based radio system allowing for multiple radio manufacturer options. Option 1 was selected to allow for a competitive bidding process that will provide the most cost-effective radio that will meet the needs of users.

**Q. Do the Company's 2023 actual gas allocation capital expenditures for material costs for the ARP-Radio project differ from the $459,501 projected in Case No. U-21490?**

A. Yes. The 2023 actual gas allocation capital expenditures for material costs for the ARP-Radio project of $304,384 (Confidential Exhibit A-20 (SHB-5), column (n), line 75) are $155,117 less than the $459,501 projected in Case No. U-21490 (Exhibit A-20 (SHB-5), column (m), line 178.

The difference is explained by the Company being able to avoid purchasing 100 Havis boxes due to its decision to reduce the number of Company vehicles. The Havis boxes from the vehicles that were sold have been repurposed. Additionally, the Company conducted a request for proposal for the radios planned for 2024, which has resulted in a lower radio unit cost. However, the purchase of bi-directional amplifiers deferred from 2022 that are end of life and require refresh to support newer cellular technologies (such as 5G) offset some of these savings.

**Q. Please explain the ARP-Server and Storage project.**

A. The ARP-Server and Storage project has the following synopsis:

- The **ARP-Server and Storage** project requires $694,196 in capital and $158,399 in O&M in the test year.

  - **Description:** This project will replace or augment server and storage infrastructure for the Company.

  - **Problem Statement:** When Server and Storage Hardware Assets used to support customer interactions and business operations are obsolete or out-of-date, they are more expensive to support and can be more challenging to keep current with Security updates. The Company also runs the risk of failure of these assets impacting customer interactions and business operations if it does not adhere to a regular five- to seven-year refresh cycle.

  - **Objectives:** This project creates value for the Company through: (1) improved stability and availability of business-critical applications by proactively replacing server and storage hardware assets prior to the likelihood of increasing hardware failures; and (2) ensuring that adequate resources are available to support application demands after five to seven years of actual use.

  - **Scope:** The scope of this program encompasses: (1) replacement of server and storage hardware assets; and (2) installation of additional new computers and storage capacity to account for evolving business requirements.

  - **Alternatives:** The alternatives considered were to purchase extended maintenance, move some of these assets to the cloud with the Digital-Hybrid Cloud and Data Center Migration project, or to replace the assets on the current cycle. The option to purchase extended maintenance was not selected because full support would not be offered after seven years, and maintenance costs would increase. The preferred option is to move some of these assets to the cloud in the Digital-Hybrid Cloud and Data Center Migration project while refreshing the remainder using the five- to seven-year cycle as it is the most cost-effective option. If the Digital-Hybrid Cloud and Data Center Migration project is not approved as part of this rate case, the Company plans to continue to refresh these critical technologies at the current level based on a five- to seven-year refresh cycle to mitigate the risk of failure.

**Q. Do the Company's 2024 projected gas allocation capital expenditures for material costs for the ARP-Server and Storage project differ from the $579,318 projected in Case No. U-21490?**

A. Yes. The 2024 projected gas allocation capital expenditures for material costs for the ARP-Server and Storage project of $200,604 (Confidential Exhibit A-20 (SHB-5), column (n), line 185) are $378,714 less than the $579,318 projected in Case No. U-21490 (Exhibit A-20 (SHB-5), column (m), line 260.

The difference is explained by the Company's decision to migrate to SAP HANA database in 2023, which is discussed later in my testimony. As a result, the Company did not proceed with refreshing the SAP infrastructure.

**Q. Please explain the ARP-WAM project.**

A. The ARP-WAM project has the following synopsis:

- The **ARP- WAM** project requires $2,060,439 in capital and $24,426 in O&M in the test year.
  - **Description:** This project will replace and install new desktops, laptops, and tablets on a four-year refresh cycle based on industry standards, hardware failures, security patches, and software compatibility. Monitors will be replaced every eight years based on Company data related to historical failure rates.
  - **Problem Statement:** When Workstation Assets that are used to support customer interactions and business operations are obsolete or out-of-date, they are more expensive to support and keep current with security updates as equipment becomes obsolete. The Company also runs the risk of failure of these assets if it does not adhere to a regular refresh cycle.
  - **Objectives:** This project creates value for the Company by: (1) improving stability and availability of business-critical applications by proactively replacing workstations prior to increasing hardware failures; and (2) allowing business partners to complete their job tasks.
  - **Scope:** The project scope consists of: (1) replacing workstation assets; and (2) installing new units for new resources.

- **Alternatives:** The alternatives considered were to: (1) extend the replacement cycle from four years to five years for all desktops and laptops; (2) extend the replacement cycle only on desktops from four years to five years; and (3) use outdated equipment. The Company did not select these options because: (1) there would be an increased risk of hardware failure and equipment outages that could impact the capacity of business partners to complete job tasks; (2) it could cause applications to run poorly or stop functioning; (3) it would increase the ARP in future years based on the number of devices that were not replaced during the four year refresh cycle; and (4) it could cause an inability to apply security patches. Based on industry data, waiting longer than the four-year cycle would increase hardware failures, security patch issues, and software compatibility concerns, resulting in additional downtime that could affect customer safety and storm restoration. The Company selected a four-year refresh cycle for desktops, laptops, and tablets; and an eight-year cycle for monitors to alleviate these concerns.

**Q. Would increasing the replacement cycle for the ARP-WAM refresh cycle from four years to five to seven years have a negative impact on the Company and its customers?**

A. Yes. Increasing the replacement cycle for Personal Computer ("PC") Devices from four years to five to seven years would have a negative impact on the Company and its customers. This is demonstrated through industry data, internal incident data, PC warranty duration, and lost productivity.

- These references reinforce replacing PCs at four years or less:
  - Michigan.gov, Information Technology Equipment Life Cycle. https://www.michigan.gov/documents/dtmb/Sec._829_IT_Lifecycle_Report_FY_2021_717757_7.pdf
  - https://i.crn.com/sites/default/files/ckfinderimages/userfiles/images/crn/custom/INTELBCCSITENEW/WhitePaper_EnterpriseRefresh.pdf
- The vendor's three-year warranty duration for Company PCs combined with the incident history reinforce four years is the optimum time for replacement.

The labor cost of addressing incidents and lost productivity, the warranty period, and external references confirm PC and field device replacement on a four-year cycle.

Similarly, Company historical failure rates for monitors indicate an eight-year cycle as ideal, which is what the Company employs for monitors.

**Q. How are the annual projected costs created for the ARP-WAM project?**

A. The ARP-WAM project has two categories, which are replacements and new purchases. Each of these categories include PC devices and monitors. A further description of replacements and new purchases is as follows:

- **Replacements:**
  - Are determined by pulling the quantity of device types with a scheduled retirement year:
    - PC devices scheduled retirement year is four years from purchase, and
    - Monitors scheduled retirement year is eight years from purchase.
  - The model of device determines the unit cost. The total of these devices with their current unit cost is established for a particular year's budget;
  - Accessories for PC devices are projected based on the number of planned replacements and include keyboards, surge protectors, docks, backpacks, and cables; and
  - Carryover devices are added from the previous year to address aging devices first.
- **New Purchases:**
  - Are determined based on People and Culture hiring estimations and any known PC device needs of a particular work group (e.g. some engineering groups require high performance devices);
  - Associated new monitors to go along with the PC devices are identified;
  - The model of device and monitor determines the unit cost; and
  - Accessories for PC devices are projected based on the number of planned new purchases.

The four-year cycle for PC devices and the eight-year cycle for monitors, along with the projected new purchases, are listed in the associated Exhibit A-22 (SHB-7).

**Q. Please describe variances from year to year for the ARP-WAM project.**

A. Variances for the ARP-WAM project are a result of changes to scheduled replacements per four-year PC device and eight-year monitor refresh cycles, previous year deferrals for equipment replacements primarily due to disallowances, and incremental unit cost increases. Starting in 2025, there has been a one-time change for new field device purchases. These devices will now be a part of the ARP-FDAM project, rather than the ARP-WAM project. Moreover, there is a change in the replacement of some field devices, which were initially planned under the ARP-WAM project. Exhibit A-22 (SHB-7), page 12, details the devices, number of units, and unit costs for each type of device. Below are summary charts with the variance reasons for each year separated between replacement and new purchase categories.

**Replacements**

| Year | PC Device | Monitor | Reason for variance |
|---|---|---|---|
| 2023 Actual | 2,153 | 0 | • 296 PC devices that could not be replaced due to disallowances were deferred to 2023.<br>• 118 PC devices that could not be replaced due to resource availability were deferred from 2023 to 2024. |
| 2024 Plan | 1,869 | 105 | • 118 PC devices that could not be replaced due to resource availability were deferred from 2023 to 2024.<br>• Monitor replacements associated with 118 PC devices that were deferred to 2024.<br>• 1,015 PC devices that are not planned to be replaced due to reduction in resources. |
| 2025 Plan | 3,376 | 0 | • No monitor replacements planned since monitors' eight-year replacement cycle was completed 2018-2021. The next monitor replacement is targeted to resume in 2027. |
| 2026 Plan | 2,215 | 0 | • No monitor replacements planned since monitors' eight-year replacement cycle was completed 2018-2021. The next monitor replacement is targeted to resume in 2027. |

**New Purchases**

| Year | PC Device | Monitor | Reason for variance |
|---|---|---|---|
| 2023 Actual | 284 | 171 | Based on actual new employee/contractor volume. |
| 2024 Plan | 197 | 145 | • 248 fewer PC devices for 2024 based on People and Culture estimated hiring.<br>• 220 fewer monitors for 2024 based on People and Culture estimated hiring. |
| 2025 Plan | 393 | 400 | Projection for 2025 based on People and Culture estimated hiring. |
| 2026 Plan | 393 | 400 | Projection for 2026 based on People and Culture estimated hiring. |

**Q. Do the Company's 2023 actual gas allocation capital expenditures for material costs for the ARP-WAM project differ from the $2,268,452 projected in Case No. U-21490?**

A. Yes. The 2023 actual gas allocation capital expenditures for material costs for the ARP-WAM project of $1,873,353 (Confidential Exhibit A-20 (SHB-5), column (m), line 83) are $395,099 less than the $2,268,452 projected in Case No. U-21490 (Exhibit A-20 (SHB-5), column (m), line 186).

The following describes the difference:

1. Desktop replacements decreased by $0.03 million due to 118 replacements being deferred to 2024 due to time needed to analyze whether the devices should be replaced or collected based on usage and offset by reduction in resources;

2. Laptop and rugged device replacements decreased by $0.41 million due to reduction in resources;

3. Accessories decreased by $0.09 million; and

4. New PC purchases increased by $0.21 million based on actual hiring.

**Q. Do the Company's 2024 projected gas allocation capital expenditures for material costs for the ARP-WAM project differ from the $2,071,350 projected in Case No. U-21490?**

A. Yes. The 2024 projected gas allocation capital expenditures for material costs for the ARP-WAM project of $1,712,808 (Confidential Exhibit A-20 (SHB-5), column (n), line 186) are $358,542 less than the $2,071,350 projected in Case No. U-21490 (Exhibit A-20 (SHB-5), column (m), line 261).

The following describes the difference:

1. Desktops and monitor replacements were net neutral due to 118 replacements being deferred, as discussed above, then offset by replacements not needed due to reduction in resources;
2. Laptop and tablets replacements decreased by $0.25 million based on reductions in resources;
3. RT Mount device increased by $.13 million;
4. Accessories decreased by $0.1 million; and
5. New PC and monitor purchases decreased by $0.14 million based on projected hiring.

**Upgrades, Replacements, and Application Currency Projects**

**Q. What are Upgrades, Replacements, and Application Currency projects?**

A. Upgrades, Replacements, and Application Currency projects are projects that address the need to upgrade or replace software applications and underlying platforms to a more current version to maintain prudent levels of security, reliability, and interoperability with associated systems. The Company performs security risk and various types of technical analysis to determine which applications need upgrading or replacing and when. Upgrade and replacement projects are created for larger and more complex application and platform upgrades or replacements that require increased oversight and project management.

Smaller upgrades are aggregated by IT product line and spend type in the Application Currency projects.

**Q. Please explain the Upgrades and Replacements projects.**

A. The following is an explanation of the Upgrades and Replacements projects:

- The **Asset Accounting Tax Upgrade** project requires $126,165 in O&M in the test year.
  - **Description:** The project will upgrade the Company's current accounting asset management tax software to the SaaS version as required by the vendor or a replacement solution and implement additional new features, ensuring continued support of a critical financial application, and providing new functionality.
  - **Problem Statement:** In 2025, standard vendor support ends for the current on-premise PowerTax software. Losing vendor support creates security and stability risk that can result in performance issues. When the application is out of the normal support with the vendor, the Company no longer receives security patches, support for defect resolution or bug fixes, and cannot enhance the application. To ensure compliance with regulated and financial accounting in the fixed asset sub-ledger, it is necessary to perform an upgrade and maintain vendor support. In addition, the upgrade provides additional functionality to increase the frequency of financial reporting and improve visibility.
  - **Objectives:** This project creates value for the Company by ensuring compliance with regulated and financial accounting within the fixed asset sub-ledger. In addition, the project adds value by: (1) moving to a SaaS solution in order to stay supported; and (2) reducing security, stability, and performance risk by ensuring consistent, seamless vendor support.
  - **Scope:** The project scope includes: (1) evaluating current vendor/product solution with market leaders; and (2) upgrading the vendor software from the current version to the newer SaaS version or replacing it.
  - **Alternatives:** Alternatives considered include: (1) Evaluate other software options. This option will introduce new ongoing support costs and integrations and may not provide regulatory reporting and other needed improvements. (2) Do nothing and remain on unsupported, on-prem tax solution. This option introduces technical and financial risk which would be costly. (3) Upgrade to the newest SaaS version of current on-prem solution. This is the preferred option as it will reduce hardware and server support costs, provide more frequent software upgrades, avoid database and

server upgrades, provide weekly allocation functionality, and provide new features in job scheduling, regulatory reporting for Cost of Service, reporting, and centralized error processing.

- The **Asset Accounting Upgrade 2025-2026** project requires $58,931 in O&M in the test year.
  - **Description:** The project will upgrade the Company's current accounting asset management software to the latest version as required by the vendor, ensuring continued support of a critical financial application.
  - **Problem Statement:** In 2027, standard vendor support ends for the current on-premise software. Losing vendor support creates security and stability risk that can result in performance issues. When the application is out of the normal support with the vendor, the Company no longer receives security patches, support for defect resolution or bug fixes, and cannot enhance the application. To ensure compliance with regulated and financial accounting in the fixed asset sub-ledger, it is necessary to perform an upgrade and maintain vendor support. In addition, the upgrade provides additional functionality to increase the frequency of financial reporting and improve visibility.
  - **Objectives:** This project creates value for the Company by ensuring compliance with regulated and financial accounting within the fixed asset sub-ledger. In addition, the project adds value by: (1) performing the allocation process on a more frequent basis providing better financial visibility; (2) automating manual tasks; and (3) reducing security, stability, and performance risk by ensuring consistent, seamless vendor support.
  - **Scope:** The project scope includes: (1) evaluating current vendor/product solution with market leaders; (2) upgrading the vendor software from the current version to the newer version.
  - **Alternatives:** Alternatives considered include: (1) Evaluate SAP options for leasing, asset, and tax management capabilities. While this option would eliminate the need for an interface between SAP and PowerPlan, it would be more complex, cost more, and not provide all the required features. (2) Evaluate other software options. This option will introduce new ongoing support costs and integrations and may not provide regulatory reporting and other needed improvements. (3) Upgrade to the newest version of current solution. This is the preferred option as it will reduce hardware and server support costs, provide more frequent software upgrades, avoid database and server upgrades, provide weekly allocation functionality, and provide new features in job scheduling, regulatory reporting for Cost of Service, reporting, and centralized error processing.

- The **Energy Assistance Enhancements and Maintenance Annual Updates** project requires $123,769 in O&M in the test year.

    - **Description:** The Energy Assistance Enhancements and Maintenance Annual Updates project, formerly known as Consumers Affordable Resource for Energy ("CARE") project, will implement software changes to offer energy assistance to low-income customers and streamline the process for the assistance agencies who use the assistance portal. This is accomplished through improved user interfaces and updates to SAP to process various requests. Upcoming modifications will be identified following an ongoing and annual review of requests, that includes criteria from the Department of Health and Human Services ("DHHS") and the MPSC to prioritize the list of changes.

    - **Problem Statement:** Each grant year, DHHS and the MPSC stipulate the criteria required for customers to enroll in the CARE program, how the Company and agencies will manage the enrollment process and track active CARE customers, and how they will administer the Michigan Energy Assistance Program ("MEAP") benefits through bill credits and arrears forgiveness. The criteria changes significantly each year; therefore, the Energy Assistance Enhancement and Maintenance Annual Updates application requires modifications to meet the new requirements. If the regulatory requirements are not fulfilled, the Company is at risk of losing state Low Income Home Energy Assistance Program ("LIHEAP") funds to assist low-income customers with paying their energy bills, thereby increasing the customer risk of shutoff for non-payment. In addition, the Company's energy assistance programs function within all software platforms in the Company which consistently need enhancements and updates.

    - **Objectives:** The project will provide the following value: (1) complete modifications to internal SAP application and Agency Portal to receive LIHEAP funding, which can be used to provide customers bill credits and arrears forgiveness; (2) improve the data within the assistance agencies portal, thereby making it easier to assist customers in need of LIHEAP funding; and (3) complete modifications to customer facing platforms.

    - **Scope:** The project scope includes: (1) updating the enrollment and status process; (2) allowing for flat monthly bills; (3) improving reporting; (4) updating the arrears forgiveness plan; (5) satisfying additional regulatory requirements for the annual grant rule changes required by DHHS and the MPSC; (6) updating CARE dunning process; and (7) updating CE PASS functionality to enhance Agency Self-Service.

- **Alternatives:** Alternatives considered included: (1) continue with current process, which would lead to loss of grant funding, thus decreasing or eliminating energy assistance dollars for customers; (2) transfer administration

of Energy Assistance Programs to a third party organization, which would remove ownership and visibility into the health of the program while increasing administrative costs; and (3) make annual updates to the application, which will allow agencies to easily enroll customers on assistance programs and allow placement of holds to stop or prolong credit activity until assistance decisions are granted. Option 3 was selected since it provides long-term proactive energy assistance to customers and prevents loss of grant funds. Changes are required to internal systems (SAP, Agency Portal, etc.), therefore a cloud or third-party alternative is not viable. Additionally, retiring the existing Agency Portal for a new application would increase costs beyond that of the routine upgrades.

- The **Enterprise Service Bus Application 2024-2025 Upgrade** project requires $48,200 in O&M in the test year.
    - **Description:** This project will upgrade and migrate the Business Works developer application to the next version.
    - **Problem Statement:** Newer ESB software versions offer improved integration with Rest/API services and applications. It is critical that this vital data tool or pathway be more scalable, secure, and capable of integrating to a service-based environment. In addition, the messaging and event modules within the ESB are currently outside of their standard support windows. While it is possible to continue to get extended support by paying an estimated premium of approximately $80,000 annually, this is just temporary coverage and serves only to delay the need for an upgrade.
    - **Objectives:** The value this project provides the Company includes: (1) cost avoidance to avoid extensive payments for extend support purposes; (2) avoid technical obsolescence; (3) operational resiliency; and (4) improved administrative and operational efficiencies.
    - **Scope:** The project scope includes implementing current version of all applications that are part of the ESB application, database version, and required database drivers.
    - **Alternatives:** Alternatives considered included: (1) Accept the annual $80,000 extended maintenance cost. Given the critical nature of this application, it is not recommended to lose mainstream support for any of the applications involved. Any sustained ESB product deficiency would impact many areas of the Company, such as billing, revenue collection, and remote meter management. The current implementation of the ESB platform was built with five years of growth in mind. This alternative was not chosen due to risk to Company operations, and the additional expense. (2) Replace the on-premise upgrade plan to implement a cloud-based solution. A cloud migration would also take longer to complete, which would put the Company at risk of falling outside of the current vendor support window for the product's current version. (3) Upgrade the existing

application. This option was selected because it best meets the Company needs for the near future by restoring vendor support for fixes and patches, and enables product scalability to the measure required of business capabilities.

- The **HR Support Pack and Business Software Inc ("BSI") Upgrade 2025 and 2026** projects require the following O&M in the test year.

| Project Year | Test Year O&M |
|---|---|
| 2025 | $59,576 |
| 2026 | $237,741 |

  - **Description:** The HR Support Pack and BSI upgrade will update the SAP system with HR Support Packs that are released annually by SAP to comply with HR and tax changes.

  - **Problem Statement:** SAP releases annual HR support packs to ensure compliance. Without them, the Company would be unable to comply with HR and tax changes, resulting in the inability to calculate and distribute payroll.

  - **Objectives:** This project creates value for the Company by: (1) ensuring that its systems are in compliance with new financial rules and regulations; and (2) ensuring that it can calculate and distribute payroll.

  - **Scope:** The scope of this project is to add SAP HR corrections to ensure proper reporting of financial information by the Company.

  - **Alternatives:** As this is an upgrade of an existing system, the alternative considered was to delay the upgrade. This alternative was not chosen due to the risk of not complying with financial rules and regulations.

- The **ISIS Papyrus 2026 Upgrade** project requires $188,501 in capital ($150,801 ROM Adjusted Capital) and $85,576 in O&M in the test year.

  - **Description:** This project will upgrade the Papyrus Objects suite of applications to the most recent version available per vendor recommendation. The ISIS Papyrus application is critical to creating electronic and paper correspondence for customers, including bills and dunnings.

  - **Problem Statement:** The application will be at least 1 major upgrade revision behind by 2026. In addition, the infrastructure will need replacement in 2026 (both hardware and OS). It is imperative that customers retain unfettered access to their paper bills, dunning notices and other communications produced by ISIS. ISIS also makes customer bills available for online viewing through the website and mobile apps. Without

the upgrade, our vendors make no guarantee that any substantial patches or hot fixes impacting application reliability, capacity, and security will be forthcoming. The upgrade will address these problems and challenges, as well as ensure all other platform components comply with our company operational and security standards.

- **Objectives:** The value of this project includes: (1) providing a more stable operational model by upgrading to the most recent version available; (2) maintaining the necessary vendor support; and (3) resolving tuning and stability issues with the vendors.

- **Scope:** The scope of the project is to upgrade the various licensed products that comprise the Papyrus Objects suite of applications.

- **Alternatives:** As this is an upgrade of an existing system, the alternative considered was to delay the upgrade and continue operating with the current version. This alternative was not chosen due to the risk of application stability and the inability to maintain cyber security patching.

- The **Itron Enterprise Edition ("IEE") 2025 Upgrade** project requires $48,856 in O&M in the test year.

  - **Description:** This project will upgrade IEE, which collects the reads from meters to ensure non-estimated bill accuracy.

  - **Problem Statement:** IEE is the Company's keystone application of the Advanced Metering Infrastructure, that provides billing data that includes time of use data. If this application does not stay current, the Company increases the risk business operations could be interrupted or compromised. IEE is a key component in keeping the Company current, with billing capacity, stability, and accuracy obligations.

  - **Objectives:** This project creates value for the Company by: (1) ensuring the features and functionality needed to meet and exceed customer satisfaction and billing accuracy are available to business partners and IT; and (2) meeting Information Security's requirement to keep applications patched and protected from cyber attack.

  - **Scope:** The scope of this project includes: (1) upgrading the IEE applications to the next appropriate versions; (2) migrating the database to the next version required by the application; and (3) replacing hardware required by the next version to maintain operating system currency.

  - **Alternatives:** Alternatives considered included: (1) Defer the upgrade. This alternative was not selected because it would decouple IEE (the Company's Meter Data Management) from the Itron security infrastructure introducing application stability, security, and dependency risks to the utility, possibly negatively impacting critical customer electric and gas

billing operations. It would also likely affect other business critical Itron applications use, creating more expense support and no ability to leverage updated tool capability. (2) Replace the platform. Replacing IEE/MDM would require the application business owners to undertake a new initiative mirroring the expense and effort that went into the multi-million dollar project responsible for setting up and leveraging this utility. (3) Perform the upgrade. This option is superior because it maintains vendor support for hot fixes and patches, and aligns with all upgrade projects related to other Itron products.

- The **Next Generation electronic Shift Operations Management System ("eSOMS") Replacement** project requires $157,182 in capital ($125,746 ROM Adjusted Capital) and $8,243 in O&M in the test year.

  - **Description:** The project replaces the eSOMS with updated clearance lock out tag out ("LOTO") management software for Electric Generation facilities, and narrative logs and mobile rounds functionality for Electric Generation and Gas Compression facilities.

  - **Problem Statement:** The vendor is replacing the current system used at the Company and other utilities with a new software package called Lumada. The software migration is necessary for the Company to retain vendor support, so that the databases continue to receive security patches, bug fixes, and functionality support from the vendor, and avoid security, stability, and reliability risk.

  - **Objectives:** The project will add value by: (1) maintaining functionality of a critical life safety application; (2) reducing the human struggle that comes from manual workarounds and an older application; (3) empowering employees with proper electronic tools to meet customer expectations; (4) enabling process improvements to deliver outages more effectively; (5) reducing plant downtime; (6) increasing reliability; and (7) increasing standardization across the Company.

  - **Scope:** The scope of this project includes: (1) configuring software for clearance management, logbook, rounds, automated emails, and reporting; (2) migrating and archiving data; (3) enabling additional offline capabilities, (4) integrating with SAP for equipment and current status of work orders; (5) adding new integration to SAP for notifications from rounds and clearance functions; (6) testing the software, data migrations and integrations; and (7) updating configuration management database, runbook, system recovery plan, LOTO work procedure, qualification training and other standard documentation.

- **Alternatives:** Alternatives considered include: (1) continuing to use the eSOMS application, though without vendor support. This alternative was not selected because losing vendor support for this critical application increases

risks for application security, reliability, and supportability that can result in an employee safety incident in the complex tagging process, an extended plant production outage, a prolonged plant reliability issue, or regulatory or compliance violations. (2) Instituting the manual business continuity process until the application replacement is possible. This alternative was not selected because it would also increase the previously mentioned operational risks. (3) Replacing the eSOMS application by customizing SAP. This alternative was not selected as it would be more expensive and introduce additional risk to employees due to poor application fit. (4) Migrating the existing eSOMS data to an out of the box application such as the Lumada application. The option to migrate the existing eSOMS application to an out of the box solution was chosen to minimize cost and risk to the Company and its employees. Cloud hosting of the application infrastructure at the vendor's location was also evaluated, though due to the greater cost of this vendor hosting, the application infrastructure will be hosted on premise at the Company.

- The **Rate Change Maintenance** project requires $118,372 in O&M in the test year.

  - **Description:** The Rates Change Maintenance project will modify SAP billing in accordance with pricing and rate change requirements.

  - **Problem Statement:** For the Company to continue to meet and comply with the MPSC rate change requirements, there is a need to make periodic updates/modifications to the existing prices and rate structures. These updates help ensure accuracy of billing and provide optimal rates for customers.

  - **Objectives:** The project will add value for both the Company and its customers through: (1) improved customer satisfaction by providing accurate billing; (2) optimized rate configuration enabling rate changes to be made more efficiently; and (3) timely updates to Company applications that incorporate mandatory changes to the rate structure that includes new surcharges, price changes, and energy efficiency programs.

  - **Scope:** The scope of this project encompasses (1) implementation of annual or monthly (or both) electric and gas customer price changes, and rate structure changes as approved by the MSPC; and (2) optimizing the rate configuration in the Company's back-end system for more efficient rate changes.

  - **Alternatives:** An alternative considered for this effort was a fully dedicated offshore development model. The option ensured resources were readily available with a more cost-effective labor expense. This alternative was not chosen due to the risk of billing inaccuracies and customer complaints. These risks were deemed too high because of the complexities of the rate structure, new development, and the timing it would take for testing of this

model. Cloud is not an applicable option in this case as we are not replacing any software. The option to use onshore resources to plan, coordinate, and execute the rate changes was selected as it supports the Company's operation model for rate changes.

- The **Replacement for Gas Automated Meter Reading ("AMR") Technology** project requires $856,334 in capital ($685,067 ROM Adjusted Capital) and $93,405 in O&M in the test year.

  - **Description:** This project will replace Itron Field Collection Systems ("FCS") and Itron Mobile with the newest Itron SaaS Temetra along with replacing Itron Mobile with Temetra Mobile for Gas AMR meters. This will allow the Company to leverage new cloud capabilities and align with the Company's Cloud strategy.

  - **Problem Statement:** The Company is using FCS and FCS mobile to gather gas meter reads. The vendor is replacing these systems with new Cloud software called Temetra and Temetra Mobile due to FCS and Itron Mobile being end of life December 2026. The software migration is necessary to maintain vendor support (latest security patches, bug fixes, latest functionality) while avoiding security, stability, and reliability risks for the Company. Moving to Itron Temetra will ensure no gas meter reading disruption and continued integration with existing gas communication modules and Itron Security Manager.

  - **Objectives:** The project adds value by: (1) continuing to collect accurate and timely gas meter reads; (2) removing the risk of being on unsupported versions; (3) utilizing the latest functionality such as retrieving historic read data, photos, and reports directly from Temetra; (4) seamlessly getting up to date security patches; (5) and reducing ongoing networking equipment replacement and upgrade costs.

  - **Scope:** Included in the implementation is: (1) configuring and deploying Temetra and Temetra Mobile; (2) migrating data; (3) integrating to IEE, Itron Security Manager ("ISM"), gas AMR PI Historian and Data Lake; (4) integrating to Mobile Collectors ("MC3s"); (5) testing the software, data migrations, and integrations; (6) educating and increasing the skills of the employees to leverage the new cloud services; and (7) decommissioning FCS and Itron Mobile and the on-premise databases and servers.

  - **Alternatives:** Alternatives considered included: (1) continuing to use the FCS application and Itron Mobile without vendor support. This alternative was not selected because it would add application stability, security, and dependency risks to gas meter reading data collection which would negatively impact critical customer billing operations. It would also de-couple from the Itron security infrastructure that the other business critical Itron applications use, creating more expense and complexity in the

technology environment. (2) Replace the platform with a different mobile gas reading application, which would also require the Company to replace the 1.2 million gas communication modules on the meters. Replacing FCS would require the application business owners to undertake a large initiative requiring multiple years to implement and a multi-team effort from start to finish. It would also increase the amount of technology needed to be supported and add cost to support as it would be a standalone product. (3) Move to Itron's Cloud technology (Temetra and Temetra Mobile). This option best suits customers and the Company's needs for the future as it offers new functionality while maintaining the system integrated into the Itron Security infrastructure and with the other Itron software products in use at the Company.

- The **SAP Support Pack Upgrade 2026** project requires $329,041 in O&M in the test year.

  - **Description:** The SAP Support Pack Upgrade project is to maintain the currency levels of all SAP applications. This will ensure the applications are at version levels that are supported by SAP, have the latest patches and bug fixes, and provide cross-application compatibility for the Company's business partners.

  - **Problem Statement:** To continue to maintain SAP application version currency, across all applications, the support packs released by SAP must be routinely applied. Without maintaining application currency, the core business applications running on the SAP platform are at risk of losing vendor support, resulting in the inability to apply bug fixes and patches, including security patches, and maintain application interoperability and stability.

  - **Objectives:** The project will add value by: (1) maintaining supportability of SAP applications; (2) mitigating system security, stability and reliability risks by ensuring the applications are up-to-date with the most current patches and bug fixes released by SAP; and (3) ensuring ongoing cross-application compatibility.

  - **Scope:** The scope of this project includes routine support pack upgrades to all SAP applications, which include: Enterprise Core Component ("ECC"), Customer Relationship Manager ("CRM"), Enterprise Portal, Process Orchestration ("PO"), Business Warehouse ("BW"), Business Objects ("BOBJ"), Data Services ("DS"), Solution Manager, Data Quality Manager ("DQM"), Graphical User Interface ("GUI"), Single Sign On ("SSO"), System Landscape Directory ("SLD"), and other related SAP applications.

  - **Alternatives:** Alternatives considered include: (1) Divide the scope into individual projects by SAP application. This alternative was not selected because the efforts are interrelated and completing them separately could

lead to duplication of work, especially testing efforts, and therefore potentially higher costs. (2) Migrate to SAP S/4HANA. This option was not selected, because SAP S/4HANA is a multi-year project that is not expected to be completed by year-end 2026. So an alternative approach is needed to perform the application upgrades and maintain currency in the meantime. (3) Balance the project scope through regular support pack upgrades. This alternative was selected because it provides the best balance of minimizing cost and maintaining support by combining multiple application upgrades through a single support pack upgrade effort.

- The **SiteCore Primary Upgrade 2025** project requires $6,099 in capital ($4,879 ROM Adjusted Capital) and $15,195 in O&M in the test year.

  - **Description:** The project will refresh all components of the website hosting, delivery, search, and analytics applications to add new features and improve search capabilities. Sitecore is the content management application for the consumersenergy.com website.

  - **Problem Statement:** Sitecore is currently operating on version 10.3, which is due to end mainstream support at the end of 2025. If this occurs, there will be an increase in support and maintenance fees of 10% above the annual subscription spend.

  - **Objectives:** The project will add value for the Company by: (1) avoiding costs for extended maintenance agreements required at the end of mainstream support; (2) ensuring that the website retains the most up-to-date security posture; and (3) supporting the Company's goals by improving reliability and performance.

  - **Scope:** The project scope includes: (1) upgrading the Sitecore content management software to include content hosting and delivery allowing the use of new features and functionality; and (2) migrating the Sitecore platform to the most up-to-date hardware and software by refreshing the application and database servers to a newer version of Windows Server and SQL Server.

  - **Alternatives:** Alternatives considered include: (1) Delay the upgrade. This alternative was not chosen due to the current version falling outside of the mainstream support window, requiring an additional 10% in maintenance fees. Along with rapidly changing feature sets that are continually being developed by the vendor, the Company would be in a worse position to handle constantly changing cyber threats; (2) Undergo a full website redesign. This solution was not chosen as a similar effort is already slated to begin in 2024; and (3) Upgrade Sitecore on a two-year cycle. This alternative was chosen as it provides up-to-date functionality, stability, and mitigates cyber security risks while minimizing cost and impact.

- The **Software Platform Refresh** project requires $42,219 in O&M in the test year.

  - **Description:** The Software Platform Refresh project will upgrade server operating systems, hypervisors, databases, and infrastructure platforms to retain low-cost vendor support.

  - **Problem Statement:** For systems that go beyond their normal manufacturer support ending, there will be increased support and maintenance fees of 20% to 100% above current support and maintenance depending on vendor. Completing this project allows the organization to (1) avoid high support costs; (2) provide for system security; and (3) stay current to promote seamless interoperability among servers, applications, and databases. Aging servers are more susceptible to security vulnerabilities and performance issues that ultimately could affect the business and customers.

  - **Objectives:** The project will add value for the Company by: (1) avoiding costs for special maintenance agreements required at the end of normal manufacturer support; (2) ensuring reliability and compliance with Information Security requirements; (3) improving data center environment stability; and (4) avoiding the need for high risk upgrades that cross multiple versions.

  - **Scope:** The project scope includes: (1) upgrading operating systems and databases on servers that are near end of support with a given vendor; and (2) maintaining hypervisors at the current version for stability and performance.

  - **Alternatives:** A funding options matrix was completed to review the potential alternatives. The alternatives identified were: (1) Complete the full scope of the solution for $1 million in order to eliminate the need for ongoing extended support; (2) Reduce the scale of the solution, which requires $1.6 million in ongoing extended support; (3) Reduce the scale of the solution even further, which requires $2.4 million in ongoing extended support; (4) Do not complete a software platform refresh, which requires $3.3 million in ongoing extended support. Alternative 1 was selected as the most cost effective solution to ensure ongoing system stability; seamless integration; and mitigation of cyber-security risks without the significant cost of extended support necessary for End of Life software systems.

**Q. Please describe Confidential Exhibit A-23 (SHB-8).**

A. Confidential Exhibit A-23 (SHB-8) is a confidential exhibit that provides Application Currency Program projected capital and O&M spend and scope for each of the Application Currency projects. Specifically:

- Column (a) provides the application name;
- Column (b) provides a disaster recovery Tier, where applicable;
- Column (c) provides total projected 2025 capital expenditures;
- Column (d) provides total projected 2025 O&M expense;
- Column (e) provides total projected 2026 capital expenditures;
- Column (f) provides total projected 2026 O&M expense;
- Column (g) provides total test year capital expenditures;
- Column (h) provides total test year O&M expense;
- Column (i) provides the gas allocation for test year capital expenditures; and
- Column (j) provides the gas allocation for test year O&M expense.

Application Currency information can be used to exploit known security vulnerabilities; therefore, the exhibit is confidential.

**Q. How does the Company decide which applications to include in the Application Currency Program for the test year?**

A. The Application Currency Program focuses on upgrades that maintain security and reliability of the application and underlying platforms, as well as maintaining vendor supported software versions. Not every application requires an upgrade each year, so the application data provided in Confidential Exhibit A-23 (SHB-8) is not inclusive of all

applications that are in upgrade cycles beyond the test year. The Company considers the following when determining the next upgrade version:

- Compatibility with the current environment and underlying platforms;
- Compatibility with associated or integrated applications;
- Future planned changes that could sub-optimize the application;
- Cyber security drivers and requirements;
- Additional functionality offered with the new version; and
- Availability of the appropriate version.

The applications meeting the criteria for upgrade are then added to the application currency list, cross-checked against other current or future projects that may impact the upgrade, and then scheduled.

**Q. Please explain the Application Currency projects.**

A. The following describes the Application Currency projects:

The **Application Currency - Capital** and **Application Currency - O&M:**

- **Description:** These initiatives will utilize capital and O&M funding to keep applications current for security and reliability. O&M is included with capital projects to complete expense activities associated with capital upgrades.
- **Problem Statement:** The Company manages a large number of applications in the technology landscape that require regular version upgrades to maintain vendor-supported software versions. Without vendor supported versions, the Company loses the ability to receive version updates and upgrades to address defects, patch security vulnerabilities, protect against cyberthreats, protect data, and add new features. Failure to upgrade these applications can have a direct negative impact on key customer and business processes, increase support costs, increase unplanned outages, and increase cyber security vulnerabilities.
- **Objectives:** Maintaining the appropriate versions of applications through application currency upgrades adds value by: (1) enabling the Company to maintain vendor support; (2) remediating vendor security vulnerabilities and enhancing security protections; (3) addressing vendor defects that impair stability and functionality, leading to fewer incidents due to outdated software;

and (4) addressing version interdependencies and compatibility between systems. This is essential to delivering safe, reliable, and affordable service to the Company's customers. The application upgrades in scope are regularly prioritized based on considerations that include application criticality; number of versions behind the current available version; security and operational risk; operational impacts of performing the upgrade; ability to defer; and cost.

- **Scope:** The scope of upgrading these applications encompasses: (1) upgrading the application software; (2) assessing any new functionality for value to the Company; (3) making necessary configuration changes; (4) testing the upgraded software; and (5) updating documentation related to the integration changes.

- **Alternatives:** Applications are routinely evaluated to determine if and what upgrade efforts are necessary to maintain an appropriate level of currency, as well as the priority of those efforts. During that review, the alternative of delaying the timing of the individual upgrades is considered based on: (1) maintaining an optimal balance between keeping the application current and risking failure; (2) an increased number of incidents; (3) paying increased support costs; and (4) preventing employees from performing their daily tasks. This project makes ongoing upgrades and support for these applications possible and fortifies the Company's ability to keep the large number of applications in the technology landscape secure and operational through upgrades. Without these upgrades, the Company will fall further behind in maintaining vendor-supported software versions, increasing the cost and complexity of the upgrade in the future.

Specific spend requirements for each Application Currency project are indicated in the table below and supported with additional detail in Confidential Exhibit A-23 (SHB-8).

| Project | Projected Test Year Capital | ROM Adjusted Test Year Capital | Projected Test Year O&M |
|---|---|---|---|
| Application Currency-Corporate-Capital | $54,038 | $43,230 | $5,972 |
| Application Currency-Corporate-O&M | $0 | $0 | $123,245 |
| Application Currency-Customer-O&M | $0 | $0 | $55,307 |
| Application Currency-Electric & Gas Shared-Capital | $109,408 | $87,527 | $18,064 |
| Application Currency-Electric & Gas Shared-O&M | $0 | $0 | $227,608 |

| | | | |
|---|---|---|---|
| Application Currency-Gas-Capital | $30,458 | $24,367 | $0 |
| Application Currency-Gas-O&M | $0 | $0 | $231,653 |
| Application Currency-IT/Digital Foundation-Application Platforms-Capital | $51,388 | $41,110 | $66,220 |
| Application Currency-IT/Digital Foundation-Application Platforms-O&M | $0 | $0 | $95,756 |
| Application Currency-IT/Digital Foundation-Infrastructure Platforms-O&M | $0 | $0 | $13,128 |
| Application Currency-Operational Technology-Capital | $46,318 | $37,055 | $17,199 |
| Application Currency-Operational Technology-O&M | $0 | $0 | $107,459 |
| Application Currency-Security-Capital | $45,951 | $36,761 | $3,604 |
| Application Currency-Security-O&M | $0 | $0 | $121,386 |

**Enhancement Projects**

**Q. Please describe Exhibit A-24 (SHB-9).**

A. Exhibit A-24 (SHB-9) is the Projected Versus Actual Enhancement Capital Expenditures and O&M Expense Summary and Analysis. Page 1 provides a summary of enhancement projected and actual spend for the years 2019 through 2026. Specifically:

- Column (a) provides the year reference;
- Column (b) identifies the gas case where the projected or actual amounts were provided;
- Column (c) identifies the exhibit number where the projected or actual amounts were provided;
- Columns (d) through (k) identify the projected or actual capital amounts for each year; and
- Columns (l) through (s) identify the projected or actual O&M amounts for each year.

Page 2 provides an analysis of total actual and projected enhancements, total incremental annual worklist of enhancements, total annual demand, total Company cumulative worklist, and gas allocation cumulative worklist. Specifically:

- Column (a) identifies the categories used for analysis, where total amounts include both capital and O&M;
- Columns (b) through (i) identify the projected or actual amounts by year; and
- Column (j) identifies the projected amounts for the test year.

Total gas Actual and Projected amounts are derived from Exhibit A-24 (SHB-9), page 1, which are the source for the figures indicated. Total Company incremental annual worklist, Exhibit A-25 (SHB-10), is defined as the total Company cost of planned enhancement requests received in the year indicated. Total gas allocation incremental annual worklist provides the gas allocation of the total Company incremental worklist. Total gas annual demand is defined as the total fulfilled and unfulfilled enhancement demand for the year, calculated by the sum of total gas Actual/Projected spend and Total Gas Allocation Incremental Annual Worklist. Total Company Cumulative Worklist is defined as the year-over-year increase of unfulfilled enhancement requests. Total Gas Allocation Cumulative Worklist provides the gas allocation of the Total Company Cumulative Worklist.

**Q. What is the purpose of Enhancements investments?**

A. Enhancements are smaller, short-cycle technology efforts to implement new or improved functionality and provide the flexibility needed to respond to rapidly changing business and customer conditions. Enhancement requests typically emerge from new or changing business conditions, compliance requirements, customer feedback, automation efforts, waste elimination efforts, and other improvement ideas. Enhancements benefit customers

and the Company through cost savings, cost avoidance, productivity improvements, safety improvements, efficiencies, mandated regulatory changes, and improved customer experience.

**Q. Please describe Exhibit A-25 (SHB-10).**

A. Exhibit A-25 (SHB-10) is the Enhancement Worklist Detail Report. It provides a summary of the Enhancements queue of work requests. Specifically:

- Column (a) provides the Enhancement open date, internally referred to as the Open Date of the request;
- Column (b) identifies the Number, which is used to internally track the lifecycle of the Enhancement request;
- Column (c) identifies the Type of request;
- Column (d) provides a Description of Work;
- Column (e) provides the Work State of Submitted, Screening, Qualified, and Approved;
- Column (f) provides the Portfolio that has requested the enhancement;
- Column (g) identifies the Associated Application, which is internally referred to as the Configuration Item, and is the application that will be changed with the Enhancement;
- Column (h) identifies the internal Requestor Department;
- Column (i) provides the Total Estimated Hours, which reflects the planning estimate of work hours entered prior to the start of work request; and
- Column (j) provides the estimated Cost.

**Q. How does the Company track and manage enhancements?**

A. The Company actively maintains a worklist of enhancements, Exhibit A-25 (SHB-10). Each enhancement is tracked in detail from idea to completion including steps for value justification, estimation, prioritization, final funding approval, execution, and closure. For an enhancement to seek funding approval, it must be qualified with a cost estimate and

benefits to ensure the enhancement is ready for execution. Once approved for funding in cross-functional business team reviews, the enhancement is scheduled. When the enhancement begins execution, the status for enhancement records is updated by enhancement request coordinators through closure. This provides the Company with an auditable tracking method for every enhancement request.

**Q. Please explain the historical demand for enhancements and the Company's projection for future enhancement demand.**

A. The demand for enhancement efforts has grown an average of 49% over the past three years because of the increased need for automation efforts, focus on waste elimination and cost optimization, additional functionality requests to optimize aging applications, and enhanced functionality requests for newly implemented technology.

As of October 2024, the Company has a worklist (Exhibit A-25 (SHB-10) of 639 requests Company-wide to improve multiple applications and systems. This well-known worklist demonstrates the high volume of demand for smaller technology efforts. Despite exceeding the projected spend in several previous years, the Company is unable to keep up with the growing demand for enhancements, as shown on Exhibit A-24 (SHB-9), page 2. The projected Total Gas Allocation Cumulative Worklist (Demand) for the test year is $7,577,721 (Exhibit A-24 (SHB-9), page 2, line 7, column j), while the Company is projecting $7,416,712 of Total Gas Projected Spend (Exhibit A-24 (SHB-9), page 2, line 2, column j). To recognize this increasing demand and better project Enhancement costs, the Company is projecting these costs by determining incremental enhancement demand for 2025 and 2026 based on a known worklist, plus applying a

combination of historical demand and historical spend. The projected level of demand still outpaces projected spend, as indicated above.

**Q. What methods is the Company using to ensure projected enhancement expenditures and expenses in the test year are reasonable and prudent?**

A. The Company is using two methods to validate enhancement demand expenditures and expenses in the test year: (1) three-year historical average and (2) total cumulative demand. For the three-year historical average method, the Company calculated the actual three-year historical average for 2022-2024 of $4,848,979 plus know incremental work of $3,117,727 ($7,966,706) and compared it to the projected Test Year enhancement expenditures and expenses of $7,416,712. This validates Test Year projections are in line with historical spending and known incremental work. Then for the total cumulative demand method, the Company compared the Total Gas Allocation Cumulative Worklist amount of $7,577,721, in Exhibit A-24 (SHB-9), page 2, line 7, column j, to the projected Test Year enhancement expenditures and expenses of $7,416,712. This comparison validates these projections are in line with the projected demand.

**Q. Please further explain the Company's calculation for the cumulative worklist amount.**

A. Projections for the total cumulative worklist in 2025 and 2026 are based on the three-year average annual increase to enhancement demand. As indicated, cumulative enhancement requests grew at an average annual rate of 49% over the past three years. As a result, the cumulative worklist for enhancements (Exhibit A-25 (SHB-10)) continues to grow year over year, as depicted on Exhibit A-24 (SHB-9), page 2, row 7. Validating the projected Enhancement spending based on a known worklist and a three-year historical average of

actual spend is an indication that the Company's test year projected spend of $7,416,712 is reasonable and prudent.

**Q. Please explain the Enhancements projects.**

A. The following are the Enhancements projects:

- The **Enhancements - Capital** and **Enhancements - O&M** requires the capital and O&M in the test year as described in the table below.
    - **Description:** These projects will utilize capital and O&M funding to make enhancements to existing software and to address requests generated by changing business requirements. O&M is included with capital projects to complete expense activities associated with capital enhancements.
    - **Problem Statement:** As business processes improve and change, new requirements surface that call for smaller-effort software application changes that typically emerge from new or changing business conditions, compliance requirements, needs for new capabilities, customer feedback, and other improvement ideas. Enhancing applications requires a short timeframe between inception and implementation and cannot and should not wait for rate case approval at an individual line-item level. Failure to make these changes to applications can have a direct negative impact on key customer and business processes, increase support costs, and limit the Company's ability to consistently meet objectives.
    - **Objectives:** The value of software enhancements lies in: (1) cost savings and cost avoidance; (2) technology and business process efficiencies; (3) improved customer experience; (4) risk mitigation; (5) safety improvements; and (6) achieving corporate goals, among others. While these small-work software efforts are neither projects nor operational work, funding for resources is still required to maintain business agility in the digital environment. Included in the implementation are small changes and functionality improvements to existing IT software application investments for the respective business areas.
    - **Scope:** The scope of application enhancements encompasses: (1) making necessary system changes; and (2) updating documentation related to the changes. Additionally, enhancement requests are fulfilled to provide new functionality for business areas represented by each program.
    - **Alternatives:** Prior to implementing an enhancement, a review is completed to identify the best solution. During that review, requests for this funding are governed by a cross-functional board comprised of

representatives from each area that routinely evaluates and prioritizes the work and to assess requests for value using categorized benefits. In addition, the overall enhancements budget is reviewed annually, and the alternative of a zero-budget allocation for enhancements is considered. This project fortifies the Company's ability to make software changes as part of process improvements and regulatory changes, and to meet legally required system changes. Without funding for enhancements, the Company will be limited in its ability to quickly provide needed capabilities and improvements.

Specific spend requirements for each Enhancement project are indicated in the table below.

| Project | Projected Test Year Capital | ROM Adjusted Test Year Capital | Test Year O&M |
|---|---|---|---|
| Product Family Enhancements-Corporate-Capital | $968,872 | $0 | $164,000 |
| Product Family Enhancements-Corporate-O&M | $0 | $0 | $176,642 |
| Product Family Enhancements-Customer-Capital | $1,928,428 | $0 | $287,903 |
| Product Family Enhancements-Customer-O&M | $0 | $0 | $161,549 |
| Product Family Enhancements-Electric & Gas Shared-Capital | $266,622 | $0 | $24,296 |
| Product Family Enhancements-Electric & Gas Shared-O&M | $0 | $0 | $68,261 |
| Product Family Enhancements-Gas-Capital | $1,382,825 | $0 | $165,688 |
| Product Family Enhancements-Gas-O&M | $0 | $0 | $239,401 |
| Product Family Enhancements-Application Platform Services-Capital | $300,361 | $0 | $103,023 |
| Product Family Enhancements- Application Platform Services -O&M | $0 | $0 | $53,515 |
| Product Family Enhancements-Infrastructure Platform Services-Capital | $207,502 | $0 | $66,113 |
| Product Family Enhancements-Infrastructure Platform Services-O&M | $0 | $0 | $109,219 |
| Enhancements-Security-Capital | $287,031 | $0 | $53,891 |
| Enhancements-Security-O&M | $0 | $0 | $123,761 |

**Digital Foundations and Capabilities Projects**

**Q. Please explain the Digital Foundations and Capabilities projects.**

A. Below are the Digital Foundations and Capabilities projects:

- The **Data & Analytics Platform Rationalization** project requires $1,228,844 in capital ($983,075 ROM Adjusted Capital) and $240,126 in O&M in the test year.
  - **Description:** This project will optimize the Data & Analytics system landscape by creating connections, migrating data into Data Lake 2.0 ("DL 2.0"), and building visualizations from the data in DL 2.0. Following the enablement of DL 2.0, retirement of the IT Data & Analytics legacy systems including SingleStore Data Lake ("SSDL"), SAP Business Warehouse ("BW"), BOBJ, Native HANA, the BW Portal, and SAP Business Objects Data Services ("BODS") creates value by reducing the total cost of ownership associated with maintaining and supporting legacy systems.
  - **Problem Statement:** The IT Data & Analytics legacy systems (SSDL, SAP BW, BOBJ, Native HANA, the BW Portal, and BODS) are outdated, inefficient, and becoming duplicative in nature with the introduction of DL 2.0. If these legacy systems are not retired, they will continue to cost the Company money as major investments are needed to maintain and support them.
  - **Objectives:** This platform rationalization project creates value for the Company and its customers by reducing the total cost of ownership associated with maintaining and supporting legacy systems including licensing fees, maintenance costs, infrastructure, and support resources.
  - **Scope:** The project scope includes: (1) the assessment of the existing Data & Analytics platforms including SSDL, SAP BW, SAP BOBJ, Native HANA, the BW Portal, and BODS; (2) inventory of data and reports still being used by stakeholders; (3) determination of migration strategy; (4) data migration to the Azure Data Lake; (5) report migration to Power BI; (6) organization change management; and (7) the retirement/decommissioning of the legacy platforms and applications.
  - **Alternatives:** Alternatives considered: (1) upgrade legacy systems in place (on-premise). This alternative was not selected because this is costly and misaligned with the Company's cloud strategy. (2) Lift and shift these on-premise systems to the cloud through the Hybrid Cloud Transformation Program. This alternative was not selected because it would duplicate the

work being done as part of the DL 2.0 project and would not provide the same efficiencies that DL 2.0 introduces. The alternative to migrate all data sources to DL 2.0 and retire legacy systems was selected because of the expected cost benefits and technology capabilities it provides to the Company over a timeline that allows the Company to realize the value of existing investments.

- The **Digital-Hybrid Cloud and Data Center Migration** project requires $93,044 in capital and $35,979 in O&M in the test year.

  - **Description:** This project will optimize data center assets and asset replacement project purchases by migrating or retiring applications out of existing Company and co-location data centers into cloud services, reducing operational costs for running IT services and leveraging increased cloud capabilities to improve the efficiency, quality, and speed-to-market of customer-facing and internal IT services.

  - **Problem Statement:** The technology currently deployed in the Company's data centers meets many customers' needs today. However, the pace of digital transformation is increasing rapidly, and requirements for applications are evolving faster than the technology in the Company's data centers can respond in a cost-effective manner. These data center constraints lead to longer implementation times, missing capabilities, or reduced functionality in the applications that the Company can deploy.

  - **Objectives:** This project will create value by ensuring the Company's technology requirements are met through a comprehensive and cost-effective combination of data centers and public cloud services. Specifically, by migrating applications to cloud services, the project will: (1) reduce capacity, hardware maintenance, and security device costs at the co-location data center; (2) reduce hardware maintenance and security device costs at the production data center; (3) enable the ability to scale infrastructure quickly up or down without costly up-front hardware purchases; (4) reduce application risk through cost-effective, scalable infrastructure redundancy and availability; (5) reduce ongoing server and storage asset replacement costs; (6) reduce ongoing networking equipment replacement costs; (7) reduce operational support costs; and (8) enable the use of a vast array of cloud services to support Company applications.

  - **Scope:** The project scope includes: (1) promoting the robust main co-location data center to become the primary data center for on-premise IT services; (2) demoting the Company's production data center to the disaster recovery data center for on-premise IT services; (3) analyzing applications for migration to cloud or retirement; (4) migrating applications from

on-premise to cloud; (5) transforming applications to use cost-effective cloud services; (6) altering network architecture and deploying base infrastructure to allow each location (on-premise or in cloud) to function independently; (7) deploying cloud and on-premise cost management tooling and processes; (8) simplifying and optimizing backup and disaster recovery resources and processes using cloud services; (9) implementing additional automation for application deployment and management; (10) changing the operations model for support of cloud-based applications; (11) educating and increasing the skills of IT and other employees in leveraging public cloud services; and (12) transforming IT to become the broker of cloud services for the Company.

- **Alternatives:** Alternatives considered included: (1) migrating to public cloud services faster. This alternative was not chosen because the Company's ability to absorb new technologies coupled with the investments the Company has already made in data center equipment would prevent a faster move from being efficient and effective, introducing additional financial risk; (2) migrating to public cloud services slower or not at all. This alternative was not selected because delaying public cloud services and capabilities coupled with requiring an extension of the life of existing data center equipment creates increased financial and operational risk; and (3) contracting with an outside vendor to provide cloud services to run applications for the Company. This alternative was not selected because industry information shows the option as not yet cost effective or not providing a maturity level that the Company would be able to easily consume with limited in-house experience and expertise in public cloud. The alternative to migrate to a hybrid cloud and data center model was selected because of the expected cost benefits and technology capabilities it provides to the Company over a timeline that allows the Company to realize the value of existing investments.

- The **OT Datacenter Migration** project requires $1,801,259 in capital ($1,441,007 ROM Adjusted Capital) and $ 716,473 in O&M in the test year.

  - **Description:** The OT environment consists of systems supporting the control and monitoring of electric grid, electric generation, gas compression, and natural gas pipeline. These systems are critical for safe and reliable natural gas and electric delivery. The OT Datacenter Migration project enhances the Company's capabilities by co-locating to an enhanced datacenter at a vendor facility.

  - **Problem Statement:** The Company's current datacenter for the OT environment needs modernization and relocation from the Parnall Data Center. The current location is not the preferred location to house servers

and systems critical to the control of the Electric Grid or Gas Pipeline due to the close proximity to a railway system. The climate conditioners in the current OT datacenter are aging and have had faults resulting in unplanned shutdowns. The location of the datacenter in the basement of the Parnall building is nearby to the main water piping for the building. There have been instances of water infiltration in the past.

- **Objectives:** This project creates value for the Company by significantly strengthening capabilities through: (1) mitigating legacy physical and location risks at the current Parnall site; (2) migrating the OT infrastructure to a modern, highly secured environment with redundancy in climate conditions; and (3) better datacenter facilities support with a guarantee of redundant power.

- **Scope:** The scope of the project includes: (1) migration of the OT environment from the Parnall Data Center to a co-located vendor data center; (2) re-validation of the OT Production and Disaster Recovery procedures once migration is completed; (3) migration of IT systems required for supporting the OT environment; and (4) decommission the existing OT environment from the Parnall location.

- **Alternatives:** The Company performed an analysis of alternatives to expand capabilities as well as address constraints and risks: (1) Remain at the current Parnall Data Center; (2) migrate OT environments to the Cloud; and (3) relocate to a third-party co-location facility. Current industry best practices do not recommend migration of OT environments to the cloud. The co-location vendor provides the building, cooling, power, and physical security the Company lacks for its servers, storage, and other computing and networking equipment at the current Parnall location. Based on the analysis, the Company decided to implement the third alternative.

- The **Spatial Asset Management** project requires $37,398 in capital ($29,918 ROM Adjusted Capital) and $6,635 in O&M in the test year.

  - **Description:** This initiative will implement SAP's Spatial Asset Management module. It will allow users to view assets, notifications, and orders geospatially using a map. The module will allow the Company to create and maintain asset maintenance plans for each segment of the Company's gas and electric distribution networks (linear assets). The Company will create linear assets as technical objects (such as functional locations and equipment) and store linear data. The Company will enable creation of maintenance plans for these technical objects which result in notifications, maintenance orders, and measurement documents. The Company will enable monitoring the condition of linear assets, identify where there is damage or a defect (using the start point and end point and

offset), and manage all types of maintenance tasks (planned, unplanned, and preventative).

- **Problem Statement:** Currently, the Company lacks spatial visualization and spatial awareness of work and assets impacting requirements for first time quality and impacting the ability to plan, bundle, and execute nearby work. The lack of a linear asset management capability affects the full work management value stream resulting in overproduction of asset maintenance activity such as assessments, surveys, and inspections.

- **Objectives:** This project creates value for the Company by (1) providing capability in SAP to view assets, notifications, and work orders on a map; (2) providing location awareness in SAP for assets and work; (3) establishing linear asset management capability in SAP for gas and electric delivery networks; and (4) enabling end-to-end map-based workflows.

- **Scope:** The scope of this project encompasses implementation in SAP of the Spatial Asset Management module.

- **Alternatives:** Alternatives considered include: (1) Implement a cloud-based individualized asset integration between GIS and SAP. This alternative was not selected as it proves ineffective in addressing needs of the end-to-end work management value stream while increasing the technical footprint of customization. There are also performance concerns with cloud to on-prem integrations; (2) Implement work group centric approaches to viewing work on a map. This alternative was not selected as it does not support standard operation through the entire work management value stream; (3) Do nothing. This alternative was not selected as this would result in increasing costs and inefficiencies in gas and electric work management; and (4) The alternative to implement the Spatial Asset Management module in SAP was chosen as it expands use of a core technology investment, supports current investment in the Company's work management value stream, and is compatible with our GIS technology.

**Q. Please explain the SAP HANA Database Migration project.**

A. The SAP HANA Database Migration project has the following synopsis:

- The **SAP HANA Database Migration** project requires $88,339 in capital and $25,464 in O&M in the test year.

  - **Description:** In preparation for SAP's planned end of support for its Business Suite product in 2027, the Company will migrate its existing SAP

databases from Oracle to SAP HANA in advance of the required move to S/4HANA.

- **Problem Statement:** The Company's SAP applications currently utilize Oracle's relational database management system as their underlying database storage technology. SAP has informed its customers that standard support for its legacy Business Suite (aka ECC) product will end in 2027, along with support for all non-SAP database platforms. SAP has also informed customers that the future direction for their enterprise solution is S/4HANA, a solution built explicitly for their HANA database platform. To prepare for these upcoming events, the company will migrate all of its SAP databases off of Oracle and onto SAP HANA.

- **Objectives:** This project lays the groundwork for the Company's eventual shift to SAP's HANA-based solutions by: (1) proactively migrating SAP databases to a database technology that is fully supported by SAP beyond 2027; and (2) mitigating the risk of a complete loss of support for the current Oracle database technology in 2027.

- **Scope:** Project scope includes: (1) procurement of HANA software licensing to cover all migrated SAP applications; (2) data migration for all SAP applications from the Oracle database to SAP HANA; and (3) implementation of new application support policies, procedures, and tools required to manage the newly migrated SAP HANA applications.

- **Alternatives:** Given SAP's announcement regarding the end of support for its ECC product in 2027, all customers running SAP on database software other than HANA will also lose support for their associated database software in 2027. SAP is offering no other options for databases other than HANA beyond 2027. While there is no alternative to the HANA database for SAP going forward, the Company has considered multiple options: (1) Perform a direct migration from SAP Business Suite on Oracle to S/4HANA. A direct migration to S/4HANA brings greater operational risk to the Company as both the underlying database technology and the SAP application's functionality would change simultaneously, so this alternative was not selected. (2) Remain on the current SAP Business Suite product but competitively bid support services to a third-party provider instead of SAP. This alternative was not selected because moving to a third-party support model forces the Company to remain on outdated SAP software and eliminates any possibility of benefitting from new business functionality provided by S/4HANA. It will also require the Company to accept significant risk due to the fact that SAP security patches, application patches and upgrades will not be available upon termination of the SAP maintenance agreement. (3) Migrate to SAP's SaaS implementation of S/4HANA. This alternative was not selected because an S/4HANA SaaS migration is a much more disruptive option as the Company's business processes must be adjusted to accommodate functionality differences

between ECC and S/4HANA. The risk of negative business impact is significantly greater than simply changing the underlying database technology. The selected alternative to migrate the SAP databases to HANA prior to implementing S/4HANA gives the Company several years to solidify its HANA database infrastructure before introducing the substantial business process changes required with S/4HANA.

**Q. What is the Company's migration timeline for the SAP HANA Database Migration project?**

A. The Company initiated the SAP HANA Database Migration project in April 2023 and is anticipated to be completed by December 2025. The migration will be staggered across 2024 and 2025. In 2024, the Company will migrate ancillary systems to HANA to gain valuable insight from these migrations and address any technical issues before migrating the ECC in 2025. This will also provide time to conduct mock migrations for ECC, which will help minimize downtime.

**Q. Please explain the SAP S/4HANA Implementation project.**

A. The SAP S/4HANA Implementation project has the following synopsis:

- The **SAP S/4HANA Implementation** project requires [redacted] in capital ([redacted] ROM Adjusted Capital) and [redacted] in O&M in the test year.
  - **Description:** This project will modernize the Company's current ERP SAP solution. Upon completion, the solution will provide enhanced functionality across several business areas while providing a supported and secure platform capable of business transformation**.**
  - **Problem Statement:** The current SAP ERP system will reach the end of mainstream vendor maintenance on December 31, 2027. Operating the system beyond the end of support date creates significant risks to comply with regulatory mandates, perform core customer supporting business operations, and apply the latest security patches that are critical for cyber protection against customer and employee data breaches. In addition, an unsupported platform limits improvement of operational efficiency and maintaining the stability, reliability, and security of the system.
  - **Objectives:** The S/4HANA program will position the Company for business transformation by enabling it to (1) provide and maintain

capabilities for protection of sensitive customer and employee data; (2) provide enhanced system stability and reliability needed in a 24x7 business by significantly reducing system maintenance outages; (3) mitigate the regulatory and operational risks of running critical business processes on an unsupported platform; (4) implement simplified workflows and standardized processes by reducing customizations; and (5) use in-memory computing with embedded real-time analytics to make smarter, faster decisions.

- **Scope:** The project scope includes (1) Migrating the current SAP ERP solution to the latest S/4HANA solution. This includes (a) moving to the latest version of the software, (b) migrating existing data to the new S/4HANA data model, (c) connecting interfaces from other systems into S/4HANA, (d) using newer user interfaces available in S/4HANA where feasible, (e) setting up users and user access in the new system, (f) migrating existing reports and analytics or replacing them with new in-built reports and analytics in S/4HANA, and [redacted] (2) Enabling an architecture that minimizes downtime for system maintenance activities. (3) Implementing solutions where existing SAP ERP functionality is not available in S/4HANA. (4) Implementing a foundational "clean core framework." This requires minimizing or remediating custom code and utilizing SAP customization best practices in the new version. These best practices will decouple the core SAP software from Company-specific customizations, hence making it "clean." This clean core framework is expected to reduce the effort and cost of upgrading SAP in subsequent releases.

- **Alternatives:** An analysis was completed that included key industry input, feedback from business areas across the Company, technology leaders, and subject matter experts. This presented the organization with several alternatives, including the following: (1) Postpone the decision and stay on the current version. This would require purchasing the extended maintenance until 2030 due to the current mainstream maintenance expiring in December 2027. A skill shortage is anticipated as SAP customers scramble to meet the 2030 deadline. Delaying our decision to migrate to S/4HANA would put the Company at a higher risk of securing those high-demand skilled resources. Staying on the current version beyond 2030 with third-party support would limit the Company's ability to continuously improve operational efficiency and maintain the stability, reliability, and security of the system. This alternative was not selected because of the additional cost and risk, and the inability for the Company and its customers to enjoy any added benefits or new application features. (2) Eliminate SAP and use multiple best of breed solutions in the various business areas. (3) Eliminate SAP and implement a new ERP solution. SAP is currently used across the Corporate, Work and Asset Management, and Customer areas. There are very limited options for a single ERP system that provides

all three areas of functionality. The current SAP system has over 100 satellite systems and around a thousand interfaces. Non-SAP alternatives may not work with current satellite systems, requiring the replacement or significant remediation of those satellite systems. These non-SAP alternatives would require a much larger change management initiative, significant reskilling of technical resources, and retraining of people across the Company who have become familiar with SAP over the last 16 years. Alternatives (2) and (3) are more expensive, complex to implement and support long-term, therefore were not chosen. (4) Migrate to the latest S/4HANA solution before the end of 2030. This option was chosen because it mitigates risks and provides a supported and secure platform capable of business transformation.

**Q. Describe the deployment approach the Company will utilize for the SAP S/4HANA Implementation project.**

A. The Company will deploy the migration to the new S/4HANA solution in phases to reduce the risk of operational impact to customers and co-workers. The Company will adopt SAP's standard Activate methodology for the deployment approach.[3] The Activate methodology includes six phases: Discover, Prepare, Explore, Realize, Deploy, and Run/Adopt. The Discover, Prepare and Explore phases result in the design, which is then built, tested, and deployed in the Realize, Deploy, and Run/Adopt phases. The approach is to design the system holistically, meaning the Discover, Prepare, and Explore phases will cover all modules of SAP, including Finance, Supply Chain, HR, Work Management, and Customer. This ensures the system is designed optimally from end to end. Once the design is complete, the Company will conduct multiple iterations of the Realize, Deploy, and Run phases to deploy functional modules in a staggered capability deployment approach.

[3] Available at https://learning.sap.com/learning-journeys/discovering-sap-activate-implementation-tools-and-methodology/describing-sap-activate

**Q. Please explain the different S/4HANA migration alternatives considered.**

A. The Company considered three migration alternatives: (1) Build a new SAP system without using any existing customizations, configurations, processes, or data (Greenfield); (2) Upgrade the existing SAP system, retaining existing customizations, processes, and data, then remediate errors that arise in the upgrade process in a series of iterations (Brownfield); and (3) Adopt a hybrid strategy, building a new SAP system, while selectively migrating critical data and process from the existing system (Bluefield).

**Q. Which S/4HANA migration approach has the Company selected?**

A. The Company has selected the hybrid or Bluefield approach for the S/4HANA Implementation project.

**Q. Why did the Company select the Hybrid, or Bluefield, migration approach for the S/4HANA Implementation project and not the others?**

A. The Company chose the Hybrid, or Bluefield, approach because it offers the best balance of lower risk and cost[4]. While the Greenfield option provides lower total-cost-of-ownership and faster time-to-value for implementations that want to shed a lot of legacy customizations and start afresh, this is not fully the case for the Company because the current system has many essential customizations in the customer billing and employee payroll areas that will need to be rewritten in the new system with this approach. Rebuilding customizations introduces significant risk and cost. Similarly, the Brownfield approach could provide a shorter project timeline by migrating all the current customizations and processes. However, this approach is not preferred in the Finance, Supply Chain, and Work Management areas where the current system has a lot of custom processes, workflows,

[4] Available at https://www.leanix.net/en/wiki/tech-transformation/s4hana-greenfield-vs-brownfield-approach

enhancements, and interfaces that are suboptimal compared to the standard best practice processes that come in S4/HANA. The Brownfield approach is also not preferred because the processes and data model in Finance and Supply Chain have changed significantly. Upgrading current customizations to the new system would not be easy and rewriting them would be expensive and increase risk. This would result in a new system that does not conform to SAP's clean core approach and would be expensive to upgrade in the future. Therefore, the ideal approach is a combination of the two where the new system adopts a Greenfield approach for Finance, Supply Chain and Work Management, and a Brownfield-like approach for Customer and Payroll.

**Q. Why is the Company undertaking the expense and effort of migrating to the SAP S/4HANA version at this time?**

A. Migrating to the SAP S/4HANA version is crucial for the Company because the mainstream support for our current SAP version ends in December 2027. After evaluating the project, the Company determined it will take approximately three years to complete. Assuming the Company begins the project in 2025, the timeline will extend into 2028, requiring the Company to purchase extended SAP support for 2028. It is important to note that extended support for the Company's current SAP version is only available until 2030.

**Q. Will the Company's SAP systems face an increased risk of cyber-attacks if the S/4HANA project is not executed?**

A. Yes. The Company's SAP systems will face increased risk of cyber-attacks if the S/4HANA project is not executed, because SAP has stated that after maintenance ends, standard patches will no longer be available for SAP customer-specific maintenance,

leaving the Company's SAP systems vulnerable to emerging threats from bad actors exploiting known vulnerabilities.[5]

**Q. Please explain whether the Company's SAP systems will continue to operate if the S/4HANA project is not executed?**

A. The Company's SAP systems will continue to operate with significant risk for an indeterminate period of time if the S/4HANA project is not executed. SAP will not support the Company's current SAP version after December 2027, when the mainstream maintenance ends. After this period, the risk of operational disruptions will increase significantly due to the lack of a Service Level Agreement with SAP, and there will be no guarantee that SAP resolve any new issues that arise.

**Q. How did the Company develop the cost estimate for the SAP S/4HANA Implementation project?**

A. The Company developed the cost estimate for the SAP S/4HANA Implementation project with the support of an independent third party that specializes in preparing for S/4HANA upgrades. The cost estimate consists of labor, contractor, software, and non-labor costs.

The labor and contractor cost estimates were derived as follows:

- First, the phases of the project were laid out in a timeline based on the phased deployment approach and Hybrid migration approach, both previously described in my testimony.
- Second, the high-level scope was identified, including the processes, pain points, customizations, integrations, roles, and data volumes that need to be migrated to S/4HANA.
- Third, the effort for the design and subsequent phases were translated into the number of hours and resources required for each phase. The resources are further broken down into roles and number of each role.

[5] Available at https://support.sap.com/en/my-support/knowledge-base/security-notes-news.html?anchorId=section_370125364

- Lastly, the resource estimates were assumed to be a mix of 30% internal employees and 70% external contractors. The Company then applied an average resource rate based on internal and external resources to calculate the cost estimate. For certain activities, the resource estimate was derived using a percentage of the overall effort based on best practices, e.g. program management and quality management.

- The software cost estimate was based on indicative Bill of Material ("BOM") from SAP.

- The non-labor cost estimates are based on business expense, and labor overheads based on projected internal labor and external contractor costs to support the project.

Finally, the Company conducted a comparison of peer utility overall cost estimates and duration for their S/4HANA implementation projects to validate the Company's overall cost and duration estimate was reasonable.

**Q. Why is this SAP upgrade more costly than the Company's previous upgrades?**

A. This SAP upgrade is more costly than the Company's previous upgrades for several reasons. First, the latest SAP S/4HANA version improves business processes, requiring the Company to thoroughly evaluate these best practices against existing processes. This evaluation is crucial in determining adoption and adds to the overall project cost.

Second, migrating data to the new system involves mapping, transforming, and testing data elements required by S/4HANA's new data model. Third, the Company must re-evaluate and update user access because the system controlling access permissions has changed in S/4HANA. Fourth, the existing solution has customizations that cannot be moved to the new system as-is due to the differences in business processes, data model, and permissions. Finally, SAP recommends customers adopt a "clean core" approach when customizations are necessary. This approach moves the customizations outside the core product, which makes future upgrades easier. This requires the Company to perform a detailed evaluation and remediation of existing customizations.

**Q. Would it be more cost-effective for the Company to replace its SAP systems?**

A. No. It would not be more cost-effective for the Company to replace its SAP systems. This would require re-engineering the entire SAP system to a new solution, assuming that the current system could be replaced with a single replacement. It would require significant effort to re-skill the Company's co-workers, re-engineer business processes, re-implement the system, and integrate the new system with all the systems currently interfacing with SAP. The Company currently has more than 1,000 interfaces to SAP. Replacing SAP with multiple systems would be more costly and introduce additional risk due to the complexity of managing multiple disparate solutions. The Company would need to develop integrations between systems like Finance, Supply Chain, Work Management, and Customer. These integrations are inherent in an integrated solution such as SAP.

**Q. Is the Company requesting any special rate-making treatment to amortize the cloud implementation costs for the SaaS solutions that will be a part of the SAP S/4HANA Implementation project?**

A. Yes. The Company is requesting to amortize the cloud implementation costs for the SaaS solutions that will be a part of the SAP S/4HANA Implementation project over a 15-year asset life. This software asset will provide significant value and functionality over an extended period, as it is deeply integrated into the Company's business processes, and there is a substantial investment in its development and integration. The benefits of continuing to use the existing software outweigh the costs of transitioning to new software sooner than 15 years. This approach will also benefit customers by spreading these costs over 15 years to minimize the impact on customer rates.

**Q. Please describe Confidential Exhibit A-26 (SHB-11).**

A. Confidential Exhibit A-26 (SHB-11) is the IT S/4HANA Cloud Implementation Costs balance for Gas and Common investments for the projected 13 months ending October 31, 2026. It provides a summary of the gas allocation of projected IT Department investments expenditures. Specifically:

- Column (a) provides the balance category;
- Columns (b) through (n) provide each month's ending IT S/4HANA Cloud Implementation Costs balance; and
- Column (o) provides the 13-month average of columns (b) through (n).

**Q. Please describe the purpose of Confidential Exhibit A-26 (SHB-11).**

A. The Company has identified cloud computing as a viable alternative for several technology solutions associated with the SAP S/4HANA Implementation project. As discussed previously, the Company is requesting to amortize the cloud implementation costs for the SaaS solutions that will be a part of the SAP S/4HANA Implementation project over a 15-year asset life and adjusting working capital. Cloud implementation costs are projected based on the planned implementations of the SaaS solution associated with the SAP S/4HANA Implementation project. This working capital adjustment is provided by Company witness Rayl on Exhibit A-12 (HLR-34), Schedule B-4.

**Q. Is the Company requesting any additional special rate-making treatment for the SAP S/4HANA Implementation project's Investments O&M expense?**

**A.** Yes. The Company is also requesting to defer the Investments O&M expense associated with the SAP S/4HANA Implementation project and recover the expense over the life of the asset. This approach will benefit the customers by spreading these costs over the life

of the asset to minimize the immediate impact on customer rates. This proposal will be discussed further in the direct testimony of Company witness Heidi J. Myers.

**Q. Please explain the IT Operations Management – Service Operations project that is new in this case in 2023 and 2024.**

A. The IT Operations Management – Service Operations project has the following synopsis:

- **Description:** This project will implement an application service mapping tool to effectively manage business-critical services through identification of infrastructure components and application interactions. This tool automates the mapping process to create a complete, up-to-date, and accurate record of the mapped application service in the Database. Application service mapping works hand-in-hand with asset discovery, building on discovered infrastructure data to identify all the assets that support a service, and along with their service-specific relationships.

- **Problem Statement:** As the IT systems steadily increase in complexity and evolve faster than the IT organization can respond to system issues in an optimized and cost-effective manner, the current configuration of the system does not provide the clarity needed in order to understand how the infrastructure interacts with the applications within the IT System it supports and in order to respond to emergent IT incidents in the most rapid and cost effective manner. These constraints can lead to lengthy response and implementation times; negligible or ineffective resolutions; reduced functionality; and elongated outage times in the infrastructure and applications in the system.

- **Objectives:** This project will create value for the Company by mapping critical application services through discovery of the underlying infrastructure associated with application services and its relationship to parent business applications. Specifically, by creating application service maps, this project will: (1) increase visibility and understanding between IT infrastructure and Configuration Items; (2) improve accuracy through real-time, automatically updated infrastructure and component changes; (3) reduce IT Subject Matter Expert time on emergent IT issues; (4) Utilize IT Service Management processes; and (5) Reduce downtime by identifying dependencies and impact analysis.

- **Scope:** The project scope includes: (1) implementation of on-premise application service maps which have significant business impact; and (2) establishment of process roles needed to support service maps built.

- **Alternatives:** Alternatives considered included: (1) Choose an alternate IT Operations Management System with Cloud capabilities. This alternative was

not chosen as it would require introducing and integrating an additional vendor product into the technical landscape. (2) Develop a custom solution. This alternative was not chosen since the cost to build and maintain similar capabilities and to integrate the custom solution would not be feasible or cost effective. (3) Do nothing. This alternative was not chosen as there would be a correlation gap between application services and the underlying infrastructure and would not address the ever-increasing resolution costs. (4) Develop and implement an on-premises service mapping and process solution. This alternative was chosen due to the value in IT Operations Management and its integration capabilities with other platform modules from the same vendor. It offers a unified platform that can utilize the Configuration Management Database ("CMDB") and work hand-in-hand with asset discovery.

**Q. Please further describe the value of the IT Operations Management – Service Operations project.**

A. The IT Operation Management – Service Operations project will reduce the time for resources to identify and troubleshoot critical incidents by 30%, which will result in avoided labor costs.

**Security Projects**

**Q. Please explain the Security projects.**

A. Below are the Security projects:

- The **Business Continuity - Program Management Tool** project requires $33,092 in O&M in the test year.
    - **Description:** The Business Continuity Program Management Tool is critical for successful and effective Business Continuity, Disaster Recovery, and Emergency Management Programs. The software tool will provide automation, enhance the Company's incident management processes, establish critical linkages between departments and essential functions they support, and will perform necessary analysis before, during, and after a disruption that allows for the efficient response to minimize downtime.
    - **Problem Statement:** The current business continuity and disaster recovery program management tool does not offer the capabilities to advance program maturity and to foster a world class response to a business interruption. The current tool limits automation opportunities which result in manual workarounds. The lack of capability affects reporting, upstream/downstream impact mapping, Incident Command System ("ICS") documentation automation, and user administration.

- **Objectives:** This project will create value for the Company by: (1) maintaining and/or promptly recovering critical processes and associated essential functions that, if disrupted, would present significant impact to the Company and customers; (2) limiting business and community impact while providing a critical energy service; (3) prioritization of the recovery of critical processes and resource allocation during a business continuity incident(s); (4) providing a consistent, organized, and expedient response process (ICS) that is flexible to meet the needs of any incident, regardless of severity or scope; (5) providing a mechanism for identifying restoration gaps between critical business processes and IT recovery capabilities; (6) reducing or eliminating human error and waste; and (7) improved and more efficient user experience.

- **Scope:** The project scope includes: (1) framework for the development and maintenance of Business Continuity, ICS, and Disaster Recovery Plans that are effective and easily accessible during an event; (2) automation for reporting to track status, to measure effectiveness and maturity of the program (Business Continuity, Emergency Management, Disaster Recovery Programs) and to facilitate effective response; (3) program management tools to monitor required program deliverables; (4) template for developing and maintaining site hazard assessments; (5) dependency mapping of critical business processes and IT applications; and (6) integrated business impact analysis process.

- **Alternatives:** Alternatives considered include (1) continue to use Castellan (current Disaster Recovery tool). This alternative was not selected because it currently does not offer the capabilities to advance program maturity and to foster a world class response to a business interruption. (2) Revert back to manual process. This alternative was not selected because the manual process is time consuming and leads to human struggle and duplicative work. A previous KPMG Audit of the Business Continuity Program indicated the need for interdependency mapping and a software tool is the best way to accomplish this. (3) Implement a best-in-class Cloud SaaS solution. This alternative was selected because there are many SaaS solutions that fit the needs outlined above. The final application will be determined after a Request For Proposal is issued and a vendor is selected in the project plan phase.

- The **Forward Web Proxy Services** project requires $1,173,788 in capital ($939,030 ROM Adjusted Capital) and $149,967 in O&M in the test year.

  - **Description:** This project will replace the current web proxy service platform with a new platform. A web proxy service is a type of proxy server that sits between a client and the internet. It acts as an intermediary that evaluates, modifies, and forwards the client's requests to the destination web server. This service offers many benefits for the Company such as advanced filtering. Advanced filtering in a forward web proxy service can

filter out unwanted or harmful content from the internet, such as malware and phishing. This can protect the client's device and network from cyberattacks and improve their browsing experience. Without advanced filtering, the Company's cyber assets are at risk of attacks such as ransomware.

- **Problem Statement:** The Company currently leverages an existing vendor platform for web proxy services that has been in existence since 2021. Since the implementation of the platform, it has caused ongoing operational issues related to web filtering and connectivity. When there is a degradation of service, Company employees and contractors are unable to access internet or cloud-based resources. As the Company continues its cloud and SaaS journey, it is imperative to provide consistent access and communication, while still protecting the Company from cyber threats.

- **Objectives:** This project creates value for the Company by (1) increasing service reliability for employees and contractors to internet and cloud-based resources; (2) utilizing technology to enable the Company to handle all types of different workloads from varying geographic locations and is highly available; (3) using a mature and scalable web proxy service provider; and (4) providing Zero Trust by continuously verifying every connection request.

- **Scope:** The project scope includes: (1) replacing the current web proxy services solution and implementing a new system; (2) replacing physical web proxy hardware; and (3) potentially changing SaaS cloud vendors.

- **Alternatives:** The Security team did extensive research on alternative web proxy services solutions. Alternatives considered include: (1) continue to use and maintain the current web proxy services platform. This alternative was not chosen due to the consistent operational issues with the platform that make it unreliable. The result of an unreliable system means that employees and contractors are unable to access business critical services such as email, Teams, ServiceNow, and SharePoint Online; (2) route all internet traffic through the Company's corporate data center. This alternative was not chosen because the capabilities of firewalls are not as effective in stopping sophisticated cyber-attacks as using a web proxy service; (3) replace current system with modern vendor platform for web proxy services. The option that was chosen is to replace the current solution with a new system. This option was chosen because it offers additional features such as browser isolation (the ability to contain web pages so that the web page cannot affect the client workstation) and sandboxing (a way to safely execute malicious applications without impacting the Company's network). As part of the evaluation, the Company reassessed based on outside advisors and industry trend analysis, focusing on the ability to execute and the vendor's capabilities.

- The **Physical Access Management and Alarm Response** project requires $846,948 in capital ($677,559 ROM Adjusted Capital) and $101,685 in O&M in the test year.

  - **Description:** The project will replace the Company's Physical Access Management System to establish a centralized platform that manages user identities, authenticates users, authorizes access, and audits user activities. The intent of this project is to consolidate and modernize the Company's physical security systems that will enable enhanced security monitoring to prevent unauthorized entry into sensitive corporate areas while providing increased flexibility to the Company's valued employees and contractors.

  - **Problem Statement:** The Company's Security Fusion Center (the Fusion Center is the Company's combined physical and cyber security operations center) is experiencing operational issues with the current physical access management system. The installation is out of date and causes inconsistent behavior when given tasks by automations within the Company's Identity Management solution. Frequent issues have been reported related to frozen jobs in the Company's existing access management solution due to the current system's database. This results in significant waste in the form of (1) waiting, the business partner is waiting much longer than they should have for the system to process their request as un-freezing jobs is a manual process; (2) lost productivity, that waiting can cause for the business partner as it can either prevent them from accessing sites they need, or slow them down unnecessarily while they work with others to be escorted; (3) rework, because frozen jobs do not always run correctly when unfrozen, meaning the business partner has to resubmit their request and/or Identity Operations has to do additional work to satisfy the original request; and (4) alarms can cause a frozen state that impact system stability and reduces security visibility as a result. Not moving to new technology also carries a growing risk of outright system failure which could result in unauthorized physical access and/or impact the Company's ability to efficiently function. The current installation of the physical access management system and the Company's current card readers do not support next generation physical access control methods, such as digital ID. This prevents the Company from adopting new methods and practices that can lower costs and improve control and responsiveness. All employees, contractors, staff, and visitors are impacted by the problem.

  - **Objectives:** This project creates value for the Company by: (1) developing an alarm and event monitoring system, which will enable seamless orchestration of system alarms and cameras; (2) adding automation that will streamline remediation processes and orchestrate camera operations for efficiency; (3) refining access revocation and badge access management to ensure only authorized personnel have entry privileges; and (4) introducing new access control readers that will modernize the system, allowing for the use of mobile device badges for employees, contractors, and visitors,

offering a more flexible and user-friendly experience for those entering the Company's facilities.

- **Scope:** The project scope includes modernizing the Company's current physical access control system, badge system, badge access hardware and firmware, and all 3000 card readers across facilities and assets. This will require modernization of all physical badge access readers and the implementation of hardware and software necessary to run the physical access control system. In addition, there will be substantial automation and integration between the security orchestration solution and the physical access control systems to realize the full benefits of this initiative.

- **Alternatives:** Alternatives considered were: (1) Keeping the current physical access control system and processes as-is. This alternative was not selected as the current platform is outdated, increasingly expensive to support, and does not include modern capabilities, such as digital IDs. It also does not reduce waste, cost, and it does not improve speed to delivery; (2) Developing a custom, in-house physical access control solution that includes modern capabilities, such as digital IDs. This option was not selected as the Company lacks the expertise to build such a solution. Custom-developed solutions have higher long-term, and generally result in significant waste, as well as lower speed to delivery; and (3) Implementing a new physical access control system that includes modern capabilities, such as digital IDs, that reduces waste and cost and improves speed to delivery. There are vendors in the market that specialize in physical access control systems that offer proven capabilities the Company is looking to implement. This option was selected as it will allow the Company to meet its objectives of lower waste, lower cost, improved speed to delivery, by implementing digital IDs and enabling tighter integration between the physical access control system and the Company's other security platforms.

- The **Saviynt Enterprise Identity Governance and Access ("EIGA") Implementation** project requires $347,456 in capital and $46,637 in O&M in the test year.

  - **Description:** The project will implement Saviynt EIGA module, consolidate Identity Access Management ("IAM") functionality into Saviynt, and retire the Identity Manager application. By implementing the new solution, the Company will optimize IAM functionality, eliminate complexity, and reduce support costs. In addition, the project will integrate the OT network with an IAM solution that will allow for automated management of users and entitlements in the OT Active Directory domains and applications**.**

  - **Problem Statement:** The current version of AccessNow reached end-of-life in December 2022, with support discontinued in January 2023. The application has numerous custom workflows and integrations,

requiring professional services for ongoing use and changes. It lacks proper data analytics and reporting, posing risks such as inability to fix critical defects, software incompatibility, compliance issues, increased costs, and degraded performance. The Company uses multiple IAM tools, each performing critical functions, leading to numerous required interfaces and customizations. While beneficial for end users, these integrations increase the risk of system failures, higher support costs, multiple subscriptions, infrastructure and maintenance costs, and more expensive upgrades. The current solution utilizes SAP HR batch file processes that introduces failure points, delays, and data integrity issues. Failures in these processes can prevent new or transferred employees from accessing necessary systems, leading to operational disruptions and potential compliance risks due to inappropriate access retention.

- **Objectives:** This project provides value by: (1) Consolidating multiple IAM platforms through the implementation of the Saviynt EIGA Module, reducing complexity and support costs; (2) Decreasing complexity and enhancing efficiency by reducing interfaces between multiple identity tools; (3) Improving the end-user experience and reducing human struggle with access requests through a new, intuitive portal design; (4) Minimizing custom code and focusing on configurations only by utilizing out-of-the-box functionality; and (5) Streamlining employee data processing with the implementation of an HR interface.

- **Scope:** This project scope includes: (1) Implementing the Saviynt EIGA module to consolidate IAM platforms; (2) Standardizing processes by removing customized code and using out-of-the-box functionality; (3) Replacing and improving access system; (4) Addressing issues with aging applications, multiple IAM platforms, integration challenges, and antiquated HR processing.

- **Alternatives:** Alternatives considered include: (1) Implementing hot fixes to AccessNow version 8.1.5 to ensure support through mid-2023; (2) Upgrading only the application to current supported version, excluding the new web portal but will include new application functionality; (3) Remaining on current version that will be unsupported as of January 2023, requiring vendor professional services for any break / fix. Patches and enhancements may potentially introduce additional risk of version instability; (4) Implementing IAM functions in Saviynt platform to manage access requests, including Active Directory, SAP, SAP HR, disconnected systems, and existing API integrations. The alternative selected was implementing the new Saviynt system, eliminating AccessNow software.

- The **Security Threat Intelligence Tool** project requires $190,774 in capital ($152,619 ROM Adjusted Capital) and $31,781 in O&M in the test year.

- **Description:** This project will implement a threat intelligence application that will actively assess physical and cyber threats in the environment, visually display historical and active threat data for situational awareness and provide alerts to employees based on location of the threat. This information will allow the Company's combined physical and cyber security operations center (Fusion Center) to alert employees who are in the proximity of a physical threat on the risks they may face, help inform decisions on hardening facility locations and alert employees of active cyber threats that are currently impacting other companies. The ability to proactively alert employees of the threats will have a positive impact on Safety and Cyber Security for the Company by reducing response time to incidents and reduce the likelihood an employee will be physically injured.

- **Problem Statement:** The Company's Fusion Center and Physical Security teams currently do not have the ability to actively collect or disseminate threat intelligence in real time. This gap in technology increases the risk of physical and cyber-crime to employees and Company assets. As the threat landscape changes, automating data collection is essential to detecting and determining threats in real time. Currently the Company's Fusion Center manually searches through sources to collect threat intelligence. The data that is manually collected is often out of date by up to one week. This re-active approach has led to gaps in information and the inability to accurately depict the threat environment. Relying on manual processes and stale data can result in employees to be put in threatening situations. Cyber threats change daily in the environment. Spending valuable time to search manually through threat information causes delays in protecting the Company's sensitive data including electric and gas critical infrastructure, financial, and customer data.

- **Objectives:** This project creates value for the Company by: (1) Implementing a threat intelligence tool that actively assesses threats in the environment; (2) Visually displaying historical and active threat data for situational awareness; and (3) Providing alerts to co-workers based on their location. Accurate and timely information about threat actors and their tactics enables the team to proactively perform targeted investigation, containment, and remediation.

- **Scope:** The project scope includes: (1) Implementing a single threat intelligence application that will provide intel on both physical and cyber threats; (2) Integrating with the current security orchestration platform; and (3) Building automation to notify co-workers of physical threats that are identified through intel provided in the application.

- **Alternatives:** Alternatives considered include: (1) Maintaining the Company's current security posture of manually gathering information on threats through social media, law enforcement, and news reports. Continue to alert employees of active threats once they are noticed by Fusion Center

employees. This alternative was not selected because the process to gather the data is completely manual and the data gathered can be outdated by up to a week. Stale data can put Company assets and employees in dangerous situations. Using outdated information delays response time for Company crews and law enforcement to address the situation. (2) Expanding the Company's current mass notification tool use to integrate security threat intelligence intel. This alternative was not selected due to the risk of delayed response time to receive threat notification from the current vendor in comparison to other vendors in the market. (3) Building an in-house threat intelligence application to fulfill the security threat intel requirements. This alternative was not selected because developing security platforms of this type is not in the core competences of the Company. The Company's resources do not have access to the wide range of threat data that other companies leverage to develop a threat intelligence application. In addition, the cost to maintain an in-house application of this type would not be economically practical. (4) Implementing a threat intelligence application that meets the Company's security threat intelligence requirements. This alternative was selected.

- The **Security/OT Field Modernization** project requires $129,249 in capital ($103,399 ROM Adjusted Capital) and $46,236 in O&M in the test year.
  - **Description:** This project will implement new infrastructure for accomplishing improved security in the field for OT assets.
  - **Problem Statement:** Gas and Electric technicians are using corporate laptops, to manage critical OT infrastructure which does not follow cyber security best practices for managing critical infrastructure. Vendors and contractors have access to the Company's critical infrastructure using non-Company laptops. Best practice is to use dedicated laptops to connect to critical infrastructure.
  - **Objectives:** The value of this project is deploying dedicated Company OT laptops and associated OT infrastructure that can move between OT locations only and providing a secure environment.
  - **Scope:** This project will procure and configure approximately 130 devices that will be used to manage critical OT infrastructure.
  - **Alternatives:** The Company reviewed several options to mitigate cyber security risks inherent with the use of standard corporate laptops managing critical infrastructure. The alternatives considered are: (1) Continue utilizing existing workflow of using Corporate domain laptops with software installed; (2) Bring in an outside vendor to design and implement a proposed infrastructure; (3) Complete disallowance of all local access to critical systems; (4) Extending the OT network to remote Company locations; (5) Deploy a dedicated Company OT laptop and OT

communications circuits, which includes cellular connectivity. The dedicated OT laptop and communications circuits presented the best way to secure the critical infrastructure by limiting internet and e-mail access. Vendors and contractors could also utilize these approved dedicated systems for managing infrastructure they help support at Company locations. Based on the analysis performed, the Company chose to deploy a dedicated OT laptop and communications circuits.

- The **TSA Critical Facility Structure** project requires $392,000 in capital and $14,267 in O&M in the test year.

  - **Description:** This project will implement enhanced security measures outlined by the Transportation Security Administration ("TSA") for critical facility assets in order to bring the locations up to enhanced status and avoid non-compliances. This project will increase the security and reliability of gas delivery to customers while also meeting federal requirements.

  - **Problem Statement:** Pipeline facilities that are deemed critical are required to apply enhanced security measures. Today, the Company currently has designated four locations as critical. However, based on the April 2021 update to the TSA Pipeline Security Guidelines, Section 5 (Critical Facility Criteria), a significant number of the Company's gas infrastructure that were not previously subject to evaluation will now fall into scope.

    As the Company continues to analyze the remainder of our gas assets, there is the potential for an additional 1,000 pipeline facilities (pipeline interconnections, metering and/or regulating stations, pump stations, compressor stations, operational control facilities, main line valve, tank farms and terminals, etc.) that may be deemed critical. The Company will be taking a phased implementation approach and will begin the process by implementing the enhanced security measures at the remainder of our compressor stations. Failure to update our sites will put the Company out of compliance with the updated guidelines.

  - **Objectives:** This project provides value to the Company by: (1) Implementing enhanced security measures outlined by the TSA for four critical assets; and (2) Increasing the security and reliability of gas delivery to customers while meeting federal requirements.

  - **Scope:** This project will implement the following enhanced security measures: (1) access controls; (2) access readers; (3) cameras; (4) video and audio programming; (5) fencing and barriers; (6) gates; (7) locks and key control; (8) fence intrusion; (9) subcontractor work of trenching poles, etc.; (10) facility lighting; (11) background investigations for personnel working at the site; (12) security equipment maintenance and testing; (13) security vulnerability assessments; (14) security communication plans;

(15) personnel training; and (16) security drills and exercises for the identified locations.

- **Alternatives:** Alternatives considered were: (1) To not implement the enhanced security measures outlined by the TSA for critical facility assets. This option was not chosen due to the risk of not complying with the TSA enhanced security measures. (2) To implement the enhanced security measures outlined by the TSA for critical facility assets. This alternative was chosen to avoid the risk of not complying with the TSA enhanced security measures, such as increased vulnerability of attacks, financial penalties, and operational disruptions.

**Q. Are the expenses and expenditures identified in this testimony reasonable and prudent?**

A. Yes. The O&M expenses and capital expenditures requested in this case will help the Company achieve the outcomes of the NGDP, continually improve the experience of customers' interactions with the Company, and maintain a reliable and secure technology base that is exposed to ever-increasing and serious cyber security threats over time. Technology is the backbone of Company operations and two-way customer communications. The Company has demonstrated the prudency of project expenditures and operational O&M requirements.

This testimony has provided detailed synopses of each project, a supplementary exhibit of the total project cost, hard savings, and cost/benefit analysis for each project in the test year, and a deep dive into benefits for several high priority projects. These are responses to concerns from previous rate cases and to provide additional insight to support recovery. The Company is seeking full recovery for these investments and operational expenses for technology solutions that keep its systems available, customers safe from growing cyber security threats, and that deliver on an improved gas future in the Company's NGDP.

**Q. Does this conclude your direct testimony?**

A. Yes.

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

| | | |
|---|---|---|
| In the matter of the application of<br>**CONSUMERS ENERGY COMPANY**<br>for authority to increase its rates for the<br>distribution of natural gas and for other relief. | )<br>)<br>)<br>)<br>) | Case No. U-21806 |

**REDACTED**

**REBUTTAL TESTIMONY**

**OF**

**STACY H. BAKER**

**ON BEHALF OF**

**CONSUMERS ENERGY COMPANY**

May 2025

**Q. Please state your name and business address.**

A. My name is Stacy H. Baker, and my business address is One Energy Plaza, Jackson, Michigan 49201.

**Q. Are you the same Stacy H. Baker who provided direct testimony in this proceeding on behalf of Consumers Energy Company ("Consumers Energy" or the "Company")?**

A. Yes, I am.

**Q. What is the purpose of your rebuttal testimony?**

A. The purpose of my rebuttal testimony is to respond to the testimony and exhibits submitted by the Michigan Public Service Commission ("MPSC" or the "Commission") Staff ("Staff"), Attorney General witness Sebastian Coppola, and Citizens Utility Board of Michigan ("CUB") witness Joshua W. Denzler in this case concerning the Information Technology ("IT") Department's Operations and Maintenance ("O&M") expenses and capital expenditures. Specifically, I will respond to:

- Staff witness Emma Zichi's proposed adjustments to IT Investments O&M and capital expenditures to correct errors discovered through audit and discovery;
- Staff witness Zichi's proposed adjustments to IT capital expenditures for Asset Refresh Program ("ARP")-Field Device Asset Management ("FDAM") and ARP-Workstation Asset Management ("WAM");
- Staff witness Zichi's proposed recommendations for the SAP S/4HANA Implementation project; and
- Staff witness Brittney Klocke's proposed adjustments to IT capital expenditures and IT Investments O&M expenses for the Product Family Enhancements-Customer-Capital and Click to Chat projects.

I will also respond to Attorney General witness Coppola's proposed adjustments to IT capital expenditures and IT Investments O&M expenses.

I will also respond to CUB witness Denzler's proposed adjustments to IT capital expenditures and IT Investments O&M expenses.

**Q. Are you sponsoring any exhibits with your rebuttal testimony?**

A. Yes.

| | |
|---|---|
| Exhibit A-109 (SHB-12) | Audit Response No. U21806-SA-CE-409; |
| Exhibit A-110 (SHB-13) | Discovery Response No. U21806-AG-CE-0615; |
| Exhibit A-111 (SHB-14) | Discovery Response No. U21806-AG-CE-0616-Revised; |
| Exhibit A-112 (SHB-15) | Audit Response No. U21806-SA-CE-176; |
| Exhibit A-113 (SHB-16) | Discovery Response Nos. U21806-CUB-CE-0121 through 0126 and U21806-AG-CE-0613, 0614, and 0847; and |
| Exhibit A-158 (SHB-17) | Discovery Response No. U21806-AG-CE-0852, Attachment 2. |

**Q. Were these exhibits prepared by you or under your supervision?**

A. Yes.

**MPSC STAFF**

**Q. What project is Staff witness Zichi proposing adjustments for in this case?**

A. On page 3, line 8, through page 4, line 3, of her direct testimony, Staff witness Zichi is proposing an adjustment for the Application Currency-Corporate-Capital project.

**Q. What amount is Staff witness Zichi proposing to adjust for the Application Currency-Corporate-Capital project?**

A. Based on Staff witness Zichi's Exhibit S-19.0, line 1, she is proposing an adjustment of $15,010 for the projected bridge period, $18,013 for the projected test year of capital expenditures, and $1,991 for the projected test year O&M for the Application Currency-Corporate-Capital project.

**Q. Do you agree with Staff witness Zichi's proposed adjustment to the Application Currency-Corporate-Capital project?**

A. Yes. The Company agrees with the basis of the proposed adjustment as explained in its response to Staff Discovery request U21806-ST-CE-0004 CONF (Exhibit S-19.2, page 2) that the 2025 and 2026 capital hardware/storage upgrade costs in each year were overstated by $15,010 for the bridge year, $18,013 for the projected test year, and $1,991 for the projected test year O&M. As a result, the capital expenditures for the projected bridge period and projected test year should be adjusted by $15,010 and $18,013, respectively, and $1,991 for test year O&M.

**Q. What additional project is Staff witness Zichi proposing adjustments for in this case?**

A. On page 4, lines 4 through 17, of her direct testimony, Staff witness Zichi is proposing an adjustment for the HR Support Pack and Business Software Inc Upgrade 2025 project.

**Q. What amount is Staff witness Zichi proposing to adjust for the HR Support Pack and Business Software Inc Upgrade 2025 project?**

A. Based on Staff witness Zichi's Exhibit S-19.0, line 2, she is proposing an adjustment of $20,119 for the projected test year O&M for the HR Support Pack and Business Software Inc Upgrade 2025 project.

**Q. Do you agree with Staff witness Zichi's proposed adjustment to the HR Support Pack and Business Software Inc Upgrade 2025 project?**

A. Yes. The Company agrees with the basis of the proposed adjustment as explained in its response to Staff Audit request U21806-SA-CE-049-Revised (Exhibit S-19.1, pages 3 and 4) that the O&M costs were overstated by $20,119 for the projected test year O&M. As a result, the expenses for the test year O&M should be adjusted by $20,119.

**Q. What additional project is Staff witness Zichi proposing adjustments for in this case?**

A. On page 4, line 18, through page 5, line 9, of her direct testimony, Staff witness Zichi is proposing an adjustment for the HR Support Pack and Business Software Inc Upgrade 2026 project.

**Q. What amount is Staff witness Zichi proposing to adjust for the HR Support Pack and Business Software Inc Upgrade 2026 project?**

A. Based on Staff witness Zichi's Exhibit S-19.0, line 3, she is proposing an adjustment of $40,454 for the projected test year O&M for the HR Support Pack and Business Software Inc Upgrade 2026 project.

**Q. Do you agree with Staff witness Zichi's proposed adjustment to the HR Support Pack and Business Software Inc Upgrade 2026 project?**

A. Yes. The Company agrees with the basis of the proposed adjustment as explained in its response to Staff Audit request U21806-SA-CE-049-Revised (Exhibit S-19.1, pages 3 and 4) that the O&M costs were overstated by $40,454 for the projected test year O&M. As a result, the expenses for the test year O&M should be adjusted by $40,454.

**Q. What additional project is Staff witness Zichi proposing adjustments for in this case?**

A. On page 5, line 16, through page 6, line 12, of her direct testimony, Staff witness Zichi is proposing an adjustment for the Application Currency-Electric & Gas Shared-Capital project.

**Q. What amount is Staff witness Zichi proposing to adjust for the Application Currency-Electric & Gas Shared-Capital project?**

A. Based on Staff witness Zichi's Exhibit S-19.0, line 9, she is proposing an adjustment of $19,146 for the projected bridge period, $22,975 for the projected test year of capital

expenditures, and $7,962 for the projected test year O&M for the Application Currency-Electric & Gas Shared-Capital project.

**Q. Do you agree with Staff witness Zichi's proposed adjustment to the Application Currency-Electric & Gas Shared-Capital project?**

A. Yes. The Company agrees with the basis of the proposed adjustment as explained in its response to Staff Audit request U21490-ST-CE-0003 CONF (Exhibit S-19.2, page 1) that the 2025 and 2026 capital hardware/storage upgrade costs in each year were overstated by $19,146 for the bridge year, $22,975 for the projected test year, and $7,962 for the projected test year O&M. As a result, the capital expenditures for the projected bridge period and projected test year should be adjusted by $19,146 and $22,975, respectively, and $7,962 for test year O&M.

**Q. What additional project is Staff witness Zichi proposing adjustments for in this case?**

A. On page 6, line 13, through page 7, line 1, of her direct testimony, Staff witness Zichi is proposing an adjustment for the Standard Work Plan project.

**Q. What amount is Staff witness Zichi proposing to adjust for the Standard Work Plan project?**

A. Based on Staff witness Zichi's Exhibit S-19.0, line 10, she is proposing an adjustment of $70,665 for the projected test year O&M for Standard Work Plan project.

**Q. Do you agree with Staff witness Zichi's proposed adjustment to the Standard Work Plan project?**

A. Yes. The Company agrees with the basis of the proposed adjustment as explained in its response to Staff Audit request U21806-SA-CE-075 (Exhibit S-19.1, page 5 and 6) that the O&M costs were overstated by $70,665 due to ongoing support costs being inadvertently

added for the projected test year O&M. As a result, the expenses for the test year O&M should be adjusted by $70,665.

**Q. What additional project is Staff witness Zichi proposing adjustments for in this case?**

A. On page 7, lines 2 through 19, of her direct testimony, Staff witness Zichi is proposing an adjustment for the Next Generation electronic Shift Operations Management System (eSOMS) Replacement project.

**Q. What amount is Staff witness Zichi proposing to adjust for the Next Generation electronic Shift Operations Management System (eSOMS) Replacement project?**

A. Based on Staff witness Zichi's Exhibit S-19.0, line 11, she is proposing an adjustment of $125,746 for the projected test year capital expenditures, and $8,243 for the projected test year O&M for the Next Generation electronic Shift Operations Management System (eSOMS) Replacement project.

**Q. Do you agree with Staff witness Zichi's proposed adjustment to the Next Generation electronic Shift Operations Management System (eSOMS) Replacement project?**

A. Yes. The Company agrees with the basis of the proposed adjustment as explained in its response to Staff Audit request U21806-SA-CE-076 (Exhibit S-19.1, page 7) that the projected gas allocation capital and O&M should be reduced by $125,746 for the projected test year, and $8,243 for the projected test year O&M. As a result, the capital expenditures for the projected test year should be adjusted by $125,746 and $8,243 for test year O&M.

**Q. What additional project is Staff witness Zichi proposing adjustments for in this case?**

A. On page 8, lines 4 through 17, of her direct testimony, Staff witness Zichi is proposing an adjustment for the ARP-Collaboration project.

**Q. What amount is Staff witness Zichi proposing to adjust for the ARP-Collaboration project?**

A. Based on Staff witness Zichi's Exhibit S-19.0, line 13, she is proposing an adjustment of $6,015 for the projected bridge period, and $7,219 for the projected test year capital expenditures for the ARP-Collaboration project.

**Q. Do you agree with Staff witness Zichi's proposed adjustment to the ARP-Collaboration project?**

A. Yes. The Company agrees with the basis of the proposed adjustment as explained in its response to Staff Audit request U21806-SA-CE-178 (Exhibit S-19.1, page 8 and 9) that the 2025 and 2026 capital hardware/storage upgrade costs in each year were overstated by $6,015 for the bridge year and $7,219 for the projected test year. As a result, the capital expenditures for the projected bridge period and projected test year should be adjusted by $6,015 and $7,219, respectively.

**Q. What additional project is Staff witness Zichi proposing adjustments for in this case?**

A. On page 13, lines 9 through 21, of her direct testimony, Staff witness Zichi is proposing an adjustment for the ARP-Physical Security project.

**Q. What amount is Staff witness Zichi proposing to adjust for the ARP-Physical Security project?**

A. Based on Staff witness Zichi's Exhibit S-19.0, line 17, she is proposing an adjustment of $72,640 for the projected bridge period, $108,960 for the projected test year of capital expenditures for the ARP-Physical Security project.

**Q. Do you agree with Staff witness Zichi's proposed adjustment to the ARP-Physical Security project?**

A. Yes. The Company agrees with the basis of the proposed adjustment as explained in its response to Staff Audit request U21806-SA-CE-018-Revised (Exhibit S-19.1, page 1 and 2) that the 2025 and 2026 capital hardware/storage upgrade costs in each year were overstated by $72,640 for the bridge year and $108,960 for the projected test year. As a result, the capital expenditures for the projected bridge period and projected test year should be adjusted by $72,640 and $108,960, respectively.

**Q. What adjustments is Staff witness Zichi proposing for the ARP-FDAM project in this case?**

A. On page 8, line 18, through page 9, line 4, of her direct testimony, Staff witness Zichi is proposing full disallowance of the new field device purchases of $831,046 for the 10-month bridge period ending 10/31/2025 and $999,543 for the projected test year ending 10/31/2026 as a part of the ARP-FDAM project.

**Q. What is Staff witness Zichi's rationale for proposing full disallowance of the new field device purchases for the ARP-FDAM project?**

A. On page 9, line 5, through page 10, line 19, of her direct testimony, Staff witness Zichi provides the rationale that the Company has not provided clear evidence to support the expenditures for new purchases for the ARP-FDAM project and there are conflicting rationales in the Company's testimony and audit responses regarding how the costs were projected.

**Q. Did the Company provide the method for projecting the new field device purchases costs and clarify in audit how the costs were projected?**

A. Yes. The Company provided in the audit response at Exhibit S-19.1, page 12 (U21806-SA-CE-325), that the Company projected the Total Company new purchases of $997,255 and $1 million for 2025 and 2026, which the basis was historical spend. The Company provided the historical actuals to validate the reasonableness of the projected 2025 and 2026 new purchase costs for ARP-FDAM, which historically had been included in ARP-WAM. Additionally, Exhibit S-19.1, page 12, references audit response Exhibit S-19.1, page 11 (U21806-SA-CE-288), that indicates that further investigation revealed that the Company did not use People and Culture hiring estimates to project new purchases for 2025 and 2026. Furthermore, Exhibit S-19.1, page 11, provides support that the four-year historical average for new purchases for 2020 – 2023 for ARP-FDAM and ARP-WAM exceeds what is being requested in this case for ARP-FDAM and ARP-WAM new purchases for 2025 and 2026.

**Q. What is the impact of co-workers not having a field device to perform work in service of customers?**

A. The absence of field devices for co-workers can significantly impact their ability to perform work effectively. Without field devices, co-workers face productivity losses due to the need to access information through less efficient means, such as using paper-based resources. This can lead to delays in work initiation and completion. The lack of access to electronic safety manuals and resources can increase safety risks. Workers may not have the most up-to-date safety information readily available, which is crucial for maintaining a safe working environment. Field devices facilitate better communication, especially

during emergencies or unexpected events. Without them, there is a risk of losing business continuity and effective communication, which can hinder timely responses to customer needs. Field devices provide access to online training and Company resources, which are essential for continuous learning and skill development. Without these devices, workers may miss out on training, leading to a gap in knowledge and skills. Sharing devices among employees can pose cybersecurity risks. Field devices help mitigate these risks by providing individual access to necessary resources, reducing the need for device sharing. Overall, the lack of field devices can lead to decreased efficiency, increased safety risks, and hindered communication, all of which negatively impact the service provided to customers.

**Q. If Staff witness Zichi's proposed disallowance for the ARP-FDAM project is nonetheless adopted, has the Company identified any necessary adjustments to the disallowance?**

A. Yes. The Company has identified necessary adjustments for the ARP-FDAM project. The projected gas allocation capital expenditures for this project are $261,198 for the 10-month bridge period ending 10/31/2025 and $314,156 for the projected test year ending 10/31/2026, as provided in Exhibit A-22 (SHB-7), page 4, column (h), lines 4 through 6, for the test year. The capital expenditure amounts that Staff witness Zichi references in Exhibit A-22 (SHB-7), page 4, columns e and g, in her direct testimony on page 9, line 2, are the Total Company amounts and not the gas allocation. Therefore, if the Commission were to disallow this project based on Staff witness Zichi's position, which it should not, the gas projected capital expenditure disallowance of $261,198 for the 10-month bridge

period ending 10/31/2025 and $314,156 for the projected test year ending 10/31/2026, would be the correct disallowance amount.

**Q. What adjustments is Staff witness Zichi proposing for the ARP-WAM project in this case?**

A. On page 10, line 20, through page 11, line 7, of her direct testimony, Staff witness Zichi is proposing full disallowance of the new workstation purchases of $831,077 for the 10-month bridge period ending 10/31/2025 and $997,292 for the projected test year ending 10/31/2026 as a part of the ARP-WAM project.

**Q. What is Staff witness Zichi's rationale for proposing full disallowance of the new workstation purchases for the ARP-WAM project?**

A. On page 11, line 8, through page 13, line 4, of her direct testimony Staff witness Zichi provides the rationale that the Company has not provided clear evidence to support the expenditures for new purchase for the ARP-WAM project and there are conflicting rationales in the Company's testimony and audit responses regarding how the costs were projected.

**Q. Did the Company provide the method for projecting the new workstation purchases costs and clarify in audit response how the costs were projected?**

A. Yes. The Company provided in audit response Exhibit S-19.1, page 11 (U21806-SA-CE-288), that the Company projected the Total Company new purchases of $1 million for 2025 and 2026, which the basis was historical spend. The Company provided historical actuals to validate the reasonableness of the projected 2025 and 2026 new purchase costs for ARP-WAM, which historically had been included in ARP-FDAM. Additionally, the Company indicated that further investigation revealed that the Company did not use People and

Culture hiring estimates to project new purchases for 2025 and 2026. Furthermore, Exhibit S-19.1, page 11, provides support that the four-year historical average for new purchases for 2020 – 2023 for ARP-WAM and ARP-FDAM exceeds what is being requested in this case for ARP-WAM and ARP-FDAM new purchases for 2025 and 2026.

**Q. What is the impact of co-workers not having a workstation to perform work in service of customers?**

A. The absence of a workstation for co-workers can significantly impact their ability to perform work effectively. Without access to a workstation, co-workers face productivity losses due to the need to access systems to perform their work. This can lead to delays in work initiation and completion. Additionally, the inability to access electronic processes and systems significantly impacts their ability to perform work effectively, such as performing essential diagnostics, monitoring, and planning of critical systems. Workers may not have the most up-to-date safety and compliance information readily available, which is crucial for maintaining a safe working environment and regulatory compliance. Workstations facilitate better communication, especially during emergencies or unexpected events. Without them, there is a risk of losing business continuity and effective communication, which can hinder timely responses to customer needs. Workstations provide access to online training and Company resources, which are essential for continuous learning and skill development. Without these workstations, workers may miss out on training, leading to a gap in knowledge and skills. Sharing devices among employees can pose cybersecurity risks. Workstations help mitigate these risks by providing individual access to necessary resources, reducing the need for device sharing. Overall, the lack of workstations can lead to decreased efficiency, increased safety and

compliance risks, and hindered communication, all of which negatively impacts the service provided to customers.

**Q. If Staff witness Zichi's proposed disallowance for the ARP-WAM project is nonetheless adopted, has the Company identified any necessary adjustments to the disallowance?**

A. Yes. The Company has identified necessary adjustments for the ARP-WAM project. The projected gas allocation capital expenditures for this project are $261,197 for the 10-month bridge period ending 10/31/2025 and $314,300 for the projected test year ending 10/31/2026, as provided in Exhibit A-22 (SHB-7), page 12, column (h), lines 8 through 18, for the test year. The capital expenditure amounts that Staff witness Zichi used in the adjustment calculations are the Total Company amounts and not the gas allocation. Therefore, if the Commission were to disallow this project based on Staff witness Zichi's position, which it should not, the gas projected capital expenditure disallowance of $261,197 for the 10-month bridge period ending 10/31/2025 and $314,300 for the projected test year ending 10/31/2026, would be the correct disallowance amount.

**Q. Did Staff provide any recommendations regarding the SAP S/4HANA Implementation project?**

A. Yes. On page 14, lines 6 through 18, of her direct testimony, Staff witness Zichi proposed two recommendations regarding the SAP S/4HANA Implementation project.

First, Staff is recommending the Commission direct the Company to meet with Staff quarterly to provide progress of the SAP S/4HANA Implementation project, including any advancements and/or setbacks in project implementation, budget adherence,

changes to project scope, timeline, expenses, and any problems the Company has experienced or anticipates experiencing with any operations or customer interactions.

Second, Staff is recommending the Company include in future rate case filings until implementation is complete, any over and under recovery of each projected expense for the project compared to the 80% base (Rough Order of Magnitude ("ROM") Adjusted Amount).

**Q. Does the Company agree with Staff witness Zichi's recommendations regarding the SAP S/4HANA Implementation project?**

A. Yes. The Company agrees with Staff witness Zichi's recommendations regarding the SAP S/4HANA Implementation project as described above.

**Q. What projects is Staff witness Klocke proposing adjustments for in this case?**

A. As stated on page 5, lines 15 through 19, of her direct testimony, Staff witness Klocke is proposing adjustments for the Click to Chat project and Product Family Enhancements-Customer-Capital projects that includes Web Chat AI, Self-Service Mobile Application, and Low Moderate Income ("LMI") Customer Support enhancements. Company witness Jessica R. Byrom and I will address each proposed adjustment.

**Q. What amount is Staff witness Klocke proposing to disallow for the Click to Chat project?**

A. On page 5, line 30, through page 6, line 2, of her direct testimony, Staff witness Klocke is proposing full disallowance of the capital expenditures requested in this case for the Click to Chat project of $48,641, with $45,683 in the historical year ended December 31, 2023 and $2,958 in the bridge year ended December 31, 2024.

**Q. Do you agree with Staff witness Klocke's proposal of full disallowance of the Click to Chat project?**

A. No. The Company does not agree with Staff witness Klocke's proposal of full disallowance of the Click to Chat project. First, this project was included in the gas rate Case No. U-21308 and in electric rate Case No. U-21389, and no parties recommended disallowance of the project in those cases. Thus, the projections approved in those cases included approval of Click to Chat project costs. In the Commission's March 21, 2025 Order in Case No. U-21585, pages 183 through 186, the Commission approved the Click to Chat project 2023 historical year costs on the basis that although the Click to Chat function does not save money, it contributes to the provision of utility service. This same rationale should apply to the bridge period costs. Company witness Byrom's rebuttal testimony further addresses this project's value.

**Q. What amount is Staff witness Klocke proposing to disallow for the Product Family Enhancements-Customer-Capital project related to the Web Chat AI, Customer Self-Service Mobile Application, and LMI Customer Support enhancements?**

A. On page 8, lines 6 through 13, of her direct testimony, Staff witness Klocke is proposing full disallowance of the capital expenditures requested in this case for the Web Chat AI, Customer Self-Service Mobile Application, and LMI Customer Support enhancements that are part of Product Family Enhancements-Customer-Capital project of $1,905,494 ($61,562 for 2023, $274,116 for 2024, $699,355 10 months ending 10/31/2025, and $870,461 for the projected test year) in capital expenditures and $21,439 IT Investments O&M expense for the projected test year.

| Enhancements | Capital | | | | O&M |
|---|---|---|---|---|---|
| | Historical 12 Mos Ended 12/31/2023 | 12 Mos Ending 12/31/2024 | 10 Mos Ending 10/31/2025 | Projected Test Year 12 Mos Ending 10/31/2026 | Projected Test Year |
| Web Chat AI | $0 | $0 | $0 | $180,565 | $14,929 |
| Customer Self-Service Mobile Application | $61,562 | $274,116 | $498,727 | $649,770 | $6,510 |
| LMI Customer Support | $0 | $0 | $200,628 | $40,126 | $0 |

**Q. What adjustment is Staff witness Klocke proposing for the Web Chat AI enhancements that is part of the Product Family Enhancements-Customer-Capital project?**

A. On page 8, lines 14 through 20, of her direct testimony, Staff witness Klocke is proposing an adjustment of $180,565 in capital expenditures and $14,929 in IT Investments O&M expense for the projected test year for the Web Chat AI enhancements that is part of the Product Family Enhancements-Customer-Capital project.

**Q. Do you agree with Staff witness Klocke's proposal of full disallowance of the Web Chat AI enhancements that is part of the Product Family Enhancements-Customer-Capital project?**

A. No. The Company does not agree with Staff witness Klocke's proposal of full disallowance of the Web Chat AI enhancements that is part of the Product Family Enhancements-Customer-Capital project. Company witness Byrom's rebuttal testimony further addresses this project's value.

**Q. What adjustment is Staff witness Klocke proposing for the Customer Self-Service Mobile Application enhancements that is part of the Product Family Enhancements-Customer-Capital project?**

A. On page 11, lines 6 through 18, of her direct testimony, Staff witness Klocke is proposing an adjustment of $61,562 for historical year 2023, $274,116 for 2024, $498,727 for the 10 months ending 10/31/2025 ($598,472/12 *10), and $649,770 ($598,472/12*2 + $550,025) for the projected test year in capital expenditures and $14,929 in IT Investments O&M expense for the projected test year for the Customer Self-Service Mobile Application enhancements that are part of the Product Family Enhancements-Customer-Capital project.

**Q. Do you agree with Staff witness Klocke's proposal of full disallowance of the Customer Self-Service Mobile Application enhancements that is part of the Product Family Enhancements-Customer-Capital project?**

A. No. The Company does not agree with Staff witness Klocke's proposal of full disallowance of the Customer Self-Service Mobile Application enhancements that are part of the Product Family Enhancements-Customer-Capital project. Company witness Byrom's rebuttal testimony further addresses this project's value.

**Q. What adjustment is Staff witness Klocke proposing for the LMI enhancements that are part of the Product Family Enhancements-Customer-Capital project?**

A. On page 14, lines 2 through 5, of her direct testimony, Staff witness Klocke is proposing an adjustment of $200,628 for the 10 months ending 10/31/2025, and $40,126 for the projected test year in capital expenditures for the projected test year for the LMI Customer Support enhancements that are part of the Product Family Enhancements-Customer-Capital project.

**Q. Do you agree with Staff witness Klocke's proposal of full disallowance of the LMI enhancements that is part of the Product Family Enhancements-Customer-Capital project?**

A. No. The Company does not agree with Staff witness Klocke's proposal of full disallowance of the LMI enhancements that are part of the Product Family Enhancements-Customer-Capital project. Company witness Byrom's rebuttal testimony further addresses this project's value.

**Q. What is the current status of the Company's website redesign project Staff witness Klocke discusses in her direct testimony related to Web Chat AI, Customer Self-Service Mobile Application, and LMI Customer Support enhancements that are part of Product Family Enhancements-Customer-Capital project?**

A. As discussed in Staff Audit Response U21806-SA-CE-409 (Exhibit A-109 (SHB-12), the Company has put the website redesign on hold due to extended support of the current on-premises Sitecore web content management system and the Company's SAP S/4HANA planned implementation.

The previous timing for the website redesign was developed with the expectation that the Company would need to migrate to the cloud/Software-as-a-Service ("SaaS") version of the Sitecore system based on Sitecore's published product support lifecycle at that time. This would have been a major reason to initiate the website redesign. Since then, Sitecore has extended mainstream support for the on-premises version 10.4 to December 31, 2027, giving the Company more flexibility in its migration schedule.

In addition, the Company's implementation of the SAP S/4HANA system will be a major undertaking, which will significantly impact the design of integration between the

Company's website and SAP. The Company plans to complete the S/4HANA implementation before starting the website redesign.

It is important to note that improvements to the Company's website design, content, navigation, accessibility, and features are not static or stopped until the website redesign project is undertaken. The Company is regularly prioritizing and executing updates to web pages, content, and flows based on customer needs and challenges. An example of this is for the LMI Customer Support Enhancement. On page 15 of her direct testimony regarding LMI, Staff witness Klocke says, "Staff strongly feels that the Company updating their website to make information such as this standard would be a much better use of money." In fact, much of the investment in this enhancement is being achieved through updates to website design, content, features, and navigation, without the full re-architecture associated with the eventual website redesign project.

**Q. Do you agree that the Company's website redesign would negate the need to make investments in Customer Self-Service Mobile Application and Web Chat AI?**

A. No. The Website Redesign would not negate the need to make investments in the Customer Self-Service Mobile Application, Web Chat AI, or any other channels preferred by customers for specific needs, as discussed in Company witness Byrom's rebuttal testimony.

**Q. Are there any adjustments needed to the proposed adjustments for the Product Family Enhancements-Customer-Capital provided in Staff Exhibit S-19.0, line 6, for IT Investments O&M expense for the projected test year?**

A. Yes. Based on the amounts provided in Staff witness Klocke's direct testimony, on page 8, lines 17 through 18, for the Web Chat AI enhancement of $14,929 in IT Investments O&M expense for the projected test year and on page 11, lines 13 through 14, for the Self-Service

Mobile Application enhancements of $6,510 in IT Investments O&M expense for the projected test year, the total IT Investments O&M expense on Staff Exhibit S-19.0, line 6 should be $21,439.

**ATTORNEY GENERAL**

**Q. What projected capital expenditures and O&M expense adjustments is Attorney General witness Coppola proposing for the Tracking and Traceability project identified on pages 85 through 87 of his direct testimony?**

A. Attorney General witness Coppola is proposing on page 87, lines 4 through 6, of his direct testimony to remove $2,218,000 for the projected bridge period for the 10 months ending October 2025, and $5,295,000 for the projected test year of the Company's capital expenditures and $509,000 of the Company's projected test year Investments O&M expense for the Tracking and Traceability project.

**Q. What is the first argument Attorney General witness Coppola describes for adjustments to the Tracking and Traceability project?**

A. The first argument Attorney General witness Coppola describes on page 86 of his direct testimony for removing amounts for the Tracking and Traceability project, is his claim that, based on the Company's cost benefit analysis, it appears that the Company is not expecting any significant cost savings from the new system.

**Q. Does the Company agree that the Tracking and Traceability project must provide significant cost savings in order to be viable?**

A. No. The project is required to meet Pipeline and Hazardous Materials Safety Administration ("PHSMSA") proposed regulatory requirements (PHSMSA-2014-0098), also known as the Plastic Pipe rule, as described in Company witness Lincoln D.

Warriner's direct testimony on pages 76 and 77. Company witness Warriner's rebuttal testimony further addresses this project's value.

**Q. What is the second argument Attorney General witness Coppola describes for removing amounts for the Tracking and Traceability project?**

A. The second argument Attorney General witness Coppola describes on page 86, line 18, through page 87, line 3, of his direct testimony for removing amounts for the Tracking and Traceability project is that the project is currently in the Origination Phase or Investment Planning stage.

**Q. Does the Company agree the Tracking and Traceability project should be disallowed because it is in the Investment Planning phase?**

A. No. This project should not be disallowed on the basis that it is in the Investment Planning phase. Investment Planning is the phase a project remains in while it is waiting for funding and does not indicate that it is incomplete or lacking information. An IT business case was completed and approved for this project prior to consideration for inclusion in the Company rate case, following the Company's business case process. Even though the business case is complete and approved, projects remain in this Investment Planning Phase and are not released for further planning and implementation activities until funding is approved through rate case and budget disposition. Therefore, significant requirements are complete, and the project should be included and approved as the Company fully plans to spend the projected expenditures based on the project timeline in this case.

**Q. What projected capital expenditures adjustments is Attorney General witness Coppola proposing for the SAP S/4HANA Implementation project identified on page 90 of his direct testimony?**

A. Attorney General witness Coppola is proposing on page 90, lines 7 through 9, of his direct testimony proposed to remove [redacted] for the 10 months ending October 2025 and [redacted] for the projected test year of the Company's capital expenditures for the SAP S/4HANA Implementation project.

**Q. What is Attorney General witness Coppola proposing for SAP S/4HANA Implementation project O&M costs identified on page 90 of his direct testimony?**

A. Attorney General witness Coppola is proposing on page 90, lines 9 through 11, that the Commission reject the Company's proposal to defer [redacted] O&M costs into a regulatory asset.

**Q. What is the argument Attorney General witness Coppola describes for capital expenditures adjustments and rejecting the proposal for deferral of O&M costs to a regulatory asset for the SAP S/4HANA Implementation project?**

A. The first argument Attorney General witness Coppola describes on page 89, line 16, through page 90, line 4, of his direct testimony for removing capital amounts and rejecting deferral of O&M costs for the SAP S/4HANA Implementation project is his claim that the current Enterprise Resource Planning ("ERP") system still functions well and meets the operating needs, and that it appears that the option exists for the Company to continue to operate the system into 2030 and potentially past the date with system support by SAP.

**Q. Does the Company agree that the option exists to continue to operate the current system into 2030 and potentially past the date with system support by SAP?**

A. No. The project will take approximately three years to complete and extended support for the Company's current SAP version is only available until 2030, as discussed in my direct testimony, on page 108, lines 10 through 17. There is also an increased risk of cyberattacks if the SAP S/4HANA project is not executed, because SAP has stated that after maintenance ends, standard patches will no longer be available, as discussed on page 108, line 18, through page 109, line 10, of my direct testimony.

**Q. What is the second argument Attorney General witness Coppola describes for capital expenditure adjustments and rejecting the proposal for deferral of O&M costs to a regulatory asset for the SAP S/4HANA Implementation project?**

A. The second argument Attorney General witness Coppola describes on page 86, line 18, through page 87, line 3, of his direct testimony for removing capital amounts and rejecting deferral of O&M costs for the SAP S/4HANA Implementation project is his contention that the project is premature.

**Q. Does the Company agree the SAP S/4HANA Implementation project capital expenditures should be disallowed and proposal for deferral of O&M costs be rejected because it is premature and in the Investment Planning phase?**

A. No. This project's capital expenditures should not be disallowed and proposal for deferral of O&M costs rejected on the basis that it is in the Investment Planning phase. Investment Planning is the phase a project remains in while it is waiting for funding and does not indicate that it is premature or incomplete or lacking information. Although the Company plans to issue a request for proposal in May 2025 for implementation partners, the

Company leveraged a third party that specializes in preparing for S/4HANA upgrades to develop the cost estimates for the business case, as stated in my direct testimony on page 109, lines 11 through 15. The IT business case was completed and approved for this project prior to consideration for inclusion in the Company rate case, following the same strict business case process. Even though the business case is complete and approved, projects remain in this Investment Planning Phase and are not released for further planning and implementation activities until funding is approved through rate case and budget disposition. Therefore, significant requirements are complete, and the project should be included and approved as the Company fully plans to spend the projected expenditures based on the project timeline in this case.

**Q. What is the argument Attorney General witness Coppola describes for removing the O&M amounts for the SAP S/4HANA Implementation project?**

A. Similar to the capital expenditures, the argument Attorney General witness Coppola describes on page 180, lines 3 through 6, of his direct testimony for removing amounts for the SAP S/4HANA Implementation project is his contention that the project is premature.

**Q. Did Attorney General witness Coppola make any additional recommendations related to the SAP S/4HANA Implementation project?**

A. Yes. Attorney General witness Coppola, on page 180, lines 7 through 10, made two recommendations. First, that the Commission not approve a regulatory asset to record the deferred IT Investments O&M expense for this project. Second, that the Commission not approve a 15-year amortization for the cloud implementation costs. Refer to Company witness Heidi J. Myers' rebuttal testimony for further information on these requests.

**Q. Does the Company agree the SAP S/4HANA Implementation project should be disallowed because it is premature?**

A. No, for the same reasons discussed above.

**Q. What is Attorney General witness Coppola's proposed adjustment to IT Investments O&M expense related to cloud computing?**

A. On page 108, line 2 through 4, and page 180, line 12, through page 181, line 2, Attorney General witness Coppola indicates that the Company made an error in calculating the amortization expense for cloud computing fees and costs that have been deferred and that the difference of $5,478,000 should be removed from the expense forecasted by the Company for the projected test year.

**Q. Do you agree that the Company made an error in calculating the amortization expense for cloud computing fees?**

A. No. The Company did not make an error in calculating the amortization expense for cloud computing fees. In response to Discovery request No. U21806-AG-CE-0852, Attachment 2 (Exhibit A-158 (SHB-17)), the Company provided an updated Exhibit A-18 (SHB-2) excluding some non-cloud computing pre-payments and expenses that were included inadvertently in that exhibit. The update to Exhibit A-18 (SHB-2) did not result in an error in the calculation of the amortization expense for cloud computing fees and costs included in the case for either IT Investments O&M or IT Operations O&M. Attorney General witness Coppola's conclusion is inaccurate and unvalidated. The Company provides a detailed list of projects in Exhibit A-20 (SHB-5) that supports the IT Investments O&M amounts in Exhibit A-19 (SHB-3), and the detailed exhibit does not include any line items for the amortization expense for cloud computing fees and costs. In addition, the original

Exhibit A-18 (SHB-2) was not used to project the amortization expense in IT Operations O&M expense; therefore, an update to Exhibit A-18 (SHB-2) would not result in a change to IT Operations O&M expense either. The Commission should not approve the removal of $5,478,000 from IT Investments O&M expense.

**Q. What is Attorney General witness Coppola's proposal regarding reducing the Company's working capital for the deferred costs for the SAP S/4HANA Implementation project and Prepaid Cloud Computing?**

A. On page 106, line 5, through page 107, line 4, and page 107, lines 5 through 18, Attorney General witness Coppola is proposing to reduce the Company's working capital adjustment for the deferred costs for the SAP S/4HANA Implementation project by $1.7 million and the Prepaid Cloud Computing by $1.0 million.

**Q. Do you agree with Attorney General witness Coppola's proposed adjustment to working capital for the SAP S/4HANA Implementation project and Prepaid Cloud Computing costs?**

A. Yes. The Company agrees with the basis of the proposed adjustment as explained in its response to Attorney General Discovery request U21806-AG-CE-0628 CONF (Exhibit AG-37, page 1) that the SAP S/4HANA Cloud Implementation Costs were inadvertently provided as Total Company rather than the gas allocation. Also, the Company agrees with the basis of the proposed adjustment as explained in its response to Attorney General Discovery request U21806-AG-CE-0852 (Exhibit AG-38, page 4) that the cloud computing prepaid balances inadvertently included some non-cloud computing pre-payments and expense.

**Q. Do you agree with Attorney General witness Coppola's proposal, at page 91, of his direct testimony, to reduce capital expenditures for the 10 months ending October 2025 to $423,000, and for the projected test year to $519,000 for the ARP-OT Support Gas project?**

A. No. Attorney General witness Coppola is basing the projections on a three-year historical average plus an adjustment for forecasted inflation. This does not consider that the cost projected for each year for the ARP-OT Support Gas project is for specific hardware that requires replacement based on timing of when it was installed and risk if it were not replaced in the five-year refresh cycle. As described in the response to Discovery request U21806-AG-CE-0615 (Exhibit A-110 (SHB-13)), the increase in the projected test year costs are due to the need to refresh assets implemented as a part of the Pipeline Supervisory Control and Data Acquisition ("SCADA") project. Maintaining a reliable control system is critical for ensuring continuous and safe gas flow.

**Q. Do you agree with Attorney General witness Coppola's proposal, at page 92, of his direct testimony, to reduce capital expenditures for the projected test year by $747,000 for the ARP-Physical Security project?**

A. No. Attorney General witness Coppola's proposal would result in running critical hardware to failure based on broad generalizations that the Company already has security cameras, gate and lock systems, and other security equipment in place. This does not consider that the costs projected for each year for the ARP-Physical Security project are for specific hardware that requires replacement based on timing of when it was installed and risk if it were not replaced based on the refresh cycle. In addition, this argument does not consider that this critical hardware is required to avoid physical security vulnerabilities

and to comply with state, federal, and Federal Energy Regulatory Commission ("FERC") requirements, as discussed in my direct testimony on pages 62 and 63, as well as the response to Discovery request U21806-AG-CE-0616-Revised (Exhibit A-111 (SHB-14)).

**Q. Do you agree with Attorney General witness Coppola's proposal, at page 93 of his direct testimony, to reduce capital expenditures by $939,000 and O&M expense by $180,000 for the projected test year for the Forward Web Proxy Services project?**

A. No. Attorney General witness Coppola's argument is that the project is not necessary at this time and not a priority that should be undertaken for the projected test year. Mr. Coppola indicates that the Company has been working with the vendor and acknowledged service improvement with some lingering issues. This does not consider that the Company no longer uses some of the functionality of the current product and that additional controls to mitigate risk had to be put in place in order to reduce impact and improve stability, as indicated in response to Discovery request U21806-AG-CE-0630 (Exhibit AG-31).

**Q. Does the Company agree that the Forward Web Proxy Services project must provide significant cost savings in order to be viable?**

A. No. The project is critical to filtering out unwanted or harmful content from the internet, protecting the Company's systems from cyberattacks. The project is also critical as the Company continues to leverage more SaaS solutions to provide consistent access and communication, while protecting the Company from cyber threats to avoid disruption to business operations. Refer to my direct testimony, page 115, line 36, through page 116, line 42, for further project value.

**Q. Has the Company identified any necessary adjustments to Attorney General witness Coppola's proposed adjustments for the Forward Web Proxy Services project?**

A. Yes. The Company has identified necessary adjustments for the Forward Web Proxy Services project. The projected test year gas allocation O&M expense for this project is $149,967 as stated on page 115, line 37, of my direct testimony. Therefore, if the Commission were to disallow this project based on Attorney General witness Coppola's position, which it should not, the projected test year gas allocation O&M expense of $149,967 would be the correct disallowance amount.

**Q. What projected capital expenditures and O&M expense adjustments is Attorney General witness Coppola proposing for the OT Datacenter Migration project identified on pages 95 through 97 of his direct testimony?**

A. Attorney General witness Coppola is proposing on page 95, lines 10 through 11, of his direct testimony to remove $1,441,000 for the projected test year of the Company's capital expenditures and $716,000 of the Company's projected test year Investments O&M expense for the OT Datacenter Migration project.

**Q. What is the first argument Attorney General witness Coppola describes for adjustments to the OT Datacenter Migration project?**

A. The first argument Attorney General witness Coppola describes on page 95, lines 12 through 17, of his direct testimony for removing amounts for the OT Datacenter Migration project is his claim that it is not clear why the Company could not resolve the water infiltration risk and the aging climate equipment at a lower cost than $11 million.

**Q. Does the Company agree that the water infiltration risk and aging climate equipment are the only risks the Company is resolving with the OT Datacenter Migration project?**

A. No. The project is planned to remove the risk of systems critical to the control of gas pipelines and the electric grid so they are no longer in close proximity to a railway system and the main water pipe for the building as described in my direct testimony on pages 100 and 101.

**Q. What is the second argument Attorney General witness Coppola describes for removing amounts for the OT Datacenter Migration project?**

A. The second argument Attorney General witness Coppola describes on page 95, lines 15 through 17, and page 97, lines 8 through 11, of his direct testimony for removing amounts for the OT Datacenter Migration project is that the project is currently in the Investment Planning stage.

**Q. Does the Company agree the OT Datacenter Migration project should be disallowed because it is in the Investment Planning phase?**

A. No. This project should not be disallowed on the basis that it is in the Investment Planning phase. Investment Planning is the phase a project remains in while it is waiting for funding and does not indicate that it is incomplete or lacking information. An IT business case was completed and approved for this project prior to consideration for inclusion in the Company's rate case, following the same strict business case process. Even though the business case is complete and approved, projects remain in this Investment Planning Phase and are not released for further planning and implementation activities until funding is approved through rate case and budget disposition. Therefore, significant requirements are

complete, and the project should be included and approved in this rate case as the Company fully plans to spend the projected expenditures based on the project timeline in this case.

**Q. What projected capital expenditures and O&M expense adjustments is Attorney General witness Coppola proposing for the Physical Access Management and Alarm Response project identified on pages 95 through 97 of his direct testimony?**

A. Attorney General witness Coppola is proposing on page 96, lines 10 through 12, of his direct testimony to remove $678,000 for the projected test year of the Company's capital expenditures and $102,000 of the Company's projected test year Investments O&M expense for the Physical Access Management and Alarm Response project.

**Q. Does the Company agree that the Physical Access Management and Alarm Response project must provide significant cost savings in order to be viable?**

A. No. Failing to move to new technology carries a growing risk of system failure which could result in unauthorized physical access and/or impact the Company's ability to efficiently function. Refer to my direct testimony, page 117, line 1, through page 118, line 28, for further project value.

**Q. What is the second argument Attorney General witness Coppola describes for removing amounts for the Physical Access Management and Alarm Response project?**

A. The second argument Attorney General witness Coppola describes on page 95, lines 15 through 17, and page 97, lines 8 through 11, of his direct testimony for removing amounts for the Physical Access Management and Alarm Response project is that the project is currently in the Investment Planning stage.

**Q. Does the Company agree that the Physical Access Management and Alarm Response project should be disallowed because it is premature and in the Investment Planning phase?**

A. No. This project should not be disallowed on the basis that it is in the Investment Planning phase. Investment Planning is the phase a project remains in while it is waiting for funding and does not indicate that it is premature or incomplete or lacking information. An IT business case was completed and approved for this project prior to consideration for inclusion in the Company rate case, following the same strict business case process. Even though the business case is complete and approved, projects remain in this Investment Planning Phase and are not released for further planning and implementation activities until funding is approved through rate case and budget disposition. Therefore, significant requirements are complete, and the project should be included and approved in this rate case.

**Q. Does the Company oppose Attorney General witness Coppola's recommendation on page 97, line 14, through page 98, line 4, of his direct testimony, that the Commission disallow $5,668,000 in capital expenditures for 2024 based on actual information?**

A. The Company will not oppose the reduction of $5,668,000 in capital for 2024 based on actual capital expenditures.

**CITIZENS UTILITY BOARD**

**Q. What observations does CUB witness Denzler provide for the Gas SCADA Software Solution project?**

A. On page 8, line 6, through page 10, line 13, CUB witness Denzler discusses changes that were made to the planned project and costs, and argues that the issues in planning of this project are evidence of a deficient estimation and planning process.

**Q. How do you respond to CUB witness Denzler's observations related to estimation and planning for the Gas SCADA Software Solution project based on changes from the project's initial ROM estimate?**

A. As discussed on page 33, line 12, through page 34, line 8, of my direct testimony, the Company performs the preliminary project stage activities that are essential to ensure the Company makes prudent investments in technology that benefit customers. In addition, as discussed on page 45, line 10, through page 46, line 3, IT's investment forecasts evolve over time. Factors may arise during project execution that results in funding being lower or higher than initially estimated. In the PMBOK (Project Management Body of Knowledge), ROM estimates have cost estimate bounds of -25% to +75%; this means that a ROM estimated project could end up costing between 25% less to 75% more than the initial estimate.

**Q. What other concerns does CUB witness Denzler indicate for the Gas SCADA Software Solution project?**

A. On page 10, line 14, through page 11, line 18, CUB witness Denzler argues that the merits and necessity of the project are not sufficiently justified.

**Q. Do you agree with CUB witness Denzler's concerns regarding the merits of the Gas SCADA Software Solution project?**

A. No. First, the Company's concerns with the current system are not based primarily on "hypothetical" future risks. As discussed on page 50, lines 11 through 22, of my direct testimony, the original Gas SCADA system implemented in 2000 was based on the gas system requirements at that time. The current system has capability gaps and requires custom interim fixes and integrations which adds complexity and cost to the current solution. The Gas SCADA system is critical in controlling and monitoring the Company's gas system. While Mr. Denzler argues that there is limited evidence to suggest that the current system is defective, it would be expected that defects are limited for such a critical system. If the system is unstable or not functioning, it would impact the Company's ability to operate and monitor real-time system conditions, maintain safe operations, and comply with regulatory requirements.

Additionally, the Company provided detailed explanation of incremental costs in my direct testimony, on page 54, line 1, through page 55, line 11, and the responses to Discovery requests provided in Exhibit A-113 (SHB-16).

**Q. What amount does CUB witness Denzler recommend the Commission disallow for the Gas SCADA Software solution project?**

A. On page 12, lines 1 through 7, of his direct testimony, CUB witness Denzler recommends that the Commission hold the total allowed capital at $11,491,200 as previously approved in Case No. U-21490. This would be a disallowance of $6,524,840.

**Q. Do you agree with CUB witness Denzler's recommendation to the Commission to hold the total allowed capital at $11,491,200 as previously approved in Case No. U-21490?**

A. No. Not allowing recovery of the costs required to complete this project, as previously discussed, would have a significant impact on the Company's ability to operate and monitor real-time system conditions, maintain safe operations, and comply with regulatory requirements. It is also important to note that Attorney General witness Coppola's proposed disallowance of $5,558,000 related to 2024 actuals, which the Company is not opposing as previously discussed, already includes a reduction of $4,623,400 in 2024 Gas SCADA Software Solution costs from an originally projected $8,027,542 to an actual amount of $3,404,142.

**Q. What concerns does CUB witness Denzler have with the methodology the Company utilizes to apply a 20% reduction on its projects with ROM estimates?**

A. On page 12, line 15, through page 13, line 3, of CUB witness Denzler's direct testimony, he indicates a concern that the Company has routinely underspent its ROM estimates by much more than 20%.

**Q. How do you respond to CUB witness Denzler's concern?**

A. Business objectives and priorities and customer needs and expectations can evolve. This may require IT projects to be reprioritized and may require the Company to shift capital funding between projects, which could account for spending changes on ROM projects. Reducing capital expenditures for an incremental 20% could negatively impact other planned and approved projects.

**Q. What recommendation does CUB witness Denzler provide for the ROM projections?**

A. On page 13, lines 4 through 10, of CUB witness Denzler's direct testimony, he recommends the Commission disallow a total of 40% of the ROM projections for 2025 and 2026. This is an incremental 20% over the Company's 20% ROM Adjustment for projects identified with the ROM estimate type. He indicates this level results in an incremental disallowance of $8.21 million (20% of $41.04 million) in 2025 capital spend and an incremental disallowance of $11.59 million (20% of $57.46 million) in 2026 capital spend.

**Q. Do you agree with CUB witness Denzler's proposal to disallow an incremental 20% over the Company's 20% ROM Adjustment for the specified projects based on ROM estimate classification?**

A. No. An incremental 20% reduction in capital for the specified projects imposes a shortfall in the projected funding required to deliver the scope and expected outcomes of those projects. The Company's IT & Security projects plan and execute on a budget. These budgets are based on the analysis resulting from the ROM estimate. This shortfall in recovery may require the Company to shift capital funding between projects and could negatively impact other planned and approved projects.

**Q. If CUB witness Denzler's proposed disallowance for an incremental 20% over the Company's 20% ROM Adjustment for the specified projects based on ROM estimate classification is nonetheless adopted, has the Company identified any necessary adjustments to the disallowance?**

A. Yes. The Company has identified necessary adjustments for the proposed disallowance for an incremental 20% over the Company's 20% ROM Adjustment for the specified projects based on ROM estimate classification. Based on Exhibit A-20 (SHB-5), the

projected gas allocation capital expenditures for the 2025 spend year (column a) with a ROM estimate classification (column k) is $13,569,004 (column l) and the projected gas allocation capital expenditures for the 2026 spend year (column a) with a ROM estimate classification (column k) is $40,545,837 (column 1). Therefore, if the Commission were to disallow the 20% incremental amount over the Company's 20% ROM Adjustment for the specified projects with ROM estimate classification based on CUB witness Denzler's position, which it should not, the gas projected capital expenditure disallowance of $2,261,501 (20% of $13,569,004/12*10) for the 10-month bridge period ending 10/31/2025 and $7,209,940 (20% of $13,569,004/12*2 + 20% of $40,545,837/12*10) for the projected test year ending 10/31/2026, would be the correct disallowance amounts.

**Q. Explain CUB witness Denzler's argument related to the ARP-Collaboration project.**

A. On page 14, lines 1 through 19, of CUB witness Denzler's direct testimony, he states that Company Exhibit A-22 (SHB-7) outlines unit volumes and costs for actual purchases in 2023-2024 and projected purchases for 2025-2026, and shows increasing unit costs without sufficient explanation. Mr. Denzler recommends that that historic unit cost adjusted for productivity and inflation ("PAI") should be used to determine the projected unit costs for 2025-2026.

**Q. Do you agree with CUB witness Denzler's arguments related to the ARP-Collaboration project.**

A. No. The costs in the ARP-Collaboration project can vary based on the requirements for the specific location the collaboration equipment will be installed. For example, based on vendor quotes, replacing a Surface HUB with a Microsoft Teams Room in a conference room at our Jackson location requires $7,243 where replacing the same equipment in a

conference room at our Grand Rapids location requires $9,269, due to varying sizes of conference rooms that require different wiring, among other differences.

Additionally, CUB witness Denzler's analysis contains inaccuracies. For example, when he calculated the Company Historical Average Unit Cost for the Hub 85" replacements, he only used historical unit costs in Exhibit A-22 (SHB-7), line 34, column b, of $16,679. There are two more instances of 85" Hub purchases on Exhibit A-22 (SHB-7), lines 35 and 114, that contain the historical unit costs of $16,679 and $24,436. Thus, the average unit cost for these three purchases is $19,264, not $16,679. Similarly, he also calculated the Company Historical Average Unit Cost for Hub 50" replacements and PolyCom Refresh using only one historical unit cost, rather than averaging all the historical unit costs.

While Mr. Denzler calls into question the increase in ARP-Collaboration project costs by pointing out that there was no increase in projected Field Device unit costs, field devices tend to be more standard and do not have the complexity of significantly different requirements based on where the equipment will be installed.

Finally, the Company does not agree that projected unit costs should be based on historical costs plus inflation adjusted by PAI. Refer to Company witness Myers' rebuttal testimony.

**Q. What adjustment for the ARP-Collaboration project is CUB witness Denzler recommending?**

A. On page 14, lines 10 through 12 of his direct testimony, CUB witness Denzler is proposing adjustments of $57,599 in 2025 and $88,718 in 2026 for the ARP-Collaboration project.

**Q. Do you agree with the amounts that CUB witness Denzler is proposing adjustments in the ARP-Collaboration project?**

A. No. The Company does not agree with the proposed gas allocation adjustments of $57,599 for the projected year 2025 and $88,718 for the projected year 2026 for the reasons stated previously for the ARP-Collaboration project.

**Q. Are there any adjustments needed to CUB witness Denzler's proposed adjustments for the ARP-Collaboration project?**

A. Yes. The projected test year for the case is 11/1/2025 through 10/31/2026. Therefore, the Company is not requesting the full projected year 2026 amount as stated by CUB witness Denzler. Therefore, if the Commission were to agree with the proposed gas allocation adjustments of $57,599 for the projected year 2025 and $88,718 for the projected year 2026, which it should not, the gas allocation adjustment for the 10 months ending 10/31/2025 should be $47,999 and the projected test year should be $83,532. In addition, as discussed above in response to Staff witness Zichi, the Company has already agreed to the reduction of $6,015 for the bridge period (10 months ending 10/31/2025) and $7,219 for the projected test year for the ARP-Collaboration project.

**Q. Explain CUB witness Denzler's arguments related to the ARP-Local Area Network ("LAN") project.**

A. On page 14, line 20, through page 15, line 5, of CUB witness Denzler's direct testimony, he argues that a similar situation exists for ARP-LAN as ARP-Collaboration in that in 2023 and 2024, the Company replaced 1,091 LAN switches at a cost of $2,793,094, which is an average unit cost of $2,560 per switch. However, for 2025 and 2026, the Company projected a unit cost of over $5,000 per switch. He argues that the increase in projected

costs lacks sufficient explanation, and that historic unit cost adjusted for PAI should be used to determine the projected unit costs for 2025-2026.

**Q. Do you agree with CUB witness Denzler's arguments related to the ARP-LAN project?**

A. No. The Company does not agree with CUB witness Denzler's arguments related to the ARP-LAN project. The type of LAN switch that requires replacement determines the unit cost, and the Company's cost projections were based on these specific requirements. For example, a Juniper EX4100 switch has a unit cost of $8,132, where a Juniper EX4400 has a unit cost of $20,512. To simply take the total historical costs and divide them by the total number of historical switches is not a sufficient methodology for projecting these types of costs. As provided in response to Staff Audit request No. U21806-SA-CE-176 (Exhibit A-112 (SHB-15)), the material naming convention used (e.g., LAN Switch A, LAN Switch B, etc.) is solely to differentiate each model within a given calendar year. The actual models associated with these designations may change from year to year, resulting in variations in unit pricing.

The Company also does not agree that projected unit costs should be based on historical costs plus inflation adjusted by PAI. Refer to Company witness Myers' rebuttal testimony.

**Q. What adjustment is CUB witness Denzler proposing for the ARP-LAN project?**

A. On page 15, lines 3 through 5, of his direct testimony, CUB witness Denzler is proposing adjustments of $55,911 in 2025 and $86,881 in 2026 for the ARP-LAN project.

**Q. Do you agree with the amounts that CUB witness Denzler is proposing adjustments for the ARP-LAN project?**

A. No. The Company does not agree with the proposed gas allocation adjustments of $55,911 for the projected year 2025 and $86,881 for the projected year 2026 for the reasons stated previously for the ARP-LAN project.

**Q. Are there any adjustments needed to CUB witness Denzler's proposed adjustments for the ARP-LAN project?**

A. Yes. The projected test year for the case is 11/1/2025 through 10/31/2026; therefore, the Company is not requesting the full projected year 2026 amount as stated by CUB witness Denzler. Therefore, if the Commission were to agree with the proposed gas allocation adjustments of $55,911 for the projected year 2025 and $86,881 for the projected year 2026, which it should not, the gas allocation adjustment for the 10 months ending 10/31/2025 should be $46,593 and the projected test year should be $81,719.

**Q. Explain CUB witness Denzler's overall recommendation for the Asset Refresh Programs.**

A. On page 15, lines 6 through 14, of his direct testimony, CUB witness Denzler argues that the Company overestimated costs for the ARP-Collaboration devices and ARP-LAN switches, which he argues raises concerns about the Company's methods for estimating costs of other devices. Mr. Denzler recommends that the Commission treat the Asset Refresh program estimates as Class III AACE estimates and disallow 20% of the remaining ARP spend.

**Q. Do you agree with CUB witness Denzler's overall recommendation for the Asset Refresh Programs?**

A. No. The Company does not agree with CUB witness Denzler's overall recommendation to disallow 20% of the remaining ARP projected expenditures. On page 56, line 10, through page 57, line 12, of my direct testimony, I explain that the Company refreshes hardware based on industry standards recommended refresh cycles to reduce security risk, avoid costs, avoid customer frustration, avoid lost productivity, and ensure continued vendor support. The Company also provides detailed projected actual capital expenditures for each ARP in Exhibit A-22 (SHB-7) and on pages 58 through 75 of my direct testimony. I provided detailed project summaries including refresh cycles, which is the basis for which annual costs are projected and detailed variance explanations for several of the ARPs. The unit costs for ARPs are typically based on either actual historical costs, quotes, or current agreements with vendors. In addition, the basis for CUB witness Denzler's recommendation to disallow 20% of the remaining ARPs, namely, that the Company "overestimated" costs for the ARP-Collaboration devices and ARP-LAN switches is incorrect as previously discussed.

**Q. What adjustment is CUB witness Denzler proposing for the remaining ARPs?**

A. On page 15, lines 12 through 14, of his direct testimony, CUB witness Denzler is proposing adjustments of $1,413,753 in 2025 and $1,579,067 in 2026 for the remaining ARPs.

**Q. Do you agree with these adjustments for the remaining ARPs?**

A. No. The Company does not agree with the proposed gas allocation adjustments of $1,413,753 for the projected year 2025 and $1,579,067 for the projected year 2026 for the

reasons stated previously for the ARP-Collaboration project, ARP-LAN project, and remaining ARPs.

**Q. Are there any adjustments needed to CUB witness Denzler's proposed adjustments for the remaining ARPs?**

A. Yes. The projected test year for the case is 11/1/2025 through 10/31/2026; therefore, the Company is not requesting the full projected year 2026 amount as stated by CUB witness Denzler. Therefore, if the Commission were to agree with the proposed gas allocation adjustments of $1,413,753 for the projected year 2025 and $1,579,067 for the projected year 2026, which it should not, the gas allocation adjustment for the 10 months ending 10/31/2025 should be $1,178,128 and the projected test year should be $1,551,515.

**Q. Explain CUB witness Denzler's arguments regarding the Asset Accounting Tax Upgrade project.**

A. On page 16, lines 1 through 12, of his direct testimony, CUB witness Denzler argues that the Company did not evaluate other software options and recommends that the Commission disallow the requested $126,165 in O&M for this project in the test year. If the Commission does not disallow the entire project, Mr. Denzler recommends the Commission treat this estimate as a Class III AACE estimate and disallow 20% of the projected test year O&M costs, or $25,233.

**Q. Do you agree with CUB witness Denzler's arguments regarding the Asset Accounting Tax Upgrade project?**

A. No. The Company does not agree with CUB witness Denzler's arguments regarding the Asset Accounting Tax Upgrade project. On page 76, lines 27 through 28, of my direct testimony, I explain that the Company plans as a part of the scope of the project to evaluate

the current vendor/project solution with market leaders to ensure that it is the best solution. Further on page 76, line 35, through page 77, line 1, I explain that moving to the SaaS version of the current software will reduce hardware and server support costs, and avoid database and server upgrades as a result of this project.

**Q. Do you agree with CUB witness Denzler's proposed adjustments for the Asset Accounting Tax Upgrade project?**

A. No. The Company does not agree with the proposed gas allocation adjustments of $126,165 in O&M for the projected test year, and does not agree with treating the Asset Accounting Tax Upgrade project like an AACE Class III estimate and disallow $25,233 (20% of $126,165). As stated in my direct testimony on page 76, lines 12 through 21, in 2025 the standard vendor support ends for the current system. This project is critical to ensuring compliance with regulated and financial accounting for fixed assets. In addition, the Company will not have the opportunity to recover these O&M expenses in subsequent years for this project. Unlike capital expenditures, which can be recovered in future cases, O&M expenses generally are not recoverable once the test year has passed.

**Q. Explain CUB witness Denzler's arguments regarding spending on IT Enhancements.**

A. On page 16, line 15, through page 17, line 12, of his direct testimony, CUB witness Denzler argues that the Company has not sufficiently demonstrated the necessity or benefit of these projects, and many larger-cost projects should be standalone projects and not included as Enhancements.

**Q. Do you agree with CUB witness Denzler's arguments regarding spending on IT Enhancements?**

A. No. The Company does not agree with CUB witness Denzler's arguments regarding spending on IT Enhancements. As stated in my direct testimony on page 92, lines 9 through 11, and page 93, lines 4 through 6, the Enhancement Worklist Detail Report (Exhibit A-25 (SHB-10)) provides a summary of the Enhancements queue of work requests, it is not intended to be a prioritized list of work. Prioritization of enhancements is ongoing and is completed by cross-functional teams based on the most critical needs. The Company considers enhancements to be up to $500,000 and it could be more if the work is low complexity and low risk. The one item that was included for $2.1 million is Mobile App enhancements, which is broken down into several smaller enhancements.

The Company has demonstrated the necessity and benefit of the projects. As described in my direct testimony on page 95, lines 3 through 15, the Company uses two methods to ensure projected enhancements expenditures and expenses in the test year are reasonable and prudent: (1) three-year historical average and (2) total cumulative demand. For the three-year historical average method, the Company calculates the actual three-year historical average plus known incremental work and compares it to the projected Test Year enhancement expenditures to validate the Test Year projects are in line with historical spend and known incremental work. The second method, total cumulative demand, compares the Total Gas Allocation Cumulative Worklist amount to the projected Test Year enhancement expenditures and expenses to validate the projections are in line with the projected demand.

**Q. Did the Company provide further information and value for several of the incremental enhancements in this case?**

A. Yes. See Company witness Byrom's rebuttal testimony for further discussion of the value for the Web Chat AI, Customer Self-Service Mobile Application, and LMI enhancements as a part of the Product Family Enhancements-Customer-Capital project.

**Q. What adjustments for IT Enhancements is CUB witness Denzler proposing?**

A. On page 17, lines 17 through 20, of his direct testimony, CUB witness Denzler is proposing an adjustment of $2,651,057 in 2025 and $2,062,093 in 2026 for IT Enhancements.

**Q. Do you agree with CUB witness Denzler's proposed adjustments for IT Enhancements?**

A. No. The Company does not agree with the proposed gas allocation adjustments of $2,651,057 in 2025 and $2,062,093 in 2026 for IT Enhancements.

**Q. Are there any adjustments needed to CUB witness Denzler's proposed adjustments for IT Enhancements?**

A. Yes. The projected test year for the case is 11/1/2025 through 10/31/2026; therefore, the Company is not requesting the full projected year 2026 amount as stated by CUB witness Denzler. Therefore, if the Commission were to agree with the proposed gas allocation adjustments of $2,651,057 for the projected year 2025 and $2,062,093 for the projected year 2026, which it should not, the gas allocation adjustment for the 10 months ending 10/31/2025 should be $2,209,214 and the projected test year should be $2,160,254.

**Q. Does this conclude your rebuttal testimony?**

A. Yes.

(Direct and Rebuttal Testimony bound in in Confidential Record)

JUDGE VARCHETTI: And the same with -- were you done, Counsel, with Mr. Bleckman's testimony and exhibits?

MR. RUSZKIEWICZ: Yes, with Mr. Bleckman.

JUDGE VARCHETTI: Are there any objections to the admission of the direct and rebuttal testimony of Mr. Bleckman or any of the associated exhibits?

Hearing none, those are admitted as well.

MR. RUSZKIEWICZ: Thank you, Your Honor.

(Direct and Rebuttal Testimony bound in)

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

| | | |
|---|---|---|
| In the matter of the application of<br>**CONSUMERS ENERGY COMPANY**<br>for authority to increase its rates for the<br>distribution of natural gas and for other relief. | )<br>)<br>)<br>)<br>) | Case No. U-21806 |

**DIRECT TESTIMONY**

**OF**

**MARC R. BLECKMAN**

**ON BEHALF OF**

**CONSUMERS ENERGY COMPANY**

December 2024

**Q. Please state your name and business address.**

A. My name is Marc R. Bleckman, and my business address is One Energy Plaza, Jackson, Michigan 49201.

**Q. By whom are you employed and in what capacity?**

A. I am employed by Consumers Energy Company ("Consumers Energy" or the "Company") as the Executive Director of Financial Planning and Analysis.

**Q. What are your current responsibilities?**

A. My responsibilities include preparation of the monthly forecasts, annual budgets, and long-term financial plans for Consumers Energy and CMS Energy, the parent company of Consumers Energy. As a part of my role, I conduct financial analyses and studies required for making various strategic decisions such as equity issuance, sale of businesses, and new investments. I assist the Chief Financial Officer in preparing the presentations for Board of Directors meetings, quarterly earnings calls, investor meetings, and industry conferences. My responsibilities also include preparation of the Renewable Energy Plan ("RE Plan") forecast model, which is a responsibility I have continued to assume from a previously held position.

**Q. Please describe your educational background and describe any positions held prior to your current position.**

A. I received a Master of Business Administration Degree with a Finance concentration from the Katz Graduate School at the University of Pittsburgh in 2002. Upon receiving this degree in May 2002, I joined Ford Motor Company ("Ford") as a Financial Analyst. During my seven years of employment at Ford, I worked in various finance roles throughout the company, including Assembly Operations, Powertrain Operations, Ford

Motor Credit, and the General Auditor's Office. My responsibilities within these organizations included, but were not limited to, forecasting of and variance reporting on, all Income Statement and Balance Sheet line items, as well as business process auditing. In July 2009, I left Ford to join Consumers Energy as a Principal Financial Analyst in the Company's Risk, Strategy, and Financial Advisory Services group. My responsibilities in this role included, but were not limited to, supporting the financial analysis and forecasting of the Company's renewable energy development plans, as well as conducting the Company's Enterprise Risk Management Program. In September 2012, I took on the role of Manager of Earnings Analysis in the Company's Financial Planning and Analysis Group. I assumed my current position as the Executive Director of Financial Planning and Analysis in February 2016.

**Q. Have you previously testified before the Michigan Public Service Commission ("MPSC" or the "Commission")?**

A. Yes. I provided testimony in:

- Case No. U-16543, the Company's 2011 Application to Amend the RE Plan;
- Case No. U-16581, the Company's 2011 Application for biennial review of the RE Plan;
- Case No. U-17301, the Company's 2013 Application for biennial review of the RE Plan;
- Case No. U-17752, the Company's 2015 Application to Amend the RE Plan;
- Case No. U-17792, the Company's 2015 Application for biennial review of the RE Plan;
- Case No. U-18231, the Company's 2017 Application for biennial review of the RE Plan;
- Case No. U-20322, the Company's 2018 Gas Rate Case;
- Case No. U-20483, the Company's RE Plan reconciliation proceeding for 2018;

- Case No. U-20650, the Company's 2019 Gas Rate Case;
- Case No. U-20697, the Company's 2020 Electric Rate Case;
- Case No. U-20722, the Company's RE Plan reconciliation proceeding for 2019;
- Case No. U-20963, the Company's 2021 Electric Rate Case;
- Case No. U-20984, the Company's RE Plan amendment proceeding for 2021;
- Case No. U-21009, the Company's RE Plan reconciliation proceeding for 2020;
- Case No. U-21148, the Company's 2021 Gas Rate Case;
- Case No. U-21197, the Company's RE Plan reconciliation proceeding for 2021;
- Case No. U-21224, the Company's 2022 Electric Rate Case;
- Case No. U-21308, the Company's 2022 Gas Rate Case;
- Case No. U-21352, the Company's RE Plan reconciliation proceeding for 2022;
- Case No. U-21374, the Company's Application for approval of revised Voluntary Green Pricing programs and a RE Plan amendment;
- Case No. U-21389, the Company's 2023 Electric Rate Case;
- Case No. U-21490, the Company's 2023 Gas Rate Case;
- Case No. U-21549, the Company's RE Plan reconciliation proceeding for 2023;
- Case No. U-21585, the Company's 2024 Electric Rate Case; and
- Case No. U-21816, the Company's RE Plan amendment proceeding for 2024.

**Q. What is the purpose of your direct testimony?**

A. The purpose of my direct testimony is to present my recommendations regarding the capital structure and cost of capital which should be used in computing the overall rate of return for Consumers Energy.

**Q. How is your direct testimony organized?**

A. My direct testimony is organized as follows:

**I. SUMMARY OF RECOMMENDATIONS**

**II. CAPITAL STRUCTURE AND COST RATES**

**A. Development of Capital Structure**

**B. Development of Cost Rates**

**III. EXHIBITS FOR CERTAIN FILING REQUIREMENTS – CREDIT RATINGS AND RECENT UTILITY BOND ISSUANCES**

**IV. PROJECTED CASH BALANCE**

**V. SUMMARY AND CONCLUSIONS**

**Q. Are you sponsoring any exhibits?**

A. Yes. I am sponsoring the following exhibits:

| | | |
|---|---|---|
| Exhibit A-14 (MRB-1) | Schedule D-1 | Overall Rate of Return Summary; |
| Exhibit A-14 (MRB-2) | Schedule D-1a | Capital Structure Development; |
| Exhibit A-14 (MRB-3) | Schedule D-1b | Comparison of Development of Capital Structure; |
| Exhibit A-14 (MRB-4) | Schedule D-2 | Cost of Long-Term Debt; |
| Exhibit A-14 (MRB-5) | Schedule D-3 | Cost of Short-Term Debt; |
| Exhibit A-14 (MRB-6) | Schedule D-4 | Cost of Preferred Stock; |
| Exhibit A-14 (MRB-7) | Schedule D-6 | Short-Term Debt Utilization; |
| Exhibit A-30 (MRB-8) | | Current and Historical Credit Ratings; |
| Exhibit A-31 (MRB-9) | | Recent Utility Corporate Bond Issuances; |
| Exhibit A-32 (MRB-10) | | Peer Company Commission Authorized Equity Ratios; |
| Exhibit A-33 (MRB-11) | | State Regulatory Evaluations; |
| Exhibit A-34 (MRB-12) | | Wells Fargo December 8, 2023 Report – Figure of the Week: Approved Equity Ratios, 2005-2023; |

| | |
|---|---|
| Exhibit A-35 (MRB-13) | Cumulative Annual Interest Savings; |
| Exhibit A-36 (MRB-14) | S&P Global August 7, 2024 Report – RRA State Regulatory Evaluations – Energy; |
| Exhibit A-37 (MRB-15) | UBS May 10, 2023 Report; and |
| Exhibit A-38 (MRB-16) | S&P February 14, 2024 Report. |

**Q. Were these exhibits prepared by you or under your direction or supervision?**

A. Yes.

## I. SUMMARY OF RECOMMENDATIONS

**Q. What capital structure are you recommending be utilized in the overall rate of return calculation?**

A. I am recommending that the capital structure shown on page 1 of Exhibit A-14 (MRB-1), Schedule D-1, be used in this case. This represents the actual capital structure as of December 31, 2023, adjusted for the projected changes in debt, equity, deferred income taxes, and Investment Tax Credit ("ITC") through the end of the test year ending on October 31, 2026. The development of the capital structure on a ratemaking basis is shown in columns (b) through (d). The equity ratio as a percentage of permanent capital is 50.75%. The equity ratio as a percentage of total capital is 42.58%.

**Q. What Return on Equity ("ROE") are you assuming to determine the overall cost of capital for Consumers Energy?**

A. I am assuming an ROE for Consumers Energy of 10.25%. This ROE is recommended by Company witness Ann E. Bulkley and supported in further detail in her direct testimony.

**Q. What is the overall rate of return for Consumers Energy that you recommend be used in this case?**

A. I am recommending an overall rate of return of 6.22% on an after-tax basis. This overall rate of return is the result of combining the capital structure and cost rates shown on Exhibit A-14 (MRB-1), Schedule D-1, page 1. The cost of the components and the weighted cost are shown in columns (e) through (i). The overall rate of return that I am recommending is the weighted cost of the various components of the capital structure.

## II. CAPITAL STRUCTURE AND COST RATES

### A. Development of Capital Structure

**Q. What is capital structure?**

A. Capital structure refers to the amounts and mix of a company's financing components which make up the funds used for its operations and capital investment. For the Company, this includes long-term debt, common equity, preferred equity (or preferred stock), short-term debt, ITC, and deferred income taxes.

**Q. What is long-term debt and short-term debt?**

A. Long-term debt consists of loans that have a due date (or maturity) that is more than one year from the date of issuance. For the Company, long-term debt consists exclusively of First Mortgage Bonds. Short-term debt represents borrowings that are short-term in nature (less than one year), and includes borrowings under the Company's credit facilities, including commercial paper and intercompany borrowings. The Company aims to finance its long-term capital (such as plant and property) with long-term debt and equity, and to finance short-term capital requirements (such as seasonal working capital needs) with

short-term debt. This financing strategy is explained in more detail later in my direct testimony.

**Q. What is common equity and preferred equity?**

A. Equity is the net worth (assets minus liabilities) of a company. Common equity increases with net income (retained earnings) and with equity contributions from the Company's parent, CMS Energy. Common equity decreases when the Company makes dividend distributions to CMS Energy. Preferred equity is distinguished from common equity in that there is a fixed preferred dividend rate on preferred stock. Also, preferred equity has a higher ("preferred") claim to the Company's net assets in the event of insolvency.

**Q. Do taxes play a part in the capital structure?**

A. Yes. Deferred taxes and ITC represent reported book taxes that, due to special Internal Revenue Service deductions, measurements, or treatments, will not have to be paid until sometime in the future. This represents a temporary "zero cost" source of funding for the Company and is included as a component of the capital structure.

**Q. How did you develop the long-term debt, preferred stock, common equity, short-term debt, deferred income tax, and ITC balances in the capital structure?**

A. I started with the actual balances of long-term debt, preferred stock, common equity, short-term debt, deferred income taxes, and ITC as of December 31, 2023, as shown in Exhibit A-14 (MRB-2), Schedule D-1a, page 1, column (e). I then made the adjustments shown in column (f) to arrive at the average test year balance ending October 31, 2026, in column (g) that I am recommending be used in this case.

**Q. Please explain the common equity adjustment of $2.291 billion.**

A. I have projected that the 13-month common equity balance for the test year will be $2.291 billion higher than the December 31, 2023 balance. The common equity adjustment of $2.291 billion consists of two components. The first is an adjustment to reflect $466 million in projected retained earnings on a weighted average basis from January 2024 through October 2026. The second is an adjustment of $1.825 billion to reflect the projected equity infusions on a weighted average basis from January 2024 through October 2026.

**Q. What are retained earnings?**

A. Retained earnings are a company's net income from operations and other business activities retained by the company as additional equity capital. Retained earnings are, thus, a part of stockholders' equity.

**Q. Please explain the retained earnings adjustment of $466 million.**

A. Since I started with the December 31, 2023 balance for common equity, it was necessary to make an adjustment to reflect the increase in the common equity balance through retained earnings that will occur on a weighted average basis through October 31, 2026.

**Q. Please explain how you projected the change in Consumers Energy's retained earnings from January 2024 through December 2024.**

A. For the period of January 2024 through September 2024, I relied on actual changes in regulatory retained earnings. For the period of October 2024 through December 2024, I assumed the change in retained earnings would be equal to the actual change in retained earnings for the same months in 2023.

**Q. Please explain how you projected the change in Consumers Energy's retained earnings from January 2025 through the test period ending October 2026.**

A. Consumers Energy has a long-standing policy of using an 80% dividend payout ratio. I assumed Consumers Energy's retained earnings rate to be $14.417 million per month, or $173.0 million per year, from January 2025 through October 2026.

**Q. Please explain how you arrived at Consumers Energy's retained earnings rate of $173.0 million per year.**

A. Based on Consumers Energy's Securities and Exchange Commission Form 10-K for 2023, I determined that Consumers Energy's net income for the 12-month period ended December 31, 2023, was $865 million. I used this amount as a proxy for the future net income and assumed a dividend payout ratio of 80%. Using these assumptions, I calculated an annual retained earnings amount of $173.0 million [$865 x (1-0.80)]. Exhibit A-14 (MRB-2), Schedule D-1a, page 3, shows the projected monthly retained earnings balance and calculates the 13-month average for the period ending October 31, 2026.

**Q. What are equity infusions?**

A. Equity infusions are cash investments made by CMS Energy into Consumers Energy, thereby increasing the Company's common equity balance.

**Q. Why did you make a $1.825 billion adjustment for the new equity infusions in your recommended capital structure?**

A. This is the amount needed to hold a 50.75% equity ratio for the test period in this case. CMS Energy made an equity infusion of $300 million in November 2024 and plans to make equity infusions of $115 million by December 2024, $450 million by February 2025, $475 million by June 2025, $450 million by February 2026, and $450 million by June

2026. Accordingly, I reflected this in the equity balance for the test year for this case on a weighted average basis. The impact of these equity infusions on the cumulative balance is shown on Exhibit A-14 (MRB-2), Schedule D-1a, page 3. The 13-month average for the period ending October 31, 2026, is $1.825 billion. When the 13-month average for the equity infusions of $1.825 billion is combined with the 13-month average $466 million retained earnings adjustment, the increase to equity capital is the $2.291 billion shown on Exhibit A-14 (MRB-2), Schedule D-1a, page 1.

**Q. How is your testimony structured with regards to the proposed equity ratio?**

A. My testimony describing the key factors and providing evidence that supports the proposed equity ratio of 50.75% is organized as follows:

i. Peer Authorized Equity Ratios are Higher and Trending Up

ii. Equity Ratio / ROE Impact on Credit Quality

iii. Rating Agencies' Assessment of the Regulatory Environment

iv. Credit Challenges Facing Regulated Utilities

**i. Peer Authorized Equity Ratios are Higher and Trending Up**

**Q. How does the 50.75% equity ratio proposed in this case compare to other utilities?**

A. To compare the 50.75% equity ratio proposed in this case to other utilities, I researched all rate case decisions of peer companies from 2020 through September 2024 and determined the authorized or approved equity ratio for each. This is reflected on Exhibit A-32 (MRB-10). Peer companies for this analysis is defined as regulated subsidiaries of the Company's ROE proxy group in Case No. U-21490, and excludes final orders received by in-state proxy DTE Energy Company as well as the Company. The average equity ratio

for the peer group was 54.05%, 330 basis points higher than the 50.75% proposed for Consumers Energy in this case.

**Q. Are the equity ratios reflected in your sample based on reported financial data or Commission-authorized equity ratios in regulatory proceedings?**

A. The equity ratios were taken from Commission orders and public filings and represent actual regulatory equity ratios authorized or approved by different commissions across the country. It is clear from this analysis that, on average, regulatory commissions of the Company's peer group are granting equity ratios that are much higher than the 50.75% that is proposed by the Company in the current case.

**Q. Are the utilities included in Exhibit A-32 (MRB-10) companies at the parent holding company level or the regulated subsidiary level?**

A. The utilities included in Exhibit A-32 (MRB-10) are at the regulated subsidiary level. This is important because Consumers Energy is a regulated subsidiary; therefore, the comparison to the average commission-authorized equity ratios also needs to be at that same level in order for the analysis to be a valid comparable benchmark in this case.

**Q. Is it appropriate to use equity ratios at the parent holding company level in order to determine the average "peer group" equity ratio for the Company in this case?**

A. No. Companies at the parent holding company level should not be considered "peers" for purposes of determining the average equity ratio for the Company's peer group. This would be a misleading comparison since equity ratios at the parent holding company level may be distorted by other, non-regulated balance sheet items. In addition, an analysis of equity ratios at the parent holding company level may also be skewed since the source for this data is most likely Securities and Exchange Commission reported financial statements,

which are prepared under Generally Accepted Accounting Principles ("GAAP"). There are major differences in how components of the capital structure are classified on a ratemaking basis and on a financial basis which would further distort the equity ratios calculated at the parent holding company level.

**Q. Has the Commission addressed the fact that an analysis of equity ratios at the parent holding company level is not appropriate?**

A. Yes. In its Order in Case No. U-20963, the Commission stated that "regulatory and financial data should not be combined" with such an analysis. Further, the Commission deemed that such an analysis is invalid assuming one "could not verify that its data contained equity ratios set by a regulatory commission in a rate case." It is clear from the Commission's Order that actual commission authorized equity ratios at the regulated subsidiary level as presented in Exhibit A-32 (MRB-10) is the preferred data source for an analysis comparing relative equity ratios of peers.

**Q. How does the trend in the Company's authorized equity ratio compare to other utilities?**

A. Equity ratios for regulated utilities have increased over the last several years. This trend was highlighted in a December 2023 Wells Fargo report on approved equity ratios. See Exhibit A-34 (MRB-12). As described in the Company's testimony in previous rate cases, negative cash flow and credit metric impacts occurred when federal tax changes took effect in 2018. In subsequent years, utility commissions adopted higher equity ratios as one way to combat those impacts. The Wells Fargo report shows an increase in approved electric utility equity ratios of 130 basis points from 2019 to 2023. In contrast, the Company's authorized equity ratio has <u>decreased</u> 262 basis points from 2019 to present, weakening

credit quality and putting the Company's credit rating at risk. The Company has presented data showing that peer authorized equity ratios are significantly higher and are trending up. While this data indicates that a higher equity ratio is warranted, the Company is proposing an equity ratio of 50.75% in this case. This is the minimum amount that, taken together with an ROE of 10.25%, reflects the appropriate level that the Commission should adopt to help preserve Consumers Energy's current credit rating.

**ii. Equity Ratio / ROE Impact on Credit Quality**

**Q. How does the equity ratio approved in this case impact the Company's credit metrics and credit quality?**

A. A key financial metric used by rating agencies is the ratio of Funds From Operations ("FFO") to Debt ("FFO-to-Debt ratio"). The calculation of this financial metric includes, in part, both the equity ratio and the authorized ROE of the Company; thus, there needs to be a balance between the Company's equity ratio and ROE that will ensure that this key financial metric does not degrade and cause significant credit deterioration. An equity ratio of 50.75% and an ROE of 10.25%, as recommended by the Company in this case, results in an FFO-to-Debt ratio that is sufficient in striking this balance.

**Q. What is an FFO-to-Debt ratio?**

A. An FFO-to-Debt ratio is a financial metric that compares a company's cash flow from operating activities to a company's leverage, or debt outstanding. It can also be described as a type of payback ratio, reflecting the Company's ability to repay its outstanding debt with operating cash flow. A higher FFO-to-Debt ratio, one which reflects a higher level of cash flow from operating activities to offset or otherwise reduce the risk associated with the Company's ability to pay its debts, is viewed favorably and indicative of a lower financial risk and a resulting higher relative credit rating. A higher credit rating, in turn,

results in lower financing rates. This is comparable to a bank's credit evaluation for someone requesting a personal loan. After reviewing personal income and outstanding debt, banks generally offer lower financing rates to individuals who have more cash flow to repay debt, indicating a relatively higher credit quality.

**Q. Discuss the relationship between the Company's ROE, its equity ratio, and the Company's credit metrics.**

A. As discussed earlier in my testimony, ROE and equity ratio are two inputs in determining the Company's ratio of FFO to Debt, and FFO-to-Debt ratios are used by credit agencies to determine the Company's financial health. Consequently, it is important to recognize that the Company's ROE and equity ratio cannot be evaluated in isolation, but should, instead, be viewed as interconnected components that determine the Company's overall financial health. An ROE of 10.25%, when taken together with an equity ratio of 50.75% results in an FFO-to-Debt ratio that the Company believes is acceptable in the current case and is responsive to recent Commission orders. A lower authorized ROE would, therefore, necessitate a higher approved equity ratio to maintain the same level of financial health.

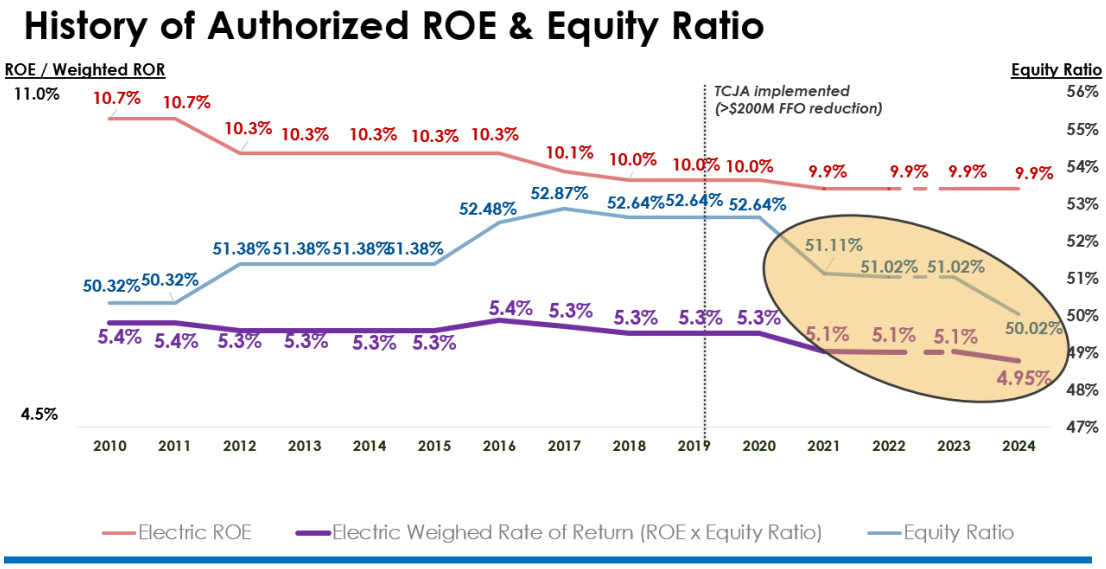
**Q. How can the combined cost of a Company's equity ratio and ROE components be properly evaluated?**

A. Multiplying the equity ratio by the ROE produces a weighted cost or "rate of return." This is shown on Exhibit A-14 (MRB-1), Schedule D-1, page 1. On line 6 of this exhibit, the equity ratio of 50.75% from column (c) is multiplied by the ROE of 10.25% from column (e) to produce a weighted cost of 5.20%, shown in column (f). This is the weighted cost of common equity, a component of the Company's overall rate of return. This rate of return is important to consider since it takes into account the equity ratio in combination

with the ROE. As discussed earlier in my testimony, the 50.75% equity ratio and 10.25% ROE is a combination that the Company believes is acceptable in the current case.

**Q. What has been the recent trend of the Company's weighted rate of return?**

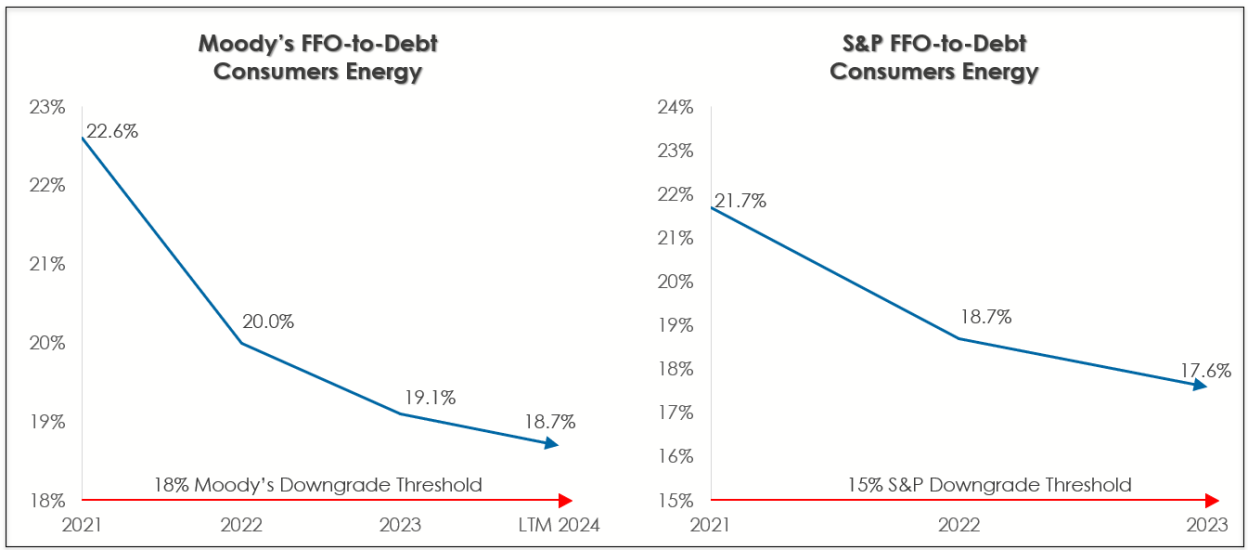
A. Following a long period of stability, recent rate cases have resulted in a sharp decline in rate of return. This is illustrated in the following chart which includes a history of electric authorized ROE, equity ratio, and resulting weighted rate of return.




**Q. What has been the trend of the Company's credit metrics over the last few years?**

A. The Company's FFO-to-Debt ratio as calculated by S&P has been trending down in recent years from 21.7% in 2021 to 17.6% in 2023, a decrease of 410 basis points and, for 2023, 40 basis points below the low end of S&P's expected range outlined in its 2023 report. In addition, the Company's FFO-to-Debt ratio as calculated by Moody's has also been trending down in recent years from 22.6% in 2021 to 19.1% in 2023, a decrease of 350 basis points. Moody's May 2024 credit report also shows a further decline to 18.7% for the 12 months ended March 2024. The Company's FFO-to-Debt ratio as calculated by Moody's is trending down and was well below the low end of Moody's expected range

(20-21%) for the Company for 2023 and through the first quarter of 2024. These credit metric results are shown in the following chart:




As explained earlier in my direct testimony, recent rate cases have resulted in a sharp decline in rate of return (ROE multiplied by equity ratio). A reduction in the Company's rate of return lowers the Company's cash flow and FFO-to-Debt ratio. The Company also needs to increase its long-term debt to achieve a lower equity ratio. This increase in debt also weakens the Company's FFO-to-Debt ratio. These negative credit metric impacts place the Company's credit quality and credit ratings at risk.

**Q. Should the potential for new tax legislation and the resulting deterioration of the Company's cash flow and credit metrics be considered in determining the appropriate ROE and equity ratio in this case?**

A. Yes. I am generally aware that Donald Trump, the winner of the 2024 presidential election, has indicated his intent to advance legislation that would lower the corporate income tax rate from 21% to 15%. Republican congressional control should help to facilitate the passage of this legislation. President Trump executed a similar tax policy initiative in his first term which led to the passage of the Tax Cuts and Jobs Act of 2017 ("TCJA"), which

reduced the corporate tax rate from 35% to 21%. As explained in my direct testimony in Case No. U-20322, the Company's 2018 gas rate case, the TCJA had direct and significant impacts on the Company's cash flow, resulting in a weakening of the Company's financial credit metrics. The Company's FFO was reduced by just over $200 million and, assuming approximately half of this reduction in cash is replaced with long-term debt, the Company's FFO-to-Debt ratio was reduced by 310 basis points. In addition, President Trump has indicated a desire to target portions of the Inflation Reduction Act of 2022 ("IRA") for repeal. Since aspects of the IRA allow for the Company to recognize cash proceeds from tax credit sales, this could also be detrimental to the Company's credit metrics. With these potential credit-harmful legislative actions looming during the test year of this case, it is especially important for the Commission to authorize an ROE and equity layer that will be supportive of the Company's credit quality. The authorized ROE and equity ratio are integral components of the Company's financial credit metrics and will be a key factor in combating the negative impacts of this potential tax legislation.

**Q. In addition to tax reform, are there other aspects of President Trump's agenda that could have material impacts on the Company's credit metrics during the test year of this case?**

A. Yes. From following the news during the election, I am aware that as a candidate, President Trump proposed a 60% tariff on goods from China as well as a 10% to 20% "universal" tariff on all imports, and also threatened a 25% tariff on Mexico, the United States' top trading partner. These tariffs, if enacted, could lead to disruption in the supply chain and a dramatic increase in the cost of materials, goods, and supplies. This, in turn could introduce significant regulatory lag in recovery of the Company's operations and

maintenance ("O&M") and capital spending which would have a detrimental impact on credit metrics and credit quality.

**Q. What are the customer benefits of the Company maintaining a higher credit rating?**

A. The Company provides a critical service that directly impacts customers' quality of life. The Company's ability to deliver long-term investments to the infrastructure that provide safe, reliable, and clean energy will depend on the financial strength of the Company, of which the Company's credit rating is a key indicator. As set forth in the testimony and exhibits of the Company's multiple capital witnesses, the Company is making significant capital investments to maintain and improve infrastructure to the benefit of customers. During this time, the Company will rely heavily on the capital markets to fund these investments. Generally, a higher credit rating results in lower financing rates. Therefore, it will be especially important for the Company to maintain strong credit ratings over this period. As shown in Exhibit A-35 (MRB-13), the Company has saved ratepayers $153 million annually as a result of improved credit ratings and lowered interest costs.

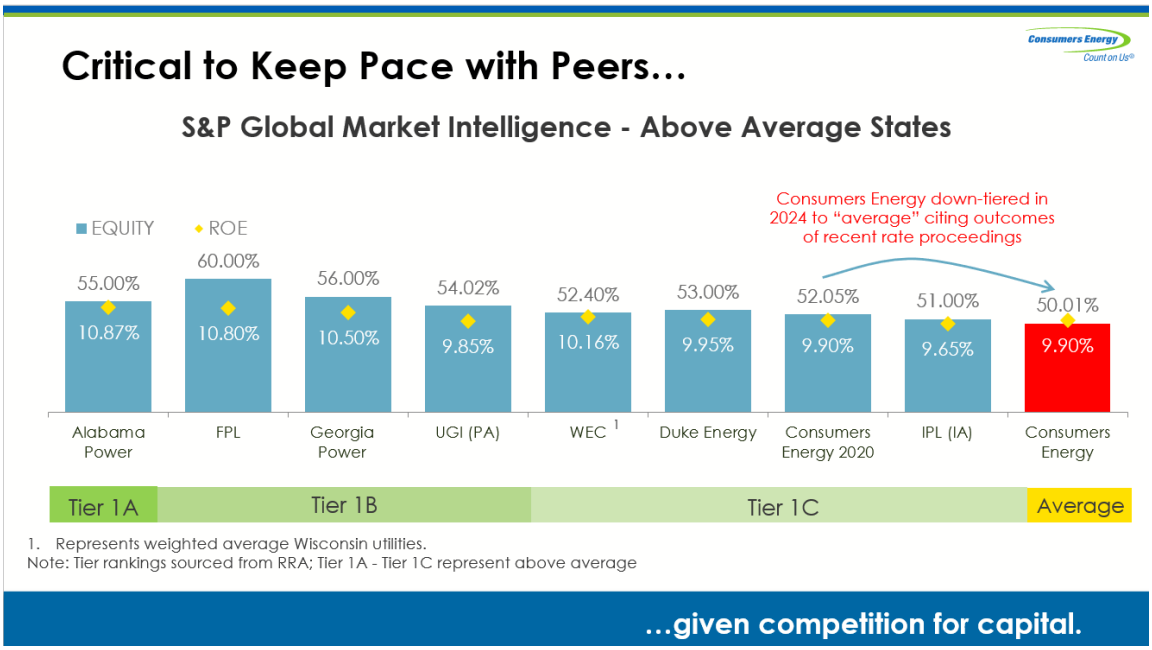
The common equity balance and equity ratio projected for the test year in this case also enable the Company to maintain strong credit ratings and better withstand any shocks in the financial markets. An example of this was in March 2023, when Silicon Valley Bank and Signature Bank collapsed, forcing the Federal government to step in and take over the banks. Silicon Valley Bank marked the biggest failure of a United States bank since the 2008 global financial crisis and led to significant market turmoil. Other large banks such as Credit Suisse and First Republic Bank also experienced significant financial pressure caused by the ensuing market panic. Strong credit ratings can help protect customers from spikes in interest rates which increase the cost of capital, and/or inaccessibility to the capital

markets which serve as a key source of financing for the Company's investments on behalf of customers. Strong credit ratings can also enable the Company to issue long-term debt ahead of upcoming maturities ("pre-fund") to take advantage of low interest rates and favorable issuance windows without jeopardizing the Company's financial ratios. When market conditions are favorable, refinancing higher interest rate debt at lower rates reduces the Company's overall cost of capital included in customer rates.

### iii. Rating Agencies' Assessment of the Regulatory Environment

**Q. How else does the equity ratio and ROE impact the Company's credit quality?**

A. One component of rating agencies' evaluation of credit quality involves an assessment of the Company's regulatory environment. If the Commission demonstrates a pattern of consistent, constructive rate orders, it contributes favorably to the Company's credit quality and credit rating. The authorized equity ratio and ROE are two important components in the rating agencies' assessment of the regulatory environment. Refer to Exhibit A-36 (MRB-14), S&P's State Regulatory Evaluations – Energy. In August 2024, S&P lowered its ranking of Michigan's regulatory environment from "Above Average" to "Average." This is reflected in the following chart:




In downgrading its state regulatory rating, S&P referenced recent rate case decisions in Michigan including authorized ROEs which "compare less favorably" to prevailing industry averages and a "tightening in the regulatory climate." In recent rate case filings, the Company has included this chart, noting that the recent decline in the Company's weighted rate of return has led to the risk that the Company will no longer be ranked as a utility in an above-average tier jurisdiction. S&P's August 2024 report confirms that this has risk has been realized.

**Q. Is there evidence that analysts have also started to recognize a decline in the state of the Company's regulatory environment?**

A. Yes. In updating its regulatory rankings for U.S. utilities in May 2023, UBS downgraded Michigan from Tier 1 to Tier 2. In describing the negative change, UBS specifically mentioned authorized ROEs ranking in the 3rd quintile as well as a lowering of their "subjective factor" for the Michigan regulatory jurisdiction, which is based on UBS's "knowledge of current commission actions." Refer to Exhibit A-106 (MRB-15). It is

apparent that rating agencies and analysts are taking note of the Company's regulatory outcomes and are viewing them unfavorably. A continuation or, even worse, a further degradation of the authorized equity ratio and ROE puts the Company at risk of dropping further in its regulatory environment rankings which could negatively impact the Company's credit quality and credit rating. Michigan's above average regulatory standing needs to be protected and bolstered rather than leveraged to justify further credit deterioration and over-leveraging of the Company.

**iv. Credit Challenges Facing Regulated Utilities**

**Q. Have rating agencies commented on the credit quality of regulated utilities as a whole?**

A. Yes. In a February 2024 report "Rising Risks: Outlook for North American Investor-Owned Regulated Utilities Weakens," S&P updated their outlook of the regulated utility industry to negative. S&P cites the high percentage of utilities with negative credit FFO-to-debt and the interrelationship between ROE, equity ratio, and credit metrics outlooks and expects that 2024 will likely be the fifth consecutive year that credit downgrades outpace upgrades. In its report (Exhibit A-107 (MRB-16)), S&P cites "headwinds to credit quality" including increased cash flow deficits that are funded to a higher extent with debt versus equity. S&P states that "for 2023, the industry's actual equity issuance was considerably below our expectations, resulting in a weakening of financial performance and credit quality. If this trend persists, credit quality will again likely experience pressure in 2024." S&P also notes utilities as having "strained financial cushion." Specifically, S&P states:

> About 35% of the industry is sustaining performance with minimal financial cushion, reflecting funds from operations (FFO) to debt that is less than 100 basis points (bps) above

> their downgrade threshold. The limited financial cushion affects a company's ability to absorb unexpected events beyond the base case for our ratings, increasing its susceptibility to a downgrade. [Exhibit A-107 (MRB-16), page 11.]

In addition, S&P cites the following credit headwinds impacting regulated utilities:

- Upcoming debt maturities amid higher interest rates, weakening financial performance;
- A narrowing spread between U.S. Treasuries and authorized ROE's which directly hinders the financial performance; and
- Elevated inflation rates resulting in higher costs that, given regulatory lag, could weaken financial performance.

S&P's assessment of the regulated utility industry was echoed by another credit rating agency, Fitch, in December 2023. In describing a "deteriorating outlook for North American utilities, power & gas in 2024," Fitch cited similar credit headwinds that are putting pressure on utilities' credit metrics. Specifically, Fitch concluded that "the sharp escalation in interest rates has significantly narrowed the headroom in FFO fixed-charge coverage for the sector."

As highlighted earlier in my testimony, there has been a sharp decline in the Company's authorized weighted rate of return following several years of consistent results. It is apparent from this S&P report that a supportive ROE and equity ratio is critical in maintaining a "financial cushion" to protect against downgrade in the event of unforeseen events like the market volatility and disruption that occurred during the onset of the COVID-19 pandemic in 2020 or the financial pressure caused by the dramatic increase in gas prices and interest rates in 2022 or the banking crisis of 2023. These events and rating agency comments highlight the importance for the Company to maintain strong financial metrics and to not manage toward the perceived low end of the credit metric bands. The

Company's ability to continue to provide customers with safe, reliable, and clean energy and make the necessary capital investments is directly tied to the Company's ability to maintain its financial strength.

**Q. Is an equity ratio of 50.75% and an ROE of 10.25% as proposed by the Company in this case the optimal outcome for the Company and its customers?**

A. Yes. This equity ratio and ROE combination is well-measured for both the Company and its customers, while still mindful of the Commission's Order in Case No. U-21389. This results in a weighted rate of return of 5.20% (50.75% x 10.25%), which is 25 basis points higher than the weighted rate of return of 4.95% (50.02% x 9.90%) approved in Case No. U-21389. This capital structure results in a reasonable impact on customer rates while bringing the Company more in-line with the authorized weighted rate of return experienced toward the beginning of the COVID-19 pandemic and prior to the most recent credit rating downgrade. The weighted rate of return as proposed in this case strengthens the Company's balance sheet and credit quality which will be critical in delivering the Reliability Roadmap investments while doing so in the midst of a sustained elevated interest rate environment.

**Q. Please explain the long-term debt adjustment of $2.248 billion.**

A. I have projected that the average debt balance for the test year ending October 31, 2026, will be $2.248 billion higher than the December 31, 2023 balance. This adjustment consists of the following components:

| **Long-Term Debt** (in millions) | | | Oct. 31, 2026 Test Year |
|---|---|---|---|
| Month | Issuance | Retirement | Impact |
| Jan. 2024 | $600 | $0 | $600 |
| Aug. 2024 | $700 | $0 | $700 |
| Sep. 2024 | $0 | ($250) | ($250) |
| Dec. 2024 | $0 | ($52) | ($52) |
| May 2025 | $475 | $0 | $475 |
| Aug. 2025 | $500 | $0 | $500 |
| May 2026 | $525 | ($115) | $189 |
| Aug. 2026 | $425 | $0 | $98 |
| Subtotal | | | $2,260 |
| Changes in Unamortized Fees | | | (12) |
| Total | | | **$2,248** |

The development of the 13-month average long-term debt balance is shown on Exhibit A-14 (MRB-2), Schedule D-1a, page 2.

**Q. Please describe the planned debt issuances in May 2025, August 2025, May 2026, and August 2026.**

A. Each of these planned debt issuances will be used for general corporate purposes of the Company including financing capital expenditures. The debt planned to be issued in May 2026 will also be used for the retirement of the Company's $115 million 5.24% bonds which mature in May 2026. These planned debt issuances have been determined based on

the Company's financing plans after evaluating cash and liquidity requirements for the Company.

**Q. What long-term debt was included in developing the 13-month average amount outstanding for the period ending October 31, 2026?**

A. Exhibit A-14 (MRB-4), Schedule D-2, shows the long-term debt that was included in developing the 13-month average for the period ending October 31, 2026. The average amount outstanding on line 64, column (j), ties to the 13-month average balance shown on Exhibit A-14 (MRB-2), Schedule D-1a, page 2.

**Q. What is your projection regarding the level of short-term debt balance for the test year ending October 31, 2026?**

A. I have projected an average short-term debt balance for the test year of $201 million. This balance is shown on Exhibit A-14 (MRB-1), Schedule D-1, page 1, line 10, column (b); Exhibit A-14 (MRB-2), Schedule D-1a, page 1, line 10, column (g); and Exhibit A-14 (MRB-5), Schedule D-3, page 1, line 1.

**Q. What are the components of the average short-term debt balance?**

A. Revolvers, commercial paper, and intercompany borrowing are short-term financing options available to the Company. Revolvers are revolving lines of credit that allow the Company to borrow and repay as long as the outstanding balances remain within the credit limits, or capacity. Commercial paper represents debt issuances under the Company's Commercial Paper Program that are short-term in nature, typically 1- to 90-day maturities. Intercompany borrowing represents short-term borrowings from CMS Energy. Intercompany borrowing is drawn under a promissory note with CMS Energy up to $500 million and carries an interest rate of 1-month Secured Overnight Financing Rate

("SOFR")[1] minus 10 basis points. The Company is the beneficiary of intercompany borrowing to meet short-term liquidity needs when it is available and when it is the most cost-effective alternative. It should be noted that the intercompany borrowing facility is not a dedicated financing option that is always available for the Company to use, but only when CMS Energy has surplus cash and effective borrowing rates must be lower than rates available to the Company under the Commercial Paper Program. The intercompany borrowing facility, therefore, is not considered part of the total liquidity capacity available to the Company.

**Q. How was the short-term debt balance of $201 million developed?**

A. Exhibit A-14 (MRB-7), Schedule D-6, shows the projected balances, by month, of short-term debt for the test year ending October 31, 2026. I have arrived at these projections after considering the projected total monthly cash flow requirements, planned long-term debt (net) and equity issuances, and the amount of short-term financing available.

**Q. Are the projections for short-term debt reflected on Exhibit A-14 (MRB-7), Schedule D-6, expected to be issued under the Company's revolvers, its Commercial Paper Program, or its intercompany borrowing agreement?**

A. The Company borrows on its short-term financing facilities in order from least expensive to more expensive. The following is the prioritized order in which the Company utilizes its short-term financing facilities:

[1] SOFR, a benchmark interest rate used in calculating short-term variable interest rates throughout the world. SOFR replaced the London Interbank Offered Rate ("LIBOR") in 2023.

| | | **Amount** | **Credit Capacity** |
|---|---|---|---|
| 1a. | Commercial Paper | $500 million | $500 million* |
| 1b. | Intercompany Borrowing** | $500 million | |
| 2. | Scotiabank Revolver | $250 million | $250 million |
| 3. | JPMorgan Revolver | $1.1 billion | $600 million* |
| | Total | | $1.35 billion |

*Takes away $500 million of the JPMorgan revolver's $1.1 billion capacity (leaving $600 million available).

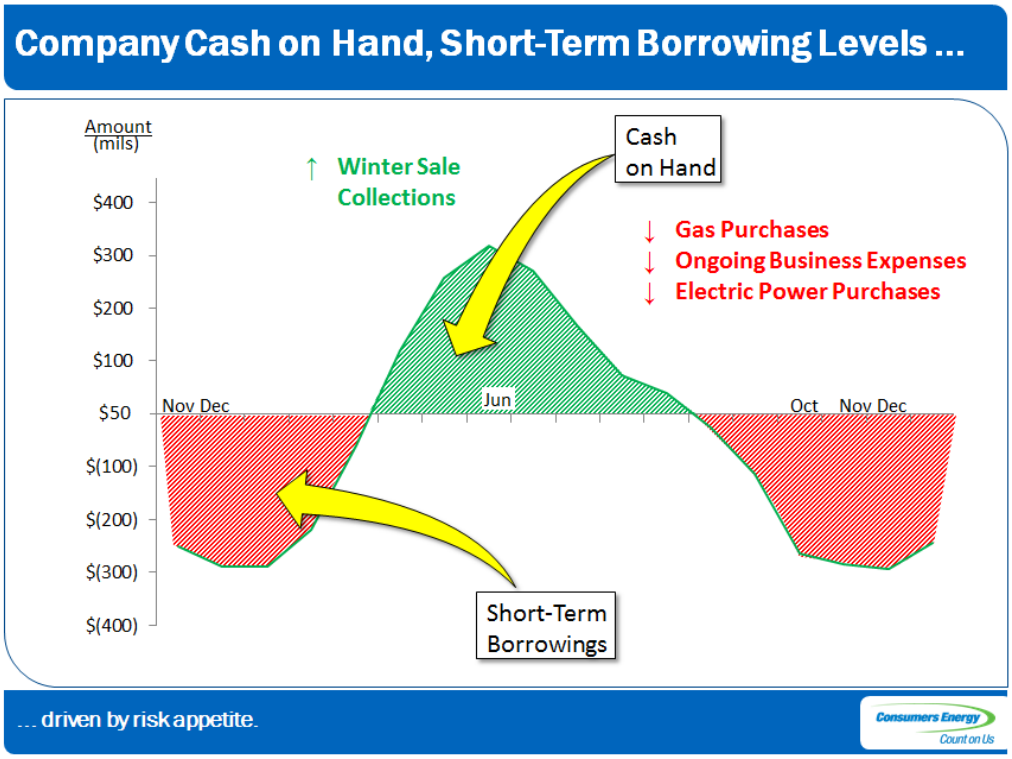
**Intercompany Borrowing or Commercial Paper is used first, depending on availability and which alternative is the most cost-effective at the time of borrowing.

All of the projected test year balances for short-term debt are assumed to be issued under the Company's Commercial Paper Program. This program, along with the intercompany borrowing facility, are the least expensive short-term financing options to the Company and are assumed to be used first when the need arises. The Company's $250 million Scotiabank revolving credit facility is the next least-costly, short-term financing option, with the remaining $600 million revolver ($1.1 billion total capacity less $500 million drawn commercial paper) assumed to be used last.

**Q. How does the timing and amount of short-term borrowings fit into the Company's overall liquidity and financing strategy?**

A. The Company strives to match long-term investments with long-term financing and to finance short-term liquidity needs with its cash and short-term borrowing facilities. The timing and amount of short-term borrowings is directly related to the level of cash on hand. Due to the seasonal nature of utility cash inflows and outflows, the Company generally holds more cash in the spring and summer months and relies on short-term borrowing in

the fall and winter months. Throughout the year, however, a minimum level of cash on hand is maintained. This is reflected in the following chart which depicts the typical cash and short-term borrowing levels through a given year:




**Q. In order to reduce costs, would the Company consider maintaining a permanent layer of short-term debt?**

A. No. Short-term financing markets can be volatile and, at times, access to those markets completely disappear, as was witnessed during the 2008 credit crisis, again in March 2020 as a result of pandemic-related market fear, and again in March 2023 during the banking industry turmoil described earlier in my testimony. Based on the experience and judgment of the Company's Treasury Department, as well as members of the Financial Planning and Analysis Department, the Company does not pursue a strategy that maintains a permanent balance of short-term debt. However, the Company does fund seasonal fluctuations in its working capital with short-term debt as previously illustrated. Based on historical trends

of these seasonal fluctuations, the difference between the maximum working capital surplus and the maximum level of working capital deficiency (peak-to-valley) is approximately $300 million to $600 million. The Company is generally comfortable financing between $200 million and $400 million of this gap with short-term borrowings as doing so leaves adequate undrawn capacity in the event of financial market volatility or disruption. In addition, rating agencies assess the Company's liquidity as a component of their overall credit rating methodology. Reducing cash balances and relying consistently on short-term borrowings would weaken the Company's liquidity metrics. Finally, if the Company were to establish and maintain a permanent level of short-term debt, this should be taken into account in calculating the appropriate equity ratio in this case. If the short-term debt balance were included in the debt-to-equity ratio calculation, the required equity balance would need to increase in order to achieve the appropriate 50.75% equity ratio. Doing so would result in a higher overall cost of capital.

**Q. How does the Company balance the benefit of carrying sufficient liquidity with the cost of maintaining its short-term credit capacity?**

A. The Company's projected $1.35 billion total short-term credit capacity is reasonable and necessary to conduct daily operations and also to keep credit risk at a reasonable level. To maintain strong financial health, it is important for the Company to maintain adequate short-term financing capacity for normal business operations while retaining an adequate amount of additional liquidity for cases of extreme market fluctuations or other unforeseen circumstances. As shown in Exhibit A-14 (MRB-7), Schedule D-6, the Company projects up to $490 million of short-term borrowings, utilizing most of the $500 million capacity of the Commercial Paper Program. Access to the commercial paper market, however,

requires an equivalent amount of revolving credit capacity as a "backstop"; therefore, of the Company's $1.35 billion of revolving credit facilities, $500 million is used to support commercial paper issuance. The remaining $850 million of revolver capacity is a vital backstop for capital expenditures and upcoming long-term debt maturities.

**Q. Did the dramatic increase in natural gas prices in 2022 serve as an example of the importance of the Company holding sufficient short-term credit capacity?**

A. Yes. The Company generally funds its natural gas purchases using short-term borrowing. Surging demand in the United States combined with national inventory levels below historical averages drove gas prices higher in 2022. In addition, Russia's invasion of Ukraine and the related energy market disruptions further increased gas prices. As a result, the Company had to purchase natural gas at significantly higher prices. In fact, the Company held over $1 billion in short-term debt in November and December 2022, as previously described. While the Company was able to secure a $1 billion term loan in July 2022 to meet the excessive short-term borrowing requirements, access to this type of facility at reasonable interest rates is not guaranteed in the future, particularly during times of extreme capital market volatility or the inability to access those markets as described earlier in my direct testimony. The dramatic increase in gas prices in 2022 and the resulting elevated short-term borrowing levels highlights the importance of maintaining sufficient short-term credit capacity to ensure that the Company is able to adequately fund gas purchases, continue operations, and serve customers.

**Q. Consistent with previous rate cases, has the Company included the renewable liability balance in its projected short-term debt balance?**

A. No. Consistent with the Company's RE Plan in Case No. U-21816 filed in November 2024, a renewable liability balance is not expected through the test year of this case. As described earlier in my direct testimony, the capital structure in general rate cases is composed of financing components used to fund its operations and capital investment and includes debt, equity, and deferred income tax balances. Since it would be inappropriate to include an asset balance, the Company has thus excluded this component from the projected capital structure.

**Q. Please explain the deferred income tax adjustment of $526 million.**

A. The Company's Tax Department has projected that the average deferred income tax balance for the test year ending October 31, 2026, will be $526 million higher than the December 31, 2023 balance. This increase is based on projecting book versus tax differences that the Company expects to record from January 2024 through October 2026. These adjustments total $526 million on a 13-month average basis for the test year. The development of the 13-month average deferred income tax balance is shown on Exhibit A-14 (MRB-2), Schedule D-1a, page 4.

**Q. How was the ITC balance determined?**

A. The Company's Tax Department has projected that the average ITC balance for the test year ending October 31, 2026 will be $115 million, $11 million lower than the December 2023 balance of $126 million. The balance is based on forecasted balances of both existing and anticipated new ITC credits that the Company expects to record from January 2024

through October 2026. These adjustments total $(11) million on a 13-month average basis for the test year.

**Q. What balances did you use for ITC in the proposed capital structure?**

A. I allocated the components for ITC based upon the allocation of long-term debt, preferred stock, and common equity in the recommended capital structure.

### B. Development of Cost Rates

**Q. Please explain the development of the total weighted cost of capital shown on Exhibit A-14 (MRB-1), Schedule D-1, page 1, line 19, column (g).**

A. Column (d) represents the percentage of total capital provided by each of the components of the capital structure shown in column (a). These percentages were developed by dividing the amounts of capital shown in column (b) by the total ratemaking capitalization amount shown in line 19, column (b). Column (e) presents the costs, on a ratemaking basis, of each of the components in total ratemaking capitalization. Column (g) is the after-tax weighted cost of capital and is calculated by multiplying column (d) by column (e). The pre-tax weighted cost is shown in column (i) and is calculated by multiplying column (g) by the conversion factors in column (h).

#### i. Long-Term Debt Cost Rate

**Q. What long-term debt annual cost rate did you use in this case?**

A. I developed a 4.35% annual cost for long-term debt. The development of this annual cost rate is shown on Exhibit A-14 (MRB-4), Schedule D-2. Consistent with past Commission practice, the costs are determined on a net proceeds basis. I began with the debt issuances outstanding as of December 31, 2023. I then added the new debt issuances in January 2024 and August 2024. I then added the planned new debt issuances in May 2025, August 2025,

May 2026, and August 2026. These new debt issuances are shown on Exhibit A-14 (MRB-4), Schedule D-2, lines 44 through 47.

**Q. Why did you use cost on a net proceeds basis?**

A. Not reflecting costs on a net proceeds basis would understate costs. The net proceeds methodology accounts for underwriters' compensation and finance expenses. The fees and expenses are shown as a reduction in proceeds from the issuance of new securities, thereby increasing the cost of the issuance over the stated coupon rate.

**Q. Please explain the cost rate you assumed for the planned debt issuances in May 2025, August 2025, May 2026, and August 2026.**

A. I assumed that all of the planned debt issuances will be 30-year bonds with a fixed coupon (interest) rate. To calculate the total interest rate (coupon) projection for these bonds, I started with the projected 30-year U.S. Treasury rate. For each of these planned debt issuances, I then added a 136 basis point credit spread. These interest rate calculations are shown on Exhibit A-14 (MRB-4), Schedule D-2.

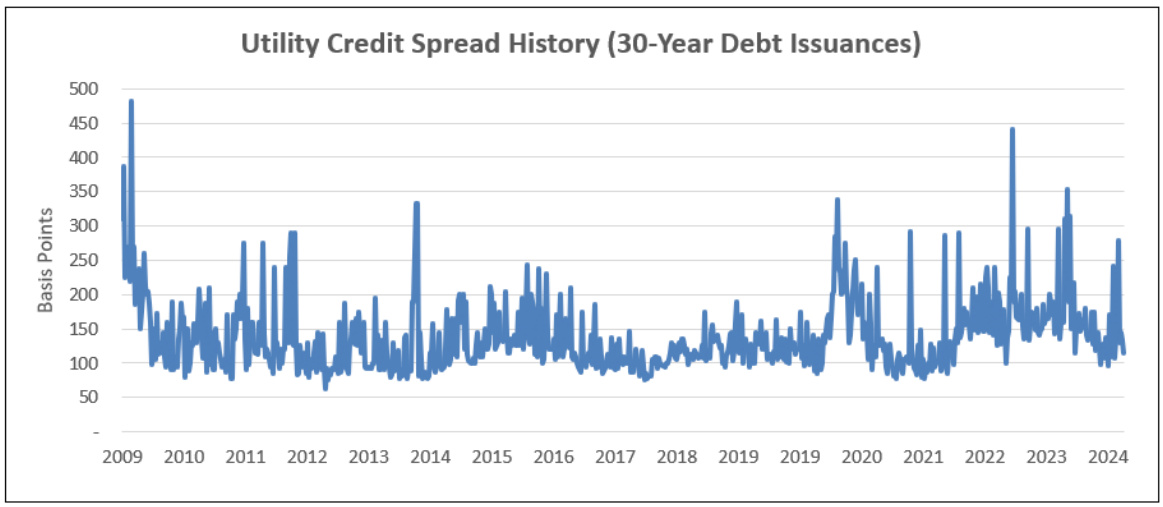
**Q. What is a credit spread?**

A. A credit spread reflects the compensation investors receive for bearing credit risk of the investment in addition to the underlying Treasury rate. The total interest rate on a corporate bond is the summation of both the Treasury rate and the credit spread.

**Q. How did you calculate the credit spread of 136 basis points?**

A. Unlike U.S. Treasury rates, credit spreads for long-term bond issuances are not projected by financial forecasting companies. This is because spreads are very difficult to predict. Interest rate spreads are based on a number of factors, most notably the Company's credit rating and the market conditions at the time of the debt issuance, including both same-day

and short-term supply/demand dynamics. In addition, credit spreads can be quite volatile in short periods of time. The volatility of credit spreads is illustrated on the following chart:




Given the lack of a reliable source for projected credit spreads, I applied the calculated average from the last 15 years. From 2009 to Mid-October 2024, the average credit spread on a 30-year debt issuance for investment grade utilities was approximately 136 basis points. This credit spread is very reasonable in relation to the historical spreads for 30-year debt issuances, as evidenced in the chart above.

**Q. Are there any existing long-term debt issuances that have variable interest rates?**

A. Yes. There are three debt issuances shown on Exhibit A-14 (MRB-4), Schedule D-2, which have variable interest rates. The Floating Rate First Mortgage Bonds ("FMB") issuances shown on line 27 and lines 30 through 31 have variable interest rates.

**Q. What cost rates did you use for these variable rate issuances?**

A. The interest rate for the Floating Rate FMB issuances is equal to SOFR less 30 basis points. Therefore, I took the projected three-month SOFR for the test year in this case (equal to 3.36%) and subtracted 30 basis points for an interest rate of 3.06%.

**Q. Please explain Exhibit A-14 (MRB-4), Schedule D-2, line 58.**

A. Exhibit A-14 (MRB-4), Schedule D-2, line 58, represents the amortization of losses on reacquired Consumers Energy debt (including call premium) for refinancings. This amortization needs to be added to the interest cost on the refinanced debt to determine Consumers Energy's true financing cost for the long-term debt. The Commission recognized recoverability of these costs in establishing the cost rate in Case No. U-16794.

**Q. How did you calculate the amount shown on Exhibit A-14 (MRB-4), Schedule D-2, line 58?**

A. The amount shown on line 58 represents the amortization of losses on reacquired debt with refunding (including call premiums). The projected amortization expense for the 12-month period ending October 2026 is $4,305,000.

**ii. <u>Short-Term Debt Cost Rate</u>**

**Q. What short-term debt cost rate did you use in this case?**

A. I used a short-term debt cost rate of 4.52%. This cost rate is shown on Exhibit A-14 (MRB-5), Schedule D-3, page 1, line 5.

**Q. Please explain the cost of short-term debt.**

A. I projected a cost of short-term debt of $9.1 million. The development of this cost is shown on Exhibit A-14 (MRB-5), Schedule D-3, page 2. The cost of short-term debt – revolver has four components:

1. **<u>Interest on Borrowings</u>** – Equal to the projected outstanding balance times the projected interest rate. The projected balance, all assumed to be commercial paper, is $201.4 million, calculated on Exhibit A-14 (MRB-7), Schedule D-6. Commercial paper issuances are short term in nature, typically 1- to 90-day maturities. Interest charged on these short-term borrowings are based on several different factors, including market conditions, investor demand, and the tenor (number of days borrowed) of the issuance. I approximated the interest on commercial paper borrowings using the projected SOFR rate for the test year

of 3.36%. This was multiplied by the projected balance of $201.4 million. Exhibit A-14 (MRB-5), Schedule D-3, page 2, shows the projected cost of $6.8 million for borrowings under the Commercial Paper Program;

2. **Letter of Credit Fees** – Equal to the projected Letters of Credit outstanding times a rate set forth by the facility the Letters of Credit are issued under. Exhibit A-14 (MRB-5), Schedule D-3, page 2, shows the projected cost of $0.7 million for Letter of Credit Fees. The Letter of Credit Fees shown on Exhibit A-14 (MRB-5), Schedule D-3, page 2, pertain to normal business Letters of Credit to cover ongoing items such as fuel purchases or margin support and also Letters of Credit to cover Midcontinent Independent System Operator, Inc. margin obligations;

3. **Unused (Commitment) Fees** – This cost consists of Annual Revolver Commitment Fees, which the Company is required to pay quarterly to the banks on the "unused" portion of the JPMorgan revolver and the Scotiabank revolver, and other required annual fees under the Revolving Credit agreements. The Revolver Commitment Fees are associated with maintaining fund availability. It should be noted that borrowings under the Company's Commercial Paper Program reduce the "availability" (or the amount the Company is able to draw) of the JPMorgan revolver but do not reduce the "unused" portion of the revolver in calculating the unused (commitment) fees. Exhibit A-14 (MRB-5), Schedule D-3, page 2, shows the projected cost of $0.9 million for commitment fees; and

4. **Amortization/Expense of Facility Fees** – At the inception of a revolving credit facility, the borrower is required to pay upfront fees and issuance costs to the lenders. These issuance and upfront costs are amortized over the life of the revolver. For the Commercial Paper Program, there are annual fees required to maintain the facility. Exhibit A-14 (MRB-5), Schedule D-3, page 2, shows the projected cost of $0.7 million for amortization of upfront revolver fees.

**Q. Why is it important to allow for the recovery of commitment fees and amortization of facility fees in addition to the interest on short-term borrowings and interest on letters of credit?**

A. These fees and costs are customary in revolving credit facilities and commercial paper agreements and are necessary to secure the financing and to keep the facilities available for the financing needs of the Company. The Company cannot avoid incurring these costs except by giving up the short-term borrowing facilities, which would not be a sound business decision. If these fees are not recovered through short-term debt cost, then they

need to be recovered as part of long-term debt cost. The cost of short-term debt – short-term credit facilities represents the cost to provide $1.35 billion of necessary liquidity to Consumers Energy.

**iii. Preferred Stock Cost Rate**

**Q. What is the annual cost of preferred stock?**

A. The annual cost of preferred stock is shown on Exhibit A-14 (MRB-6), Schedule D-4. This cost is 4.50%.

**iv. Common Equity Cost Rate**

**Q. What rate did you use for the cost of common equity?**

A. Based on my recommended equity ratio of 50.75%, I applied a cost rate of 10.25% for common equity. As explained earlier in my testimony, to the extent that the Commission authorizes a lower equity ratio than that proposed by the Company, a higher ROE is necessary to prevent the potential for adverse credit impacts. The Company's capital structure and ROE recommendations in this case reflect the appropriate levels that the Commission should adopt with that principle in mind in order to preserve Consumers Energy's current credit rating.

**v. Other Cost Rates**

**Q. What cost rates did you use for the remaining components of the capital structure?**

A. Consistent with MPSC ratemaking practice, deferred income taxes are included at zero cost. The cost rates for each of the three components of ITC correspond to the cost rates for long-term debt, preferred stock, and common equity.

## III. EXHIBITS FOR CERTAIN FILING REQUIREMENTS – CREDIT RATINGS, AND RECENT UTILITY BOND ISSUANCES

**Q. Please describe Exhibit A-30 (MRB-8).**

A. Exhibit A-30 (MRB-8) is included per the rate case filing requirements. In its December 23, 2008 Order in Case No. U-15895, the Commission directed that utilities include an exhibit that provides current and historical credit ratings with associated outlooks for the previous five years for the utility and its parent company. Exhibit A-30 (MRB-8) shows Consumers Energy's and CMS Energy's current and historical credit ratings, along with associated credit outlooks, for the previous five years as published by S&P, Moody's, and Fitch Ratings. The credit ratings include senior secured debt, commercial paper, senior unsecured debt, preferred stock, junior subordinated debt, hybrid preferred securities ratings, and preferred stock ratings.

**Q. Please describe Exhibit A-31 (MRB-9).**

A. In its December 23, 2008 Order in Case No. U-15895, the Commission directed that utilities include an exhibit that provides certain information related to bond issuances. Exhibit A-31 (MRB-9) shows recent public utility corporate bond issuances for a period of three months prior to and three months subsequent to, each of Consumers Energy's long-term public debt offerings issued during the 24 months prior to the date of the Application in this rate case. This summary includes the issue date, issuing company, type of offering (either secured or unsecured), amount of offering, coupon rate, S&P and Moody's credit ratings, maturity date, and spread on U.S. Treasury.

## IV. PROJECTED CASH BALANCE

**Q. Do you believe that the projected cash balance for the test year ending October 31, 2026, should be based on the 13 months ended June 30, 2024 (the working capital historical period)?**

A. No. Using the 13 months ended June 2024 results in a cash balance of $7.3 million, which is lower than what is normally expected and required for the Company in the test year of this case.

**Q. What do you believe that the projected cash balance for the test year ending October 31, 2026 should be based on?**

A. I believe that the projected cash balance for the test year in this case should equate to approximately 1% of test year gas revenues, which results in a cash balance of $28.4 million. This is reflective of normal levels of cash balance.

**Q. Has the Commission addressed the reasonableness of the Company's cash balance projection equal to approximately 1% of revenues?**

A. Yes. In Case No. U-21389, the Administrative Law Judge ("ALJ") agreed with the Company that "the use of 1% of revenues as a benchmark for working capital cash is not arbitrary or inapplicable to determining the reasonableness of the amount of cash on hand." In its March 2024 Opinion in this case, the Commission found the ALJ's recommendation to be "well-reasoned and supported by the record."

## V. SUMMARY AND CONCLUSIONS

**Q. Please summarize your recommendations and conclusions.**

A. Consumers Energy's capital structure should be based on the capital structure as of December 31, 2023, adjusted for the known and expected changes in long-term debt,

common equity, short-term debt, deferred income taxes, and ITC, as shown on Exhibit A-14 (MRB-1), Schedule D-1. The cost rates developed are fair and reasonable and commensurate with the risks for the period of time rates are expected to be in effect. As shown on Exhibit A-14 (MRB-1), Schedule D-1, I recommend an overall after-tax rate of return of 6.22%. Also, the Company's projected cash balance for the test year in this case should be based on approximately 1% of test year gas revenues, which results in a balance of $28.4 million.

**Q. Does this conclude your direct testimony?**

A. Yes.

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

| | | |
|---|---|---|
| In the matter of the application of<br>**CONSUMERS ENERGY COMPANY**<br>for authority to increase its rates for the<br>distribution of natural gas and for other relief. | )<br>)<br>)<br>)<br>) | Case No. U-21806 |

**REBUTTAL TESTIMONY**

**OF**

**MARC R. BLECKMAN**

**ON BEHALF OF**

**CONSUMERS ENERGY COMPANY**

May 2025

**Q. Please state your name and business address.**

A. My name is Marc R. Bleckman, and my business address is One Energy Plaza, Jackson, Michigan 49201.

**Q. Are you the same Marc R. Bleckman who previously filed direct testimony in this case on behalf of Consumers Energy Company ("Consumers Energy" or the "Company")?**

A. Yes, I am.

**Q. What is the purpose of your rebuttal testimony?**

A. The purpose of my rebuttal testimony is to provide rebuttal to certain aspects of the direct testimonies of: (i) Michigan Public Service Commission ("MPSC" or the "Commission") Staff ("Staff") witnesses Kirk D. Megginson and Justin J. Hecht; (ii) Attorney General Dana Nessel ("AG") witness Sebastian Coppola; and (iii) Association of Businesses Advocating Tariff Equity ("ABATE") witness Christopher C. Walters.

**Q. How is your rebuttal testimony organized?**

A. In Section I, I will provide rebuttal to portions of the direct testimony of Staff witness Megginson and Staff witness Hecht. In Section II, I will provide rebuttal to portions of the direct testimony of AG witness Coppola. In Section III, I will provide rebuttal to portions of the direct testimony of ABATE witness Walters.

**Q. Are you sponsoring any exhibits in connection with your rebuttal testimony?**

A. Yes. I am sponsoring the following exhibits:

| | |
|---|---|
| Exhibit A-114 (MRB-17) | S&P January 14, 2025 Report; |
| Exhibit A-115 (MRB-18) | MPSC Staff's Answer to Consumers Energy's Second Discovery Request; |
| Exhibit A-116 (MRB-19) | S&P August 20, 2024 Credit Report; |

| | |
|---|---|
| Exhibit A-117 (MRB-20) | Moody's May 31, 2024 Credit Report; and |
| Exhibit A-118 (MRB-21) | Attorney General's Answer to Consumers Energy's Third Discovery Request. |

**Q. Were these exhibits prepared by you or under your direction or supervision?**

A. Yes.

## I. REBUTTAL OF STAFF WITNESSES MEGGINSON AND HECHT

### A. Overview of Areas of Disagreement Addressed

**Q. What aspects of Staff's recommendations are you rebutting?**

A. I am rebutting Staff's projected common equity balance and the resulting common equity ratio. I am also rebutting Staff's projected cost of long-term debt. Finally, I am responding to Staff's proposed adjustment to the Company's working capital cash balance.

**Q. Are there any other aspects of Staff's recommended capital structure that the Company disagrees with?**

A. Yes. Consumers Energy does not agree with Staff's recommended Return on Equity ("ROE") of 9.75%. This issue, however, is addressed in the rebuttal testimony of witness Ann E. Bulkley, the Company's ROE witness in this case.

### B. Rebuttal to Staff's Recommendation Regarding the Common Equity Ratio

**Q. Do you agree with Staff's projected common equity ratio of 50.00%?**

A. No. Staff's recommended common equity ratio for the test year in this case is understated. My rebuttal testimony to Staff's recommended equity ratio is organized as follows:

i. Staff Incorrectly Interprets the Company's Credit Ratings and Regulatory Environment

ii. Staff Fails to Consider New Circumstances That Justify a Deviation From a Balanced Capital Structure

iii. Staff Ignores the Potential Negative Financial Impacts of a Lower Equity Ratio

iv. Staff Fails to Consider the Average Equity Ratios of Peer Group Companies

v. Summary

**i. Staff Incorrectly Interprets the Company's Credit Ratings and Regulatory Environment**

**Q. On page 6 of his direct testimony, Mr. Megginson minimizes the importance of Moody's downgrade of the Company's credit rating by stating that the downgrade "put the Company's credit rating more in line with the other two agencies ratings." Mr. Megginson also concludes that "the prior Moody's rating appeared to be an outlier." Do you agree with these statements?**

A. No. Each of the credit rating agencies maintains its own ratings methodology and credit rating scale. It is not a universal measure in which the specific credit rating assigned by Moody's, for example, can be directly compared to the credit rating assigned by Standard and Poor's ("S&P") or Fitch. If Mr. Megginson's assertion were true, there would not be a need for more than one rating agency, as all credit rating methodologies and credit rating scales would be the same. Also, Mr. Megginson's attempt to downplay the credit ratings downgrade by implying that it was an inconsequential action should be rejected by the Commission. Each of the Company's debt offerings are rated by the three main rating agencies – Moody's, S&P, and Fitch. A lower credit rating indicates higher risk which, in turn, necessitates a higher interest rate to compensate for that risk. Regardless of the presumed comparative credit ratings between the different credit rating agencies, the fact that the Company's credit rating was downgraded by Moody's was a negative event that had negative financial consequences for the Company and for customers who bear the cost of capital.

**Q. Starting on page 6 of his direct testimony, Mr. Megginson describes the impact of the Company's regulatory environment on its credit rating. Mr. Megginson also references credit reports in which the Company's regulatory environment has been described as positive. Does this give support to Mr. Megginson's recommendation to reduce the Company's equity ratio to 50.00% for the test year in this case?**

A. No. I believe that Mr. Megginson's assessment of the Company's regulatory environment is incomplete. In his direct testimony, Mr. Megginson references aspects of Michigan's regulatory framework that have been established for several years under the 2008 and 2016 energy legislation, including items such as a forward-looking test year and the 10-month rate case process. Mr. Megginson's assessment fails to capture the results from the Company's most recent rate cases which demonstrate a sharp decline in authorized weighted rate of return (ROE times equity ratio) following a long period of stability. This recent shift is illustrated in the table on page 15 of my direct testimony. In addition, while rating agencies have described the Company's regulatory environment in a positive light, this rating is continuously evaluated. The persistent decline in the Company's authorized weighted rate of return since 2020 could be seen as a material deterioration in the credit supportiveness of the Michigan regulatory environment. Mr. Megginson fails to acknowledge that the Company's positive regulatory environment in past years has been fueled in large part by authorized ROE and equity ratios that were significantly higher than currently proposed by Staff for the Company in this case. In fact, the trend in rate orders with regard to authorized ROE and equity ratio was a cause for concern for Moody's in its downgrade of the Company's credit rating. An equity ratio of 50.75% and an ROE of

10.25% is better aligned with rate of return levels prior to the Company's credit rating downgrade and is therefore supportive of adequate credit quality at this time.

**Q. Is there evidence that analysts have started to recognize a decline in the state of the Company's regulatory environment?**

A. Yes. Refer to Exhibit A-36 (MRB-14), S&P's State Regulatory Evaluations – Energy. In August 2024, S&P lowered its ranking of Michigan's regulatory environment from "Above Average" to "Average." In downgrading its state regulatory rating, S&P referenced recent rate case decisions in Michigan including authorized ROEs which "compare less favorably" to prevailing industry averages and a "tightening in the regulatory climate." Also refer to pages 20 to 21 of my direct testimony. In updating its regulatory rankings for U.S. utilities in May 2023, UBS moved Michigan down a level from Tier 1 to Tier 2. In describing the negative change, UBS specifically mentioned authorized ROEs as well as a lowering of their "subjective factor" for the Michigan regulatory jurisdiction, which is based on UBS's "knowledge of current commission actions." Refer to Exhibit A-106 (MRB-15). It is apparent that rating agencies and analysts have taken note of the recent trend in the Company's regulatory outcomes with regard to capital structure. A continuation or, even worse, a further degradation of the authorized weighted rate of return puts the Company at risk of dropping further in its regulatory environment rankings which could negatively impact the Company's credit quality and credit rating. Michigan's regulatory standing needs to be protected and bolstered rather than drawn upon to push the Company toward over-leveraging. Broadly speaking, an above average regulatory standing translates into increased potential investment which continues to support affordable utility infrastructure financing for the state of Michigan.

**Q. On page 8 of his direct testimony, Mr. Megginson references a report from S&P's Regulatory Research Associates on state regulatory evaluations. Has S&P provided additional insight with regard to the future credit quality of regulated utilities including Consumers Energy?**

A. Yes. Refer to Exhibit A-107 (MRB-16). In a February 2024 report "Rising Risks: Outlook for North American Investor-Owned Regulated Utilities Weakens," S&P updated their outlook of the regulated utility industry to negative, citing "headwinds to credit quality" including increased cash flow deficits that are funded to a higher extent with debt versus equity. Also refer to Exhibit A-114 (MRB-17). In a January 2025 report on North American regulated utilities, S&P highlighted lower ratings headroom as "a high percentage of companies are operating with only minimal financial cushion from our downgrade threshold." S&P also notes that, in 2024, downgrades among North America's investor-owned regulated utilities outpaced upgrades for the fifth consecutive year. With regards to the industry credit outlook for 2025, S&P identifies the following risks to utilities' credit quality:

- The portion of equity in the industry has been weak and consistently below expectations and thus pressuring the industry's financial measures. S&P states that "without significantly more common equity issuance, we expect the industry's financial measures will continue to weaken, albeit gradually, supporting our negative outlook;"
- Tax legislation could weaken financial measures if the new Republican administration lowers the corporate tax rate, reduces tax credits, or eliminates their transferability; and
- Robust capital spending and challenging regulatory constructs will persist for 2025, further pressuring the industry's credit quality.

S&P also cites Michigan as one of the regulatory jurisdictions that they "continue to carefully monitor." It is apparent from these rating agency reports that an ROE and equity

ratio combination higher than the current authorized level, and certainly higher than the continued degradation proposed by Staff, is critical to protect the Company from receiving a credit downgrade in the light of the credit risks as described above.

**Q. On page 9 of his direct testimony, Mr. Megginson includes a chart showing Consumers Energy's net income from 2010 to 2024 noting that "the Company's net income has risen steadily over the years" which has "enabled Consumers to access credit markets to the tune of billions in short and long-term financing at very competitive rates." Do you agree with Mr. Megginson's interpretation of this data?**

A. No. Mr. Megginson reviews the Company's annual change in net income in complete isolation, without considering the changes in investment over time or the changes in rate base. To the extent that the Company has invested in the system over the period from 2010 through 2024, its net income should increase. However, the analysis does nothing to demonstrate that the increases in net income are sufficient to satisfy the investor-required return on that investment, nor does it conclude anything meaningful about the Company's financial integrity. The Company's access to capital markets and its ability to raise capital at competitive rates is not based on net income, but rather is largely based on the Company's credit quality as determined by credit rating agencies. Since net income can be skewed by non-cash transactions, rating agencies instead look to the Company's cash flow metrics, including its Funds From Operation ("FFO")-to-Debt ratio. Rating agencies also look at the strength of the Company's balance sheet, including its equity ratio. These financial measures are a better indicator of the Company's credit quality and credit rating. It should be noted that the Company's "billions in short and long-term financing" over the years was executed during a period in which the Company's authorized equity ratio was

significantly higher than currently proposed by Staff for the Company in this case. As the Company will continue to rely heavily on capital markets to fund capital investment, the Company's proposed equity ratio of 50.75% will help to maintain strong credit ratings and obtain financing at lower interest rates.

**Q. On page 9 of his direct testimony, Mr. Megginson points to the Company's debt issuances in 2023 and 2024 and projected debt issuances in this case as evidence that the Company has not been negatively impacted by Moody's credit rating downgrade. Do you agree with this conclusion?**

A. No. Neither the Company's ability to issue debt in 2023 and 2024 nor the projection of continued debt issuances in this case is evidence that there has been no negative impacts from Moody's credit rating downgrade. As explained earlier in my rebuttal testimony, a lower credit rating results in negative financial impacts associated with a higher cost of capital. In addition, the Company's debt issuances in 2023 and 2024 do not prove that the Company will undoubtedly have access to capital markets at reasonable rates in the future, especially with a lower weighted rate of return as proposed by Mr. Megginson.

**Q. On page 10 of his direct testimony, Mr. Megginson states that "Consumers currently has a revenue decoupling mechanism in place that allows it to collect revenues, including a return on investment, that is unrelated to the amount of gas sold to its customer base." Mr. Megginson also states that "the Company also has several gas infrastructure improvement and replacement programs in place with surcharge payment mechanisms." Mr. Megginson concludes that programs such as this improve the Company's cash flow expectancy and reduce the Company's risk which,**

**in turn, justifies a reduction in the Company's ROE. Does the Company currently have these mechanisms in place as Mr. Megginson claims?**

A. No, revenue decoupling is no longer a regulatory mechanism that the Company has in place. Refer to Staff's discovery response included as Exhibit A-115 (MRB-18). When asked to identify the MPSC proceeding which authorizes the revenue decoupling mechanism currently in place, Staff changes its position stating that the Company's revenue decoupling mechanism "may have discontinued." In addition, the Company does not have any gas infrastructure improvement and replacement programs with surcharge mechanisms. Again refer to Staff's discovery response included as Exhibit A-115 (MRB-18). When asked to identify the "several gas infrastructure improvement and replacement programs" currently in place, Staff referenced the Company's Enhanced Infrastructure Replacement Program. However, there is no surcharge mechanism in place for this program. Staff also identifies the Company's Gas Cost Recovery mechanism which is simply a method for the Company to recover its cost of gas and is clearly not a gas infrastructure improvement and replacement program. Finally, Staff identifies the Company's Energy Waste Reduction program which is also not a gas infrastructure improvement and replacement program but a state-mandated program aimed at reducing energy consumption and improving energy efficiency. Since Mr. Megginson's claims and references to the existence of recovery mechanisms are false, his argument that such programs reduces risk and thus justifies a lower authorized ROE or equity ratio should be rejected by the Commission.

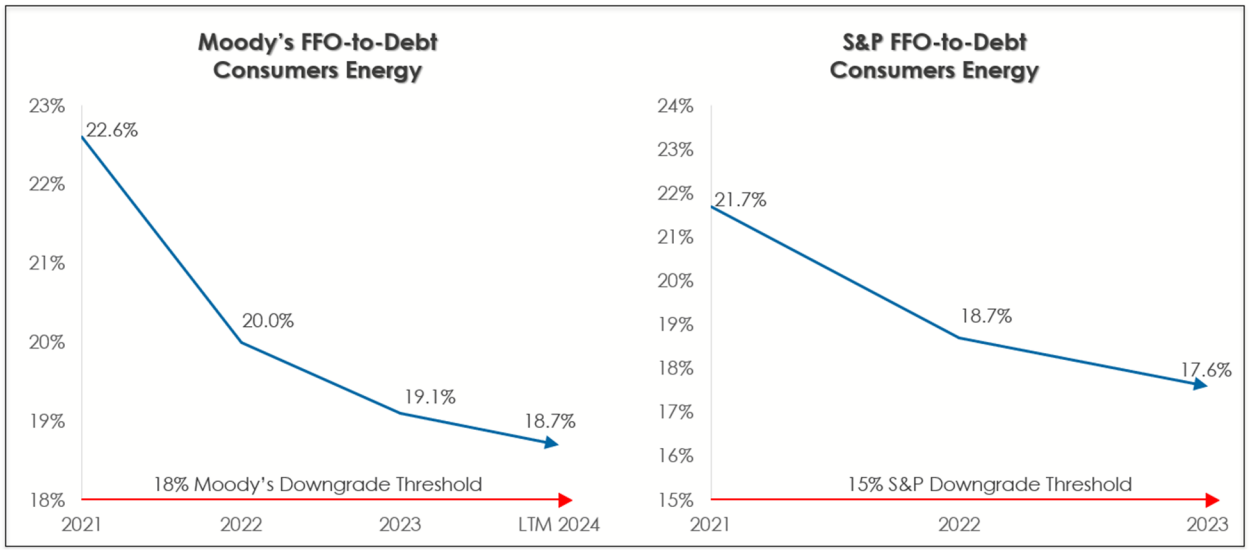
**Q. On pages 10 to 11 of his direct testimony, Mr. Megginson references recent credit opinions from S&P and Moody's which describe the rating agencies' expectations with respect to the Company's FFO-to-Debt ratio in future years. Because the rating agencies' expectations are above the credit downgrade thresholds, Mr. Megginson concludes that "rating agencies don't foresee any major deterioration or long-lasting decline in the FFO-to-Debt ratio for Consumers Energy in the foreseeable future." Do you agree with Mr. Megginson's conclusion?**

A. No. In assessing credit quality, rating agencies must make certain assumptions with respect to the Company's outlook, including future financial results and regulatory outcomes. However, the assumption of credit metrics holding above the downgrade threshold should not be interpreted as assurance that these assumptions will ultimately materialize, with no risk of a credit rating downgrade. For example, in June 2019, Moody's issued a credit opinion for the Company stating that "Consumers' stable outlook reflects our expectation that the Michigan legislative and regulatory environments will remain constructive." Moody's also stated that they expected the Company's FFO-to-Debt ratio to "range between 20% and 24% over the next few years." In May 2021, Moody's downgraded Consumers Energy's credit rating "due to its weakened credit metrics." Moody's also referenced the outcome of recent rate cases which put pressure on the Company's credit metrics. While rating agencies may assume that the Company will continue to operate in a constructive regulatory environment with credit metrics above the downgrade threshold, the Company's credit rating is continuously evaluated. A reduction in the Company's rate of return lowers cash flow, increases debt, and thereby weakens the Company's FFO-to-Debt ratio. These negative credit metric impacts place the Company's credit quality and

credit ratings at risk. The authorized ROE and equity ratio in this case will be a key component of future rating agency evaluations.

**Q. In his assessment of the Company's credit ratings and credit quality did Mr. Megginson take into account the trend in the Company's FFO-to-Debt ratio in recent years?**

A. No. Refer to page 5 of S&P's August 2024 credit opinion shown on Exhibit A-116 (MRB-19). The Company's FFO-to-Debt ratio as calculated by S&P has been trending down in recent years from 21.7% in 2021 to 17.6% in 2023, a decrease of 410 basis points and, for 2023, just 60 basis points above the low end of S&P's expected range outlined in its report. In addition, refer to page 2 of Moody's May 2024 credit opinion shown on Exhibit A-117 (MRB-20). The Company's FFO-to-Debt ratio as calculated by Moody's has also been trending down in recent years from 22.6% in 2021 to 19.1% in 2023, a decrease of 350 basis points. Moody's May 2024 credit report also shows a further decline to 18.7% for the 12 months ended March 2024. It is clear from this report that the Company's FFO-to-Debt ratio as calculated by Moody's is trending down and was well below the low end of Moody's expected range (20-21%) for the Company for 2023 and for the 1st quarter of 2024. These credit metric results are shown in the following chart:




The Company's FFO-to-Debt ratio has been trending down in recent years, moving closer to the rating agencies' credit downgrade thresholds. As the credit metric cushion decreases, the Company's credit rating becomes more at risk for a downgrade. The ROE and equity ratio combination proposed by the Company in this case is critical in protecting the Company from a credit downgrade in the light of the credit metric degradation shown above.

### ii. Staff Fails to Consider New Circumstances That Justify a Deviation From a Balanced Capital Structure

**Q. On pages 13 to 15 of his direct testimony, Mr. Megginson references the Commission's Orders in prior rate cases which reflected its desire for the Company to have a balanced equity ratio. Is this evidence that the Company's equity ratio in the current case should necessarily be 50% as Mr. Megginson proposes?**

A. No. The appropriate equity ratio for the Company should be based on the facts and circumstances presented in the current case and not predetermined based on prior Commission orders. While the Commission voiced its desire for the Company to move

toward a balanced capital structure in the cases referenced by Mr. Megginson, the Commission has also made clear that there should be flexibility in its assessment, allowing for a deviation from a balanced capital structure when circumstances warrant it. This approach is illustrated in the following Commission Orders:

> **Case No. U-17990** – "A more complete analysis should be included to explain why such a result is reasonable and prudent" (when referring to an unbalanced capital structure). [MPSC Case No. U-17990, February 28, 2017 Order, page 64.]
>
> **Case No. U-20963** - "The Commission maintains its goal of a capital structure evenly balanced between debt and equity, while continuing to allow a utility to present arguments why a deviation from this ratio is appropriate. As it has done in previous rate cases, the Commission will continue to consider all evidence and circumstances in each rate case to determine the appropriate capital structure." [MPSC Case No. U-20963, December 22, 2021 Order, page 200.]
>
> **Case No. U-21585** - "The Commission, like the ALJ, acknowledges that there is some degree of flexibility and 'that the aspirational goals expressed in previous Commission orders are not permanently binding and that any target for the Company's capital structure should change if evolving circumstances indicate that the target is no longer a sound policy.'" [MPSC Case No. U-21585, March 21, 2025 Order, page 232.]

It is clear from previous orders that the Commission does not consider a balanced capital structure a mandate to be followed blindly, but rather as a basis from which a deviation may be justified upon consideration of the evidence and circumstances of each rate case.

**Q. Has the Company presented evidence in this case that an equity ratio of 50.75%, slightly above a balanced capital structure, is warranted?**

A. Yes. Refer to pages 10 through 23 of my direct testimony in which I outline reasons why an equity ratio of 50.75% and an ROE of 10.25% as proposed by the Company in this case are well-measured for both the Company and its customers, while still mindful of the Commission's previous orders. This capital structure results in a modest effect on customer rates while bringing the Company more in-line with the authorized weighted rate

of return experienced toward the beginning of the COVID-19 pandemic and prior to the most recent credit rating downgrade. The weighted rate of return as proposed in this case strengthens the Company's balance sheet and credit quality, which will be critical in delivering the Reliability Roadmap investments while doing so in the midst of an elevated interest rate environment.

**Q. Are there any new circumstances that give weight to the Company's contention that a deviation from a balanced capital structure to 50.75% equity is justified at this time?**

A. Yes. A high degree of volatility and economic uncertainty has emerged in recent months with respect to financial markets, interest rates, and geopolitical tensions. The Trump administration, signaling a significant shift in American trade policy, has placed significantly higher tariffs on imported goods, causing a substantial impact on the U.S. economy. Companies reliant on global supply chains faced elevated input costs, which translated into higher consumer prices and contributed to sustained inflationary pressures. In addition, the heightened trade tensions created an atmosphere of uncertainty that negatively affected business investment and led to heightened volatility in financial markets. An April 2025 Wall Street Journal article titled "Huge Stock Swings Are the New Normal for Frazzled Investors" stated that April 2025 is poised to be the most-volatile calendar month since the COVID crash in 2020. The VIX, a stock market index that measures investors' expectation of volatility, peaked at 52.33 on April 8, 2025. The VIX has not reached 50.00 since April 2020 during the height of the COVID-19 pandemic. Fears of a sharp economic downturn have also dramatically increased. In April 2025, J.P. Morgan Research raised the probability of a U.S. recession occurring in 2025 to 60%.

These developments represent a material change in the Company's risk environment since the previous Commission orders that will most likely continue through the test year of this case. During this period of heightened risk and volatility, it will be critical for the Company to have an authorized ROE and equity ratio that is supportive of its good credit quality. This will be instrumental in the Company's ability to maintain uninterrupted access to needed liquidity and better withstand potential impacts from fuel price spikes, inflationary pressures, and tightening capital markets. As provided for in previous Commission orders, an equity ratio of 50.75% (slightly above a balanced capital structure) is warranted given the facts and circumstances present in the current case.

### iii. Staff Ignores the Potential Negative Financial Impacts of a Lower Equity Ratio

**Q. Starting on page 15 of his direct testimony, Mr. Megginson references the relatively higher cost of equity compared to debt as justification for a lower equity ratio. Does Staff also discuss the potential negative financial impacts of a lower equity ratio?**

A. No. Staff merely states that it is important to "establish a proper equity to debt ratio to maintain reasonable costs to ratepayers." Staff makes this conclusion without analyzing or quantifying the increased costs to the Company and customers that would certainly result from further credit downgrades. Additionally, Mr. Megginson does not provide quantifiable justification as to why his chosen equity ratio of 50.00% is appropriate. This outcome-based conclusion, which is void of an evidentiary analysis of the resulting financial impacts to the Company and its customers, should not be accepted by the Commission.

**Q. Mr. Megginson argues that because equity is more expensive than debt, it necessitates a lower equity ratio. Does this rationale have merit?**

A. No. Taken to extreme, this rationale would lead to Staff simply recommending that because customers would benefit most from 0% equity, the Commission should authorize a completely debt financed capital structure for the Company. Such a result would clearly ruin the financial soundness of the Company and a recommendation based on such a rationale should be given no merit. Staff's argument points out the obvious fact that the cost of equity is greater than the cost of debt – but no business can or should fund itself with an excessive level of debt. This simplistic argument adds nothing of value for the Commission to consider.

**Q. Although Mr. Megginson chooses to ignore the possibility of another credit downgrade and presents no analysis or discussion of the impacts of a credit downgrade on the Company, what would be the effect of a credit downgrade?**

A. As explained earlier in my rebuttal testimony, lowering the equity ratio and authorized ROE reduces the Company's overall cost of capital and rate of return. This, in turn, lowers the Company's cash flow and FFO-to-Debt ratio. The Company would also have to increase its long-term debt to achieve a lower equity ratio thereby weakening the Company's FFO-to-Debt ratio. The negative impacts could cause the Company's FFO-to-Debt ratio to drop below the established rating agency thresholds, placing both the Company's credit quality and credit ratings at risk. While it may seem attractive for the benefit of customers in the near-term to minimize the equity layer of the Company, such a move, and the potential resulting credit rating downgrade, could lead to the Company's customers paying higher financing costs over the long term, and it could put at risk the

Company's ability to execute on its critical investment plan on behalf of customers. Thus, it is of great importance for the regulatory response to be balanced and thoughtful, as the financial health of the Company is a critical element of its ability to implement the capital plan needed to deliver safe, reliable, and clean energy to its customers.

**Q. What are the customer benefits of the Company maintaining the needed financial cushion to avoid a credit rating downgrade?**

A. A higher credit rating ensures that the Company is able to obtain financing at lower interest rates, resulting in long-term customer rate stability. As shown in Exhibit A-35 (MRB-13), the Company has saved customers $153 million annually as a result of improved credit ratings and lowered interest costs. But the customer benefits extend far beyond this long-term rate stability. As set forth in the testimony and exhibits of the Company's multiple capital witnesses, the Company is making significant capital investments to maintain and improve utility infrastructure to improve reliability and resiliency to the benefit of customers. During this time, the Company must rely heavily on the capital markets to fund these investments. Therefore, it will be especially important for the Company to maintain strong credit ratings to ensure beneficial access to capital markets for funding to deliver these critical customer investments and enable the Company to do so at the lowest possible financing cost on their behalf.

### iv. Staff Fails to Consider the Average Equity Ratios of Peer Group Companies

**Q. How does Mr. Megginson's recommended 50.00% equity ratio compare to equity ratios authorized by other commissions?**

A. Mr. Megginson's recommended 50.00% equity ratio is significantly lower than equity ratios authorized by other commissions. I researched all rate case decisions from 2020

through September 2024 of peer companies and determined the authorized or approved equity ratio for each. This is reflected on Exhibit A-32 (MRB-10). The average authorized equity ratio for the peer group was 54.05%, 405 basis points higher than the 50.00% proposed by Mr. Megginson for Consumers Energy in this case. Despite this higher peer average, I am proposing a ratio of 50.75%, which balances the higher peer average with capital investment plans, credit metrics, customer rate impacts, and the guidance of this Commission, and which continues to support affordable utility infrastructure financing for the state of Michigan.

**Q. Are the equity ratios reflected on Exhibit A-32 (MRB-10) based on historical financial data or commission-authorized equity ratios?**

A. The equity ratios were taken directly from commission orders and public filings and represent actual regulatory equity ratios authorized or approved by the various commissions across the country, as specifically requested by the Commission on page 218 of its Order in Case No. U-20963. It is clear from this analysis that, on average, regulatory commissions of the Company's peer group are granting equity ratios that are much higher than the 50.75% requested by the Company in the current case, and higher still than the 50.00% equity ratio chosen by Mr. Megginson.

**Q. Did Mr. Megginson perform an analysis of the national average peer company authorized ROEs consistent with previous rate cases?**

A. Yes. Staff considered average gas utility authorized ROE decisions across the U.S. to support its ROE recommendation for the Company in this case.

**Q. Did Mr. Megginson also perform an analysis of average peer company authorized equity ratios?**

A. Yes. On page 2 of his Exhibit S-4, Schedule D-5, Mr. Megginson calculated an average authorized equity ratio of 53.62%. This is 362 basis points higher than Mr. Megginson's recommended equity ratio in this case of 50.00% and 287 basis points higher than the Company's recommended equity ratio in this case of 50.75%.

**Q. Is Mr. Megginson's peer equity ratio analysis a valid basis for purposes of authorizing a permanent equity ratio?**

A. No. According to Mr. Megginson's exhibit, the source of the equity ratio data is S&P Global Market Intelligence. S&P Global Market Intelligence tracks the authorized equity ratio as a percentage of total capitalization. Total capitalization can be higher (thereby under-reporting an equally comparable equity ratio) because, in addition to permanent capital components, items such as short-term debt, deferred taxes, and customer deposits can be included. For example, as reflected on Exhibit A-14 (MRB-1), the Company's 50.75% permanent equity ratio in this instant case translates to only 42.58% on a total capitalization basis that would be reported in Staff's referenced database, which is a difference of 817 basis points. The Company's equity ratio, which is based on a percentage of permanent capital, should only be compared to equity ratios of peer utilities based on percentage of permanent capital in order for the comparison to be at all meaningful. The actual commission-authorized equity ratios provide the required data for a comparable analysis and were relied upon in my analysis shown in Exhibit A-32 (MRB-10) which shows the average equity ratio for the peer group utilizing this method to be 54.05%.

**Q. Did Mr. Megginson consider his calculation of peer average authorized equity ratios in determining his recommended equity ratio for the Company in this case consistent with his consideration of peer averages to support his ROE recommendation?**

A. No, his recommended equity ratio for the Company in this case was inconsistent with even his own substandard peer equity ratio analysis. According to both the Company's calculations as well as Staff's own analysis, Mr. Megginson's recommended equity ratio of 50.00% is drastically understated.

**Q. Are there any other reasons why it is appropriate to consider peer company equity ratio averages and trends in determining the appropriate equity ratio for the Company in this case?**

A. Yes. In its Order in Case No. U-20963, the Commission cited Staff's average ROE analysis as one of the factors considered in determining the Company's approved ROE. In addition, in Case No. U-21585, the Administrative Law Judge ("ALJ") also considered average authorized ROEs in determining the appropriate ROE for the Company. In its Order, the Commission found that the ALJ appropriately considered the record evidence, weighing the vast testimony, methodologies and proposed ROEs on the record. It is apparent that the Commission considers peer averages an important piece of evidence to inform the ratemaking process. To be consistent with that philosophy, it is appropriate to consider peer company equity ratio averages and trends in determining the equity ratio for the Company in this case.

**v. Summary**

**Q. Please summarize your rebuttal testimony to Staff witness Megginson's recommendation of an equity ratio of 50.00% for the test year in this case.**

A. In my rebuttal testimony, I have shown that Mr. Megginson's position on equity ratio is largely not evidence based and that the evidence which he does provide is unsound and should not be relied upon. Further, I have shown that, based on the recent dramatic increase in risk and volatility, a deviation from a balance structure is justified at this time. I have also shown that Staff's recommended equity ratio for the test year in this case is below what is considered supportive of the Company's credit quality and also significantly lower than the average equity ratio of peer group companies. For these reasons, Staff's recommended equity ratio of 50.00% for the test year in this case should be rejected.

## C. Rebuttal of Staff's Recommendation Regarding the Cost of Long-Term Debt

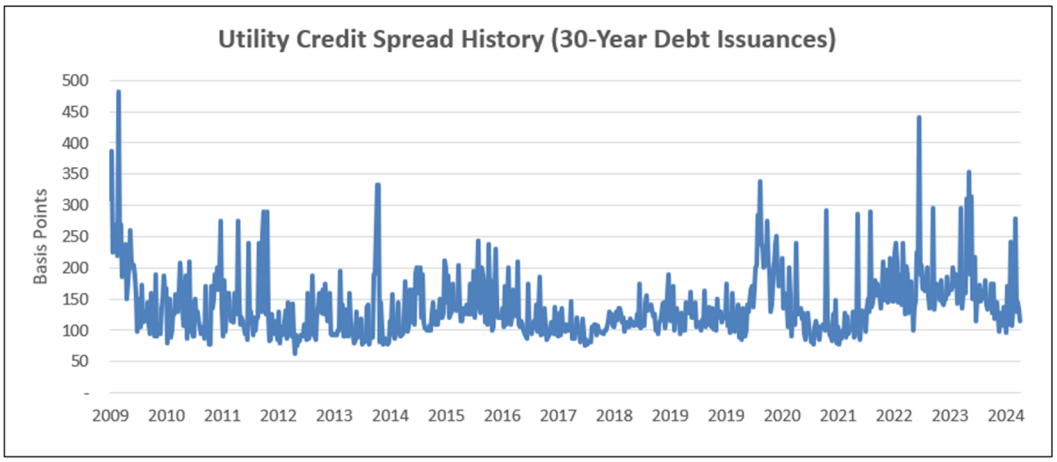
**Q. Please explain your disagreement with Staff's cost of long-term debt recommendation of 4.33% as reflected on Mr. Megginson's Exhibit S-4, Schedule D-1.**

A. Mr. Megginson's assumed credit spread (added to the U.S. Treasury rate to calculate the total projected interest rate on the new debt issuances) is also unreasonably low.

**Q. Mr. Megginson uses the credit spreads on the Company's recent long-term debt issuances as a basis for projecting a 100 basis point credit spread on the Company's forecasted debt issuances through the test year in this case. Is this a reasonable approach?**

A. No. As explained on page 33 of my direct testimony, credit spreads for long-term debt issuances are very difficult to predict and can be quite volatile in short periods of time. This is because credit spreads are based on a number of factors, most notably the

Company's credit rating and the market conditions at the time of the debt issuance, including both same-day and short-term supply/demand dynamics. The volatility of credit spreads is illustrated on the following chart:




Mr. Megginson's 100 basis point credit spread is also quite obviously at the very low end of the historical spreads for 30-year debt issuances, as evidenced in the chart above. In addition, as shown in Staff's discovery response included as Exhibit A-115 (MRB-18), Mr. Megginson includes credit spreads on the Company's recent long-term debt issuances which are not 30-year maturities as a basis for projecting the credit spreads on forecasted debt issuances that are assumed to be 30-year maturities. Credit spreads on debt issuances vary based on the tenure or maturity of the debt issuance (for example, a 10-year bond versus a 30-year bond). For these reasons, Mr. Megginson's methodology for estimating the credit spread on the Company's projected long-term debt issuances is faulty and should be rejected by the Commission. Alternatively, the Company has provided a very sound approach to projecting credit spreads. Given the lack of a reliable source for projected credit spreads, I applied the calculated average credit spread on a 30-year debt issuance for investment grade utilities from the last 15 years which was approximately 136 basis points.

Since credit spreads can be volatile in the short-term, a longer-term historical average is a rational approach with regard to credit spreads.

### D. Staff's Recommendation Regarding the Projected Working Capital Cash Balance

**Q. Does Staff recommend a working capital cash balance for the test year in this case that is lower than the Company's projection?**

A. Yes. On page 5 of Staff witness Hecht's direct testimony, he recommends an adjustment to reduce the Company's projected cash balance by $5,263,000. Mr. Hecht states that the Company used incorrect data to calculate the cash balance in its original filing and that the balance should be $23,130,000 rather than $28,393,000.

**Q. Does the Company object to Staff's adjustment to the working capital cash balance?**

A. No. The Company's methodology of projecting the cash balance of 1% of test year revenues is not in dispute, but rather the correct test year revenues that the 1% should be applied to. The Company agrees that the 1% was applied to the incorrect revenues amount in the Company's original filing and therefore accepts Staff's cash working capital adjustment.

## II. REBUTTAL OF AG WITNESS COPPOLA

### A. Overview of Areas of Disagreement Addressed

**Q. What aspects of AG witness Coppola's recommendations are you rebutting?**

A. I am rebutting Mr. Coppola's recommendation regarding the common equity ratio. I am also rebutting Mr. Coppola's recommendation regarding the Company's working capital cash balance.

**Q. Are there any other aspects of Mr. Coppola's recommended capital structure that the Company disagrees with?**

A. Yes. Consumers Energy does not agree with Mr. Coppola's recommended ROE of 9.75%. This issue, however, is addressed in the rebuttal testimony of Company witness Bulkley.

## B. Rebuttal to Mr. Coppola's Recommendation Regarding the Common Equity Ratio

**Q. On page 110 of his direct testimony, Mr. Coppola references the Commission's Orders in Case No. U-21585 and Case No. U-21389, the Company's two most recent fully-contested cases, in which both orders authorized a balanced equity ratio. Mr. Coppola then concludes that the Company's capital structure in the current case should "similarly mirror" the common equity ratio last approved by the Commission. Do you agree with this conclusion?**

A. No. The appropriate equity ratio for the Company should be based on the facts and circumstances presented in the current case and not predetermined based on prior Commission orders. Refer to my earlier rebuttal testimony to Staff witness Megginson (ii. Staff Fails to Consider New Circumstances That Justify a Deviation From a Balanced Capital Structure). While the Commission authorized a balanced capital structure in the cases referenced by Mr. Coppola, the Commission has also made clear that there should be flexibility in its assessment, allowing for a deviation from a balanced capital structure when circumstances warrant it. It is clear from these orders that the Commission does not consider a balanced capital structure a mandate to be followed blindly, but rather as a basis from which a deviation may be justified upon consideration of the evidence and circumstances of each rate case.

**Q. Has the Company presented evidence in this case that an equity ratio of 50.75%, slightly above a balanced capital structure, is warranted?**

A. Yes. Refer to pages 10 through 23 of my direct testimony in which I outline reasons why an equity ratio of 50.75% and an ROE of 10.25% as proposed by the Company in this case are well-measured for both the Company and its customers, while still mindful of the Commission's previous orders. Also refer to my earlier rebuttal testimony to Staff witness Megginson. There have been new circumstances that gives credence to the Company's contention that a deviation from a balanced capital structure is justified at this time including extreme financial market volatility, supply chain impacts, inflationary pressures, and increased fears of a U.S. recession in 2025. As provided for in previous Commission orders, an equity ratio of 50.75% (slightly above a balanced capital structure) is warranted given the facts and circumstances present in the current case.

**Q. On page 113 of his direct testimony, Mr. Coppola references recent credit opinions from Moody's and S&P, noting that the Company's FFO-to-Debt ratio in recent years for both rating agencies was higher than the threshold that could lead to a further downgrade if the Company fell below. For S&P, Mr. Coppola concludes that "these coverage ratios are not indicative of any concerns about a possible debt rating downgrade." Is the Company's FFO-to-Debt ratio in recent years evidence that the Company is not at risk for further credit rating downgrade?**

A. No. First, as explained on pages 15 to 16 of my direct testimony and earlier in my rebuttal testimony to Staff witness Megginson, the Company's FFO-to-Debt ratio as calculated by rating agencies has been trending down in recent years – a decrease of 410 basis points for S&P and a decrease of 350 basis points for Moody's. This sizable amount of credit ratio

deterioration, which is brushed off by Mr. Coppola, should be troubling to the Commission. Second, while the Company's FFO-to-Debt ratios in previous years were higher than the downgrade threshold, the results cover a time when the Company's equity ratio was significantly higher than Mr. Coppola recommends for the Company in this case - 52.7% in 2021 and 53.2% in 2022. Therefore, Mr. Coppola's statement that there is no concern of downgrade should be discounted by the Commission.

**Q. On page 114 of his direct testimony, Mr. Coppola references the increase in the Company's net income in 2024. Mr. Coppola concludes that this will have a positive impact on the Company's credit metrics. Do you agree with this conclusion?**

A. No. Refer to my earlier rebuttal testimony to Staff witness Megginson on this issue. Higher net income is not necessarily indicative of higher credit metrics or credit quality. Since net income can be skewed by non-cash transactions, rating agencies instead look to the Company's cash flow metrics, including its FFO-to-Debt ratio. Rating agencies also look at the strength of the Company's balance sheet, including its equity ratio. Finally, rating agencies evaluate the supportiveness of the Company's regulatory environment, including the authorized ROE and equity ratio. These measures are a better indicator of the Company's credit quality and credit rating. Based on rating agencies' criteria, the weighted rate of return authorized in this case, and not net income, will be a significant factor in determining the Company's credit quality.

**Q. On pages 114 to 115 of his direct testimony, Mr. Coppola refers to the Company's direct testimony which showed that the Company's FFO-to-Debt ratio as calculated by S&P and Moody's has been trending down in recent years. Mr. Coppola dismisses these sharp declines as "temporary" and the result of "unusual and short-term issues." Do you agree with this assessment?**

A. No. Mr. Coppola describes events such as unfavorable weather, storm activities, and higher gas prices as the main cause for the Company's decline in credit metrics in recent years. First of all, Mr. Coppola omits that, as explained on pages 15 to 16 of my direct testimony, the decline in the Company's FFO-to-Debt ratio has coincided with recent rate cases which have resulted in a sharp decline in rate of return (ROE multiplied by equity ratio) having a directly negative result on credit metrics, both historic and future. Secondly, there is no guarantee that these issues that Mr. Coppola describes as "temporary" such as storms, will not persist in future years. For example, from the end of March 2025 through the beginning of April 2025, the Company's service territory was hit with the worst ice storm in northern Michigan in over 100 years, as confirmed by the National Weather Service. At the same time, the lower peninsula of Michigan was hit by thunderstorm systems strong enough to produce 13 confirmed tornados. The Company estimates this combined storm event will result in approximately $96 million in operating and maintenance ("O&M") expense, significantly higher than any other Consumers Energy storm event O&M amount in at least the last 20 years. This cost of this storm will have a significant detrimental impact on the Company's credit metrics in 2025 and 2026. In fact, Mr. Coppola's testimony highlighting the negative impact of these events demonstrates the

importance of maintaining strong credit metrics in preparation for such events and not managing the Company toward the lower margins.

**Q. On pages 115 to 116 of his direct testimony and his Exhibit AG-49, Mr. Coppola references his calculation of the Moody's FFO-to-Debt ratio for the Company for 2023 assuming a 9.75% ROE and a 50.0% equity ratio. According to Mr. Coppola's calculations, the Company's FFO-to-Debt ratio would have been 20.1%, or 100 basis points higher in 2023 with these assumptions. Do you agree with Mr. Coppola's calculations?**

A. No. In his calculations, Mr. Coppola mixes the Company's authorized ROE with the Company's earned ROE, greatly distorting the pro forma FFO-to-Debt impacts. First, Mr. Coppola calculates the Company's actual earned ROE of 8.25% in 2023. Next, Mr. Coppola makes two assumptions: (1) that the Company's authorized ROE was 15 basis points lower in 2023 (9.75% versus 9.90%); and (2) that the Company actually earned that authorized ROE in 2023 (9.75% versus 8.25%). Mr. Coppola's second assumption is false in that he is attempting to show the FFO-to-Debt ratio for the Company for 2023 only assuming an authorized ROE of 9.75% and an equity ratio of 50.0%. In essence, Mr. Coppola is suggesting that if the Company's authorized ROE in 2023 was 15 basis points lower (9.75% versus 9.90%), the Company's FFO would have been $155 million higher. This lacks logical sense and results in a pro-forma FFO-to-Debt ratio that is significantly overstated. Therefore, Mr. Coppola's pro forma FFO-to-Debt analysis for Moody's in 2023 is faulty and should therefore be rejected by the Commission.

**Q. On pages 117 to 118 of his direct testimony, Mr. Coppola references recent credit opinions from S&P and Moody's which indicate a stable outlook for the Company. Is this evidence that the Company is not at risk for further credit rating downgrade?**

A. No. In assessing credit quality, rating agencies must make certain assumptions with respect to the Company's outlook, including future financial results and regulatory outcomes. However, the assumption of a stable outlook should not be interpreted as assurance that these assumptions will ultimately materialize, with no risk of a credit rating downgrade. For example, Mr. Coppola highlights the rating agencies' assumption that the Company will continue to operate in a constructive regulatory environment. However, the Company's credit rating is continuously evaluated, and the authorized ROE and equity ratio in this case will be a key component of future evaluations. As shown on page 15 of my direct testimony, the results from the Company's most recent rate cases demonstrate a sharp decline in authorized weighted rate of return (ROE times equity ratio) following a long period of stability. The persistent decline in the Company's authorized weighted rate of return since 2020 could be seen as a material deterioration in the credit supportiveness of the Michigan regulatory environment. In addition, refer to my earlier rebuttal testimony to Staff witness Megginson. In August 2024, S&P lowered its ranking of Michigan's regulatory environment from "Above Average" to "Average" referencing less favorable authorized ROEs and a "tightening in the regulatory climate." In updating its regulatory rankings for U.S. utilities in May 2023, UBS also moved Michigan down a level from Tier 1 to Tier 2. In describing the negative change, UBS specifically mentioned authorized ROEs as well as a lowering of their "subjective factor" for the Michigan regulatory jurisdiction, which is based on UBS's "knowledge of current commission actions." It is

apparent that analysts have taken note of the recent trend in the Company's regulatory outcomes with regard to capital structure. A continuation or, even worse, a further degradation of the authorized equity ratio and ROE puts the Company at risk of dropping further in its regulatory environment rankings which could negatively impact the Company's credit quality and credit rating.

**Q. On pages 118 to 119 of his direct testimony, Mr. Coppola references the Company's Exhibit A-107 (MRB-16), a report by S&P "Rising Risks: Outlook for North American Investor-Owned Regulated Utilities Weakens." Mr. Coppola argues that this report should be dismissed because it is "generic" and not "directly applicable to Consumers Energy." Do you agree with Mr. Coppola's assessment of this report?**

A. No. While certain aspects of this report are not applicable to Consumers Energy, there are also key portions that are directly relevant to the appropriate equity ratio for the Company in this case. For example, in the report S&P cites "headwinds to credit quality" including increased cash flow deficits that are funded to a higher extent with debt versus equity. This concern is relevant in the current case given that the Company's authorized equity ratio has decreased 205 basis points from 2019 to present, weakening credit quality and putting the Company's credit rating at risk. S&P also notes utilities as having "strained financial cushion," defined as an FFO-to-Debt ratio less than 100 basis points above a company's downgrade threshold. This is also relevant to the Company in this case given that, as explained in my direct testimony and earlier in my rebuttal testimony, the Company's FFO-to-Debt ratio as calculated by S&P and Moody's has been trending down in recent years, moving closer to the downgrade thresholds for the Company. Finally, the report cites multiple additional credit headwinds that all utilities (including Consumers Energy) are

facing including higher interest rates, a narrowing spread between U.S. Treasuries and authorized ROE's, and elevated inflation rates. Therefore, Mr. Coppola's assertion that the Commission should dismiss this relevant industry report should be rejected.

**Q. On page 119 of his direct testimony, Mr. Coppola references the Company's testimony on the credit metric impact of potential new tax legislation. Mr. Coppola states that this issue should not be considered as a factor in determining the Company's ROE rate and equity ratio in this case. Do you agree with this assertion?**

A. No. As explained on pages 16 to 17 of my direct testimony, the new tax legislation, if enacted, would have direct and significant impacts on the Company's cash flow, resulting in a weakening of the Company's financial metrics. These potentially credit harmful legislative actions were highlighted in S&P's January 2025 report on North American regulated utilities which stated that "tax legislation could weaken financial measures." Refer to Exhibit A-114 (MRB-17). With this potential new tax legislation looming during the test year of this case, it is especially important for the Commission to authorize an ROE and equity layer that will be supportive of the Company's credit quality. The authorized ROE and equity ratio are integral components of the Company's financial credit metrics and will be a key factor in combating the negative impacts of this potential tax legislation.

**Q. Beginning on page 120 of his direct testimony, Mr. Coppola states that "common equity capital infusions into Consumers Energy by the parent company are being funded to some extent by long term debt." He cites "financial transactions" between Consumers Energy and CMS Energy. Do you agree with these statements?**

A. No. Mr. Coppola's assertion that equity investments into the Company from Consumers Energy's parent company, CMS Energy, are the result of CMS Energy borrowing debt and

investing the proceeds into the Company is inaccurate and unsupported. The timing and amounts of long-term debt and equity issued by CMS Energy have no bearing on the timing and amount of equity infusions made into Consumers Energy. Equity infusions are determined after considering the capital spending and financing needs of Consumers Energy. The goals of the parent company include maintaining a strong and healthy utility, capable of serving the needs of its customers. This commitment is reflected in the equity infusions from the parent company to Consumers Energy over the last several years and the resulting actual equity ratio.

**Q. On page 122 of his direct testimony, Mr. Coppola provides an analysis of the capital structure of CMS Energy and Consumers Energy from 2010 to 2024, attempting to link changes in long-term debt and equity between the two companies. Does this analysis have any merit in the current case?**

A. No. As explained above, the timing and amounts of long-term debt and equity issued by CMS Energy have no bearing on the timing and amount of equity infusions made into Consumers Energy. Also, in Case No. U-18124 the AG made this same argument that Consumers Energy's equity balance is, at least in part, funded by long-term debt from its parent company. In its July 31, 2017 Order in Case No. U-18124, the Commission adopted the findings and recommendations of the ALJ, who determined this argument from the AG "has been considered and rejected by the Commission." Mr. Coppola's analysis has been found to have no merit in the past and should again be rejected.

**Q. On page 124 of his direct testimony, Mr. Coppola's argument for setting a 50.00% equity ratio in this case is that the common equity ratio of his peer group was 47.3% in 2024, as shown on his Exhibit AG-44. Is this an appropriate comparison to the projected common equity ratio in this case?**

A. No. The average equity ratio calculation for the proxy group on Mr. Coppola's Exhibit AG-44 uses the equity ratio at the parent holding company level and is, thus, a misleading and inappropriate comparison. As the Company has repeatedly explained in response to this exact same argument by the AG over the years, ratios at the parent holding company level may be distorted by other, non-regulated balance sheet items and provides a completely inappropriate point of comparison. Mr. Coppola continues to avoid addressing this discrepancy. Perhaps the 270 basis point differential between the results of his analysis on Exhibit AG-44 and his own recommendation points to Mr. Coppola's recognition that the analysis does not provide a relevant comparison. In addition, Mr. Coppola's analysis is further skewed because the sources for Mr. Coppola's debt and equity balances are Securities and Exchange Commission reported financial statements, which are prepared under Generally Accepted Accounting Principles ("GAAP"). There are major differences in how components of the capital structure are classified on a ratemaking basis and on a financial basis. These differences could easily further distort the equity ratios calculated on Mr. Coppola's Exhibit AG-44.

**Q. Is Mr. Coppola's average peer group equity ratio analysis in line with the Commission's stated expectations?**

A. No, the Company is the only party in this case that has provided peer equity ratio analysis that is in line with the Commission's stated expectations. In its Order in Case No. U-20963,

the Commission stated that "regulatory and financial data should not be combined" with such an analysis. Further, the Commission deemed in its Order in Case No. U-20963 that such an analysis is invalid assuming one "could not verify that its data contained equity ratios set by a regulatory commission in a rate case." In his analysis of a proper equity ratio for the Company, Mr. Coppola ignores this Commission's ask by consistently utilizing equity ratios based, in part, on financial, and not regulatory, data. He consistently utilizes equity ratios that do not arise out of Commission orders, and he further fails to explain the basis or rationale for doing so. As a result, the AG's equity ratio analysis should be rejected as outside the methodology required by the Commission.

**Q. If equity ratios on a financial basis are not considered relevant, what is the more appropriate comparison of average utility equity ratios?**

A. It is clear from the Commission's Order in Case No. U-20963 that actual commission-authorized equity ratios is the preferred data source for an average equity ratio analysis. I refer to my Exhibit A-32 (MRB-10) in which I researched all rate case decisions from 2020 through September 2024 of peer regulated companies and determined the authorized or approved equity ratio for each. The equity ratios used for comparison purposes were taken from commission orders and public filings and represent actual regulatory peer equity ratios authorized or approved by different commissions across the country. The average equity ratio for the peer group was 54.05%. This is significantly higher than the equity ratio recommended for Consumers Energy's capital structure in my rebuttal testimony and is also 405 basis points higher than the equity ratio Mr. Coppola recommends for the Company in this case. Despite this higher peer average, I am proposing a ratio of 50.75%, which balances the higher peer average with capital

investment plans, credit metrics, customer rate impacts, and the guidance of this Commission, and which continues to support affordable utility infrastructure financing for the state of Michigan.

**Q. On pages 125 through 127 of his direct testimony, Mr. Coppola attempts to discredit the Company's calculation of the peer group average commission-authorized equity ratios reflected on Exhibit A-32 (MRB-10). Do these arguments have merit?**

A. No. The Company adhered to an established selection criteria outlined on Exhibit A-32 (MRB-10). Mr. Coppola's claims are false and divert attention away from his own lack of meaningful comparisons, meaningful criteria, and meaningful analyses of various utilities, commission decisions, and basis for equity ratios. As explained in my direct testimony and earlier in my rebuttal testimony, the Company's data source is responsive to previous Commission orders and serves as a valid benchmark for the appropriate equity ratio for the Company in this case. As I will show in my following rebuttal testimony, Mr. Coppola's "problems" with Exhibit A-32 (MRB-10) are completely baseless and are an attempt to devalue the compelling evidence put forth by the Company that average peer company equity ratios are significantly higher than what Mr. Coppola proposes for the Company in this case.

**Q. On page 125 of his direct testimony, Mr. Coppola notes that three proxy group companies listed on Exhibit A-32 (MRB-10) are not included as part of the Company's ROE proxy group in the current case. Does this in any way discredit the Company's peer authorized equity ratio analysis?**

A. No. As explained earlier in my rebuttal testimony, the Company adhered to an established selection criteria outlined on Exhibit A-32 (MRB-10) which included a scope of all

regulated subsidiaries of the Company's ROE proxy group in Case No. U-21490, the Company's most recent gas rate case before the current case. The purpose of the Company's Exhibit A-32 (MRB-10) is to provide a benchmark of equity ratios recently authorized by other commissions across the country. The fact that three of the proxy group companies included in the Company's analysis were included in the ROE proxy group in Case No. U-21490 and not the current case does not discredit or minimize the value of the analysis, as it is still a representative sample of recent rate case decisions.

**Q. On page 125 of his direct testimony, Mr. Coppola claims that the average peer equity ratio calculated on Exhibit A-32 (MRB-10) is overstated due to several of the companies included in the exhibit using short-term debt as a form of permanent financing which, when considered permanent (long-term) debt in the company's capital structure, results in a lower equity ratio. Are Mr. Coppola's claims valid?**

A. No. First, as shown on Exhibit A-14 (MRB-1), Schedule D-1, the Company's equity ratio of 50.75% excludes short-term debt. Therefore, in order to produce a comparable and relevant analysis, the peer company authorized equity ratios also exclude short-term debt (as well as other capital structure components such as deferred taxes). Second, Mr. Coppola makes the assumption that companies employ short-term debt as a permanent layer of financing. This is not always the case, a prime example being Consumers Energy which has short-term debt as a component of its capital structure but is not considered "permanent" capital. In a discovery response, the AG explains that the claim of companies in the exhibit using short-term debt as a form of permanent financing was not based on the companies included in the exhibit, but rather for four companies at the parent holding company level, based on Securities and Exchange Commission reported financial

statements. Exhibit A-118 (MRB-21). This invalidates Mr. Coppola's argument entirely. The average peer equity ratio on Exhibit A32 (MRB-10) is appropriately calculated at the regulated subsidiary level based on state commissions' rate case dockets. This is comparable to Consumers Energy's projected capital structure considered in the current case. Conversely, debt held outside of these companies, at the parent holding company level or otherwise, is completely irrelevant to this analysis. As an example, short-term debt balances held by CMS Energy, Consumers Energy's parent company, is irrelevant to the appropriate capital structure for the Company in the current rate case proceeding. Even if the short-term debt of his four proxy group companies is representative of their regulated subsidiaries, as Mr. Coppola argues, he does not provide evidence showing how this impacts the equity ratios of the regulated subsidiaries reflected on the Company's Exhibit A-32 (MRB-10). As with his calculation of the average peer group equity ratio, Mr. Coppola again attempts to introduce parent holding company data in an attempt to obfuscate the Company's sound analysis. Mr. Coppola's comparisons are inappropriate and should be rejected by the Commission.

**Q. On page 126 of his direct testimony, Mr. Coppola claims that the Company's peer average authorized equity ratio reflected on Exhibit A-32 (MRB-10) is overstated as a result of the inclusion of smaller companies which "tend to have higher equity ratios to sustain them during potential volatility in their business, which larger utilities can better manage." Do you agree with this conclusion?**

A. No. Mr. Coppola presents no evidence showing a correlation between a company's size and its authorized equity ratio. Refer to Exhibit A-118 (MRB-21). When asked in discovery for analyses, studies, or reports supporting this statement, Mr. Coppola indicated

that he "relied on his knowledge and experience." In his discovery response 3-CE-AG-6 Attach 1 (see Exhibit A-118 (MRB-21), Mr. Coppola also included an excerpt from Dr. Robert Morin's book New Regulatory Finance which discusses the relationship between company size and investment risk and return. This is a separate issue from the impact of a company's size on its authorized equity ratio and does not support Mr. Coppola's claim. Therefore, Mr. Coppola's assumption that the inclusion of certain "smaller" companies results in an overstatement of the peer average is unsupported and should be rejected. In addition, Exhibit A-32 (MRB-10) is intended to be an informative survey of all commission-authorized equity ratios for utilities across the country and not filtered to adjust for or exclude companies with certain characteristics (customer count, rate base size, etc.). Finally, Mr. Coppola again presents a criticism of the Company's peer equity ratio analysis without offering an alternative analysis that he believes to be more representative of commission-authorized equity ratios. Mr. Coppola performs no analysis at all, but rather simply relies on the average equity ratio calculation for the parent holding companies of his proxy group of 47.3%. As explained earlier in my rebuttal testimony, this approach is flawed and should not be relied upon in this case.

### C. Rebuttal to Mr. Coppola's Recommendation Regarding the Working Capital Cash Balance

**Q. On page 103 of his direct testimony, Mr. Coppola references the Company's approach to projecting the cash balance for the test year in this case equal to approximately 1% of test year revenues. Mr. Coppola argues that, if the Company were to instead base its projection on current revenues, the test year cash balance would yield a lower result. Is using current revenues appropriate in projecting the test year cash balance in this case?**

A. No. The Company uses a forward looking test year in this case, projecting an adequate level of cash for the test year ending October 2026. Therefore, basing the projected cash balance on current or historical revenues would not be appropriate.

**Q. On page 103 of his direct testimony, Mr. Coppola attempts to discredit the Company's approach to projecting the cash balance for the test year in this case, stating that "cash on hand is not used to pay for revenues. It is used to pay operating expenses, capital expenditures and dividends to the parent company." Is this a valid argument against the Company's 1% of test year revenues rule of thumb?**

A. No. The Company's cash estimation method is not intended to project all future cash outflows in order to determine a required cash balance. Rather, the 1% of test year revenues is a simple, efficient, and easily calculated benchmark that is useful in estimating a reasonable level of cash for the Company. As the size of the Company grows along with its associated operating revenues, the appropriate level of cash on hand also grows. Thus, the various uses of the Company's cash is not a valid argument against the Company's cash projection methodology.

**Q. On page 103 of his direct testimony, Mr. Coppola again attempts to discredit the Company's approach to projecting the cash balance in this case by stating that "utilities maintain different levels of cash on hand during different months of the year depending on their seasonal needs for cash to pay for gas purchases, fund gas inventories and pay for operating expenses and construction costs." Does the seasonality of cash expenditures invalidate the Company's 1% of test year revenues rule of thumb?**

A. No. Refer to pages 27 to 29 of my direct testimony which describes the Company's liquidity and financing strategy. Due to the seasonal nature of utility cash inflows and outflows, the Company generally holds more cash in the spring and summer months and relies on short-term borrowing in the fall and winter months. However, the Company is not projecting the cash balance for a point in time, but rather an average cash balance for the entire test year in this case. Therefore, the seasonal nature of cash outflows is already factored into the Company's position.

**Q. On pages 103 and 104 of his direct testimony, Mr. Coppola refers to the Company's cash projection methodology of 1% of test year revenues as being based on "an analysis it performed a few years ago for a group of utilities." Mr. Coppola argues that this analysis was based on cash balances presented in GAAP financial statements and is therefore inappropriate. Is this argument valid?**

A. No. Refer to Exhibit A-93 (AJD-13) in Case No. U-17990, the Company's 2016 electric rate case. In this exhibit, the Company performed an analysis of the average cash balance as a percentage of operating revenue for the Company's peer group at the regulated subsidiary level. This analysis resulted in a peer average of 1.9%, showing that the

projected test year cash balance in that case was reasonable and appropriate compared to other utilities. While the peer companies' cash balances reflected in that analysis may or may not have included temporary cash investments, the peer average was 90 basis points higher than projected for the Company in the current case. This is another example of Mr. Coppola attempting to muddle the valid analysis that the Company has performed.

**Q. On page 104 of his direct testimony, Mr. Coppola argues that the Company's cash analysis from Exhibit A-93 (AJD-13) in Case No. U-17990 was inappropriate because it used data on a GAAP financial basis. Does Mr. Coppola perform an analysis based on GAAP financial data in his testimony and exhibits?**

A. Yes. Refer to my earlier rebuttal testimony to Mr. Coppola's peer group equity ratio calculation of 47.3%. Mr. Coppola's analysis is skewed because the sources for Mr. Coppola's debt and equity balances are Securities and Exchange Commission reported financial statements, which are prepared under GAAP. There are major differences in how components of the capital structure are classified on a ratemaking basis and on a financial basis. These differences could easily distort the equity ratios calculated in Mr. Coppola's peer group equity ratio analysis. Following Mr. Coppola's own reasoning on page 104 of his direct testimony, his peer group equity ratio calculation of 47.3% is misleading and should not be used in determining the appropriate equity ratio for the Company in this case.

**Q. On page 104 of his direct testimony, Mr. Coppola again attempts to discredit the Company's approach to projecting the cash balance by stating that "every utility has different short-term borrowing facilities and different practices as to how they use or do not use them and may retain more or less cash on hand depending on those circumstances." Does the fact that different utilities have different practices with respect to short-term borrowing and cash on hand invalidate the Company's 1% of test year revenues rule of thumb?**

A. No. Refer to the description of the Company's liquidity and financing strategy on pages 27 to 29 of my direct testimony. The Company's 1% of test year revenues rule of thumb is not intended to match other utilities' liquidity and financing practices. The Company acknowledges that different utilities hold different levels of cash and short-term debt based on their individual preferences and liquidity risk tolerance levels. The Company projects its cash balance at a level that is reasonable and appropriate for Consumers Energy, which equates to approximately 1% of test year revenues.

**Q. On page 105 of his direct testimony, Mr. Coppola recommends that the level of cash in working capital in this case be equal to the average of the actual cash balances for 2022, 2023, and 2024. This equates to a balance of $12.3 million, $16.1 million lower than forecasted by the Company. Do you agree with this proposal?**

A. No. Using the average of actual cash balances from 2022, 2023, and 2024 results in a cash balance much lower than is normally expected and required for the Company in the test year of this case. The spike in natural gas prices in 2022 resulted in cash balances that were lower than what is normally expected and required for the Company and are therefore not representative of typical cash balances historically or in the test year of this case. In

addition, the Company experienced unfavorable weather in 2023, as well as storm restoration activity well beyond the five-year historical average. Both of these conditions negatively affected the Company's operating cash flows and cash balance. It is inconsistent that Mr. Coppola cites those "temporary" issues when discussing the Company's credit metrics from that period of time but ignores them for this argument. Since the Company's cash balance was abnormally low in 2022 and 2023, the average from those years should not be used in projecting the cash balance in this case. Also refer to my earlier rebuttal testimony in which I explain why the use of historical cash balances is not appropriate. Instead, the projected cash balance for the test year in this case should equate to approximately 1% of test year gas revenues, which results in a cash balance of $23.13 million which is reflective of normal levels of cash on hand.

**Q. What are the risks associated with the Company maintaining an unreasonably low cash balance of $12.3 million, or 0.5% of test year revenues, as Mr. Coppola recommends?**

A. Maintaining an insufficient cash balance would force the Company to rely more heavily on its short-term borrowing facilities. Short-term financing markets can be volatile and, at times, access to those markets completely disappear, as was witnessed during the 2008 credit crisis, again in March 2020 as a result of pandemic-related market fear, and again in March 2023 during the banking industry turmoil. Based on the experience and judgment of the Company's Treasury Department, as well as members of the Financial Planning and Analysis Department, the Company does not pursue a strategy that maintains a permanent balance of short-term debt. However, the Company does fund seasonal fluctuations in its working capital with short-term debt. The Company's projected cash balance for the test

year in this case is reflective of normal levels of cash that are expected and necessary for the Company to manage working capital requirements and manage financial risk.

**Q. In addition to managing financial risk, what are some benefits associated with the Company maintaining a cash balance equal to approximately 1% of test year revenues as projected by the Company?**

A. In order to obtain an attractive interest rate for long-term bond financing and to minimize the refinancing risk, the Company at times issues new bonds a few months in advance of the actual maturity. Having adequate levels of cash on hand allows the Company additional flexibility in securing the lowest interest rate on its long-term debt issuances which benefits the Company and customers. In addition, given the Company's large capital expenditure program, the Company aims to maintain an overall liquidity that is sufficient to carry out not only the day-to-day operations but also have the flexibility to meet investing activities should there be a delay in accessing long-term capital from capital markets. For these reasons, the Company's projected cash balance included in working capital for the test year in this case is reasonable and is supportive of the Company's operating, investing, and financing activities.

**Q. Does the Company's cash balance impact its credit rating and credit quality?**

A. Yes. For example, S&P uses a quantitative measure in assessing liquidity in its evaluation of the Company's credit quality. With this measure, S&P looks at cash on hand and projected cash sources and uses in determining the Company's "liquidity cushion." In its ratings methodology document, S&P describes liquidity as "an important component of our financial risk assessment across the entire rating spectrum… In our view, unlike most other rating factors that we blend together in assessing an issuer's risk profile, a lack of

liquidity could precipitate the default of an otherwise healthy entity." Another rating agency, Moody's, has commented on liquidity as saying "we consider liquidity a key element of our analysis of regulated electric and gas utilities." In assessing the Company's credit quality, Moody's performs a similar analysis of the Company's liquidity cushion and flexibility as S&P, estimating the Company's ability to meet near-term cash requirements using its available sources. The third major credit rating agency, Fitch, also has a liquidity measure which is calculated as the amount of readily available cash and credit capacity to service or meet debt maturities and interest obligations. This score indicates if the Company has adequate headroom with cash on hand to cover its operating and short-term liquidity requirements. It is apparent that all three major credit rating agencies consider the level of cash on hand to be an important component of their assessment of the Company's credit quality and credit rating.

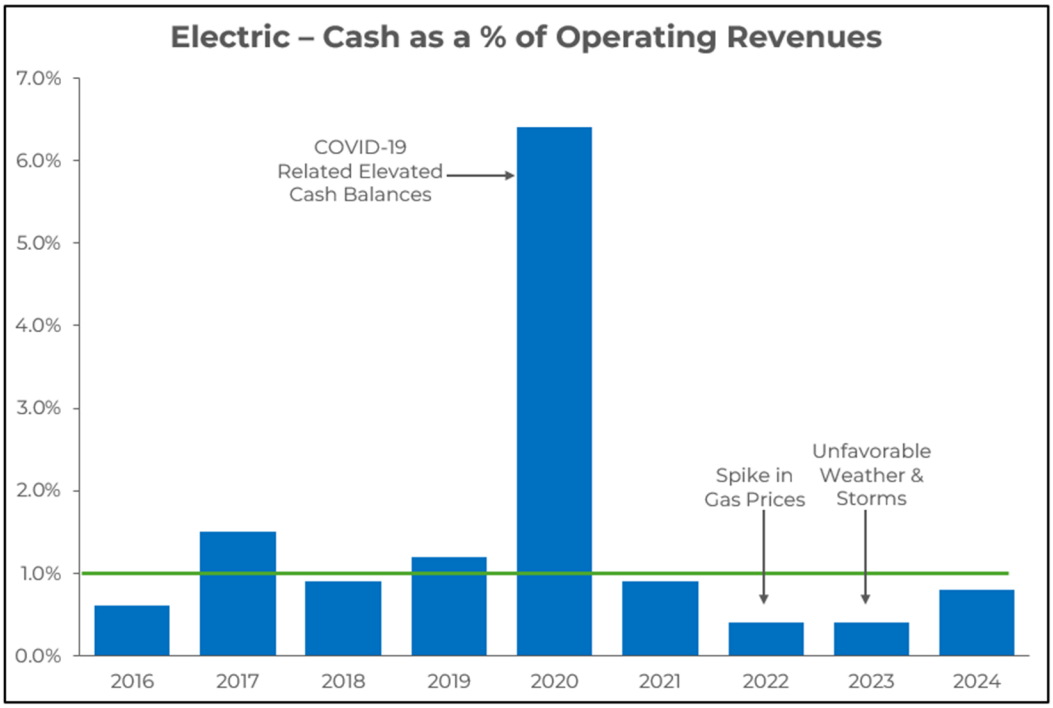
**Q. In prior rate cases, has the Company proposed an adjustment to <u>reduce</u> its projected cash balance to a more reasonable level?**

A. Yes. Refer to Case No. U-21148 and Case No. U-20963. In those cases, the historical period included several months in 2020, in which the country experienced extreme volatility, disruption, and illiquidity in the financial markets related to the COVID-19 pandemic. During this time, the Company took a proactive approach by issuing long-term debt and temporarily holding elevated cash balances. These actions limited the Company's risk of being unable to raise needed capital, strengthened the Company's liquidity, and ensured funding for the continued operations of the Company during this uncertain time. As a result of these actions, however, using the historical period that included 2020 in those cases would have resulted in a cash balance that was higher than what is normally expected

and required for the Company. As a result, in those cases the Company used cash balances from an alternative historical period that more appropriately reflected normal, lower levels of cash balances.

**Q. Has the Company shown that its actual cash balances have approximated 1% of operating revenues over the last several years?**

A. Yes. Refer to the following chart which shows a history of the Company's actual cash balances as a percentage of operating revenues from 2016 to 2024:




The chart shows that the Company's actual cash balances have approximated 1% of operating revenues with the exception of 2020, 2022, and 2023. In 2020, as described earlier in my rebuttal testimony, the Company temporarily held elevated cash balances related to the COVID-19 pandemic. In 2022 and 2023, higher gas prices and unfavorable weather and storm restoration activity negatively affected the Company's operating cash flows and cash balances. For the years in which the Company's cash balances were

unusually higher or lower than normally expected, the Company adjusted its rate case projected cash balance (higher or lower) to account for these deviations.

**Q. In conclusion, what is the appropriate cash balance for the Company for the test year in this case?**

A. As explained in my earlier rebuttal testimony, the Company accepts Staff witness Hecht's working capital adjustment to reduce the Company's projected cash balance by $5,263,000 to $23,130,000. This equates to approximately 1% of test year gas revenues and, as I have shown in my rebuttal testimony, results in a level that is needed, reasonable, and adequately minimizes the Company's financial risk.

## III. REBUTTAL OF ABATE WITNESS WALTERS

**Q. On page 6 of his direct testimony, Mr. Walters presents Table CCW-2 – Trends in State Authorized Common Equity Ratios which lists average equity ratios by year from 2013 to 2025. What trend does the data in this table reveal?**

A. As shown in Mr. Walters' Table CCW-2, the average equity ratio has increased 246 basis points from 49.79% in 2015 to 52.25% in 2024, clearly an upward trend. In fact, Mr. Walters' table shows that the Company's projected equity ratio of 50.75% in this case is below industry averages for the past nine years (2016 through 2024) and is also below the industry average of all years listed (51.64%). Mr. Walters' table shows that his recommended equity ratio for the Company in this case of 50% is significantly understated when compared to his own calculation of industry average equity ratios and trends.

**Q. Are the average equity ratios reflected in Mr. Walters' Table CCW-2 understated?**

A. Yes. According to footnote 1 of Mr. Walters' Table CCW-2, the source of the equity ratio data is "S&P Global Market Intelligence." S&P Global Market Intelligence tracks the

authorized equity ratio as a percentage of total capitalization. Total capitalization can be higher (making the equity ratio lower) because, in addition to permanent capital components, items such as short-term debt and customer deposits can be included. As described earlier in my rebuttal of Staff witness Megginson, the Company's proposed equity ratio in this instant case as a percentage of total capitalization is 42.58%, 817 basis points lower than the 50.75% proposed as a percentage of permanent capitalization. Excluding short-term debt to be consistent with the equity ratio projected by the Company in this case (as a percentage of permanent capital), the order results in a higher equity ratio. Again, in order to make proper comparisons, the Company's equity ratio, based on a percentage of permanent capital, should be compared to utilities also using an equity ratio based on percentage of permanent capital. By utilizing utility equity ratios that are based on a percentage of total capitalization to support his recommended equity ratio for the Company in this case, Mr. Walters is not making a direct like-for-like comparison at all, and thereby understating his results, which therefore should not be relied upon.

**Q. If the equity ratios reflected on Mr. Walters' Table CCW-2 are understated, what is the more appropriate comparison of average utility equity ratios?**

A. Refer to my earlier rebuttal testimony to AG witness Coppola in which I explain that actual commission-authorized equity ratios is the preferred data source for an average equity ratio analysis. I refer to my Exhibit A-32 (MRB-10) in which I researched all rate case decisions from 2020 through September 2024 of peer regulated companies and determined the authorized or approved equity ratio for each. Consistent with the Commission's Order in Case No. U-20963, the equity ratios used for comparison purposes were taken from commission orders and public filings and represent actual regulatory peer equity ratios

authorized or approved by different commissions across the country. As stated above, the average equity ratio for the peer group was 54.05%. This is significantly higher than the equity ratio of 50.75% projected by the Company and is also 405 basis points higher than the equity ratio Mr. Walters recommends for the Company in this case.

**Q. On page 8 of his direct testimony, Mr. Walters shows S&P ratings data from 2009 to 2024 in Table CCW-3 attempting to show that regulated utility companies have been able to maintain relatively strong credit ratings during periods of declining authorized ROEs. Has S&P commented recently on the credit quality of utilities?**

A. Yes. As highlighted on page 17 of Mr. Walters' direct testimony, in a January 2025 report on North American regulated utilities, S&P highlighted lower ratings headroom as "a high percentage of companies are operating with only minimal financial cushion from our downgrade threshold." Refer to Exhibit A-114 (MRB-17). S&P also notes that, in 2024, downgrades among North America's investor-owned regulated utilities outpaced upgrades for the fifth consecutive year. With regard to the industry credit outlook for 2025, S&P identifies risk that will pressure the industry's financial measures, including weak equity ratios, potential new tax legislation, and robust capital spending in challenging regulatory constructs. S&P also sights Michigan as one of the regulatory jurisdictions that they "continue to carefully monitor." It is apparent from this report that an ROE and equity ratio combination higher than the current authorized level, and certainly higher than the continued degradation proposed by Mr. Walters, is critical to protect the Company from receiving a credit downgrade in the light of the credit risks as described above.

**Q. Have rating agencies other than S&P also commented on the credit quality of regulated utilities?**

A. Yes. As referenced on page 18 of Mr. Walters' direct testimony, Moody's issued a report which it revised its outlook on the U.S. regulated utilities sector from stable to negative citing "increasingly challenging business and financial conditions stemming from higher natural gas prices, inflation and interest rates." In addition, on page 19 of his direct testimony, Mr. Walters references a report by another credit rating agency, Fitch. In describing a "deteriorating outlook for North American utilities, power & gas in 2024," Fitch cited credit headwinds that are putting pressure on utilities' credit metrics. Specifically, Fitch concluded that "the sharp escalation in interest rates has significantly narrowed the headroom in FFO fixed-charge coverage for the sector." It is clear from these reports that rating agencies have recognized a deterioration in credit metrics and credit quality for regulated utilities following what Mr. Walters describes as "periods of declining authorized ROEs." These rating agency comments highlight the importance for the Company to maintain strong financial metrics and to not manage toward the perceived low end of the credit metric bands.

**Q. On page 23 of his direct testimony, Mr. Walters states that the Company's projected equity ratio of 50.75% is "relatively higher than the equity ratio for the proxy group used to estimate the cost of equity for Consumers Energy." Mr. Walters then references his Exhibit AB-7, which shows a proxy group average equity ratio of 46.3% (including short-term debt) and 50.4% (excluding short-term debt). This is also highlighted on page 31 of Mr. Walters' direct testimony. Are either of Mr. Walters'**

**average equity ratios reflected on Exhibit AB-7 in any way relevant or comparable to the Company's projected equity ratio of 50.75% in this case?**

A. No. Refer to my earlier rebuttal testimony to AG witness Coppola's Exhibit AG-44. Like Mr. Coppola's Exhibit AG-44, the average equity ratio calculations for the proxy group on Mr. Walters' Exhibit AB-7 uses the equity ratio at the parent holding company level which may be distorted by other non-regulated balance sheet items and provides a completely inappropriate point of comparison. Mr. Walters' equity ratio analysis is clearly not based on the Commission's regulatory authorization and is therefore not comparable or relevant in determining the appropriate equity ratio for the Company in this case. Further, it is not clear which peer average Mr. Walters recommends should be used in determining the appropriate equity ratio for the Company in this case. Earlier in his direct testimony at page 6, Mr. Walters references average state authorized equity ratios in his Table CCW-2 which reflects an average of 52.25% in 2024. While the average equity ratios in this table are understated as explained earlier in my rebuttal testimony, they are dramatically higher than the 46.3% and 50.4% reflected on Mr. Walters' Exhibit AB-7 which Mr. Walters then references on page 23 of his direct testimony. For these reasons, Mr. Walters' comparison of the average equity ratios on his Exhibit AB-7 to the Company's projected equity ratio of 50.75% is not comparable or relevant and should be disregarded.

**Q. On page 23 of his direct testimony, Mr. Walters again compares the Company's projected equity ratio of 50.75% to his average equity ratio calculations of 46.3% and 50.4% as shown on his Exhibit AB-7. Mr. Walters references an order from the Arkansas Public Service Commission for the Southwestern Electric Power Company in which an imputed average capital structure of companies with comparable risk was used in determining the overall cost of capital. Does this order give weight to Mr. Walters' recommended equity ratio of 50.0%?**

A. No. First, page 23 of the Arkansas Public Service Commission order referenced by Mr. Walters states that "the Arkansas Court of Appeals has upheld that in instances where the utility's capital structure is unsound or out of sync with industry standards, a regulatory commission may calculate the cost of capital based not on the utility's actual capital structure but on a hypothetical capital structure." On Exhibit A-32 (MRB-10), the Company has shown that the average equity ratio for the Company's peer group is 54.05%. Based on this evidence, the only way in which the Company's equity ratio is "unsound or out of sync with industry standards" is that it is too low. Regardless, the Company is not aware of any instances in which the MPSC has accepted the use of an imputed average capital structure of ROE proxy group parent holding companies in developing the projected test year capital structure in a rate case proceeding. Therefore, the Arkansas Public Service Commission's Order for the Southwestern Electric Power Company referenced by Mr. Walters does not give support to his recommended equity ratio of 50.0% in this case and should be disregarded.

**Q. Does this conclude your rebuttal testimony?**

A. Yes.

MR. RUSZKIEWICZ: The Company would like to move on to witness Ann E. Bulkley. And based on stipulation of the parties, the Company moves to admit Ms. Bulkley's testimony, direct testimony, consisting of a cover page and 49 pages of prefiled testimony. Also included as part of her testimony was her Attachment A, which was a resume consisting of a cover page and 21 pages. Ms. Bulkley also had rebuttal testimony that was a cover page and 112 pages of prefiled testimony.

And then the Company also moves to admit the exhibits of Ms. Bulkley, which consists of Exhibit A-14 Schedule D-5, A-127, and A-128. With those exhibits, that concludes the offered testimony and exhibits of Ms. Bulkley.

JUDGE VARCHETTI: Thank you. Are there any objections to the admission of the direct and rebuttal testimony of Ms. Bulkley or any of the exhibits mentioned?

Hearing none, then, the testimony of Ms. Bulkley is admitted, as are the associated exhibits.

MR. RUSZKIEWICZ: Thank you, Your Honor.

(Direct Testimony, Attachment A, and Rebuttal Testimony bound in)

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

| | | |
|---|---|---|
| In the matter of the application of<br>**CONSUMERS ENERGY COMPANY**<br>for authority to increase its rates for the<br>distribution of natural gas and for other relief. | )<br>)<br>)<br>)<br>) | Case No. U-21806 |

**DIRECT TESTIMONY**

**OF**

**ANN E. BULKLEY**

**ON BEHALF OF**

**CONSUMERS ENERGY COMPANY**

December 2024

## I. INTRODUCTION AND QUALIFICATIONS

**Q. Please state your name and business address.**

A. My name is Ann E. Bulkley. My business address is One Beacon Street, Suite 2600, Boston, Massachusetts 02108. I am a Principal at The Brattle Group ("Brattle"), a consulting firm that advises clients on regulatory finance and ratemaking issues.

**Q. On whose behalf are you submitting this testimony?**

A. I am submitting this direct testimony before the Michigan Public Service Commission ("MPSC" or the "Commission") on behalf of Consumers Energy ("Consumers Energy" or the "Company").

**Q. Please describe your background and professional experience in the energy and utility industries.**

A. I hold a Bachelor's degree in Economics and Finance from Simmons College and a Master's degree in Economics from Boston University, and have more than 25 years of experience consulting to the energy industry. I have provided testimony regarding financial matters, including the cost of capital, before numerous regulatory agencies. I have advised energy and utility clients on a wide range of financial and economic issues, with primary concentrations in valuation and utility rate matters. Many of these assignments have included the determination of the cost of capital for valuation and ratemaking purposes. A summary of my professional and educational background is presented in Attachment A to this testimony.

## II. PURPOSE AND OVERVIEW OF DIRECT TESTIMONY

**Q. What is the purpose of your direct testimony?**

A. The purpose of my direct testimony is to present evidence and provide a recommendation regarding the return on equity ("ROE") for Consumers Energy's natural gas utility operations to be used for ratemaking purposes. I also address the reasonableness of the Company's proposed capital structure.

**Q. Are you sponsoring any exhibits with your direct testimony?**

A. Yes. I am sponsoring:

Exhibit A-14 (AEB-1) Schedule D-5 Cost of Common Shareholder's Equity.

**Q. Was this exhibit prepared by you or under your supervision?**

A. Yes.

**Q. Please provide a brief overview of the analyses that support your ROE recommendation.**

A. I have estimated the market-based cost of equity by applying traditional estimation methodologies to a proxy group of comparable utilities, including the constant growth form of the Discounted Cash Flow ("DCF") model, the Capital Asset Pricing Model ("CAPM"), the Empirical Capital Asset Pricing Model ("ECAPM"), and a Bond Yield Risk Premium ("BYRP" or "Risk Premium") analysis. My recommendation also takes into consideration the business and regulatory risk of the Company relative to the proxy group, and the Company's proposed capital structure as compared with the capital structures of the operating utilities of the proxy group companies. While I do not make specific adjustments to my ROE recommendation for these factors, I do consider them in the aggregate when determining where my recommended ROE falls within the range of the analytical results.

**Q. How is the remainder of your direct testimony organized?**

A. The remainder of my direct testimony is organized as follows:

- Section III provides a summary of my analyses and conclusions.
- Section IV reviews the regulatory guidelines pertinent to the development of the cost of capital.
- Section V discusses current and projected capital market conditions and the effect of those conditions on the Company's cost of equity.
- Section VI explains my selection of the proxy group.
- Section VII describes my cost of equity analyses and the basis for my recommended ROE in this proceeding.
- Section VIII provides a discussion of specific regulatory, business, and financial risks that have a direct bearing on the ROE to be authorized for the Company in this case.
- Section IX presents my conclusions and recommendations.

## III. SUMMARY OF ANALYSIS AND CONCLUSIONS

**Q. Please summarize the key factors that you consider in your analyses and upon which you base your recommended ROE.**

A. My analyses and recommendations consider the following:

- The United States ("U.S.") Supreme Court's *Hope* and *Bluefield* decisions established the standards for determining a fair and reasonable authorized ROE for public utilities, including consistency of the allowed return with the returns of other businesses having similar risk, adequacy of the return to provide access to capital and support credit quality, and the requirement that the result lead to just and reasonable rates.[1]
- The effect of current and prospective capital market conditions on the cost of equity estimation models and on investors' return requirements.
- The results of several analytical approaches that provide estimates of the Company's cost of equity. Because the Company's authorized ROE should be a forward-looking estimate over the period during which the rates will be in

[1] Federal Power Commission v. Hope Natural Gas Co., 320 U.S. 591 (1944) ("Hope"); Bluefield Waterworks & Improvement Co., v. Public Service Commission of West Virginia, 262 U.S. 679 (1923) ("Bluefield").

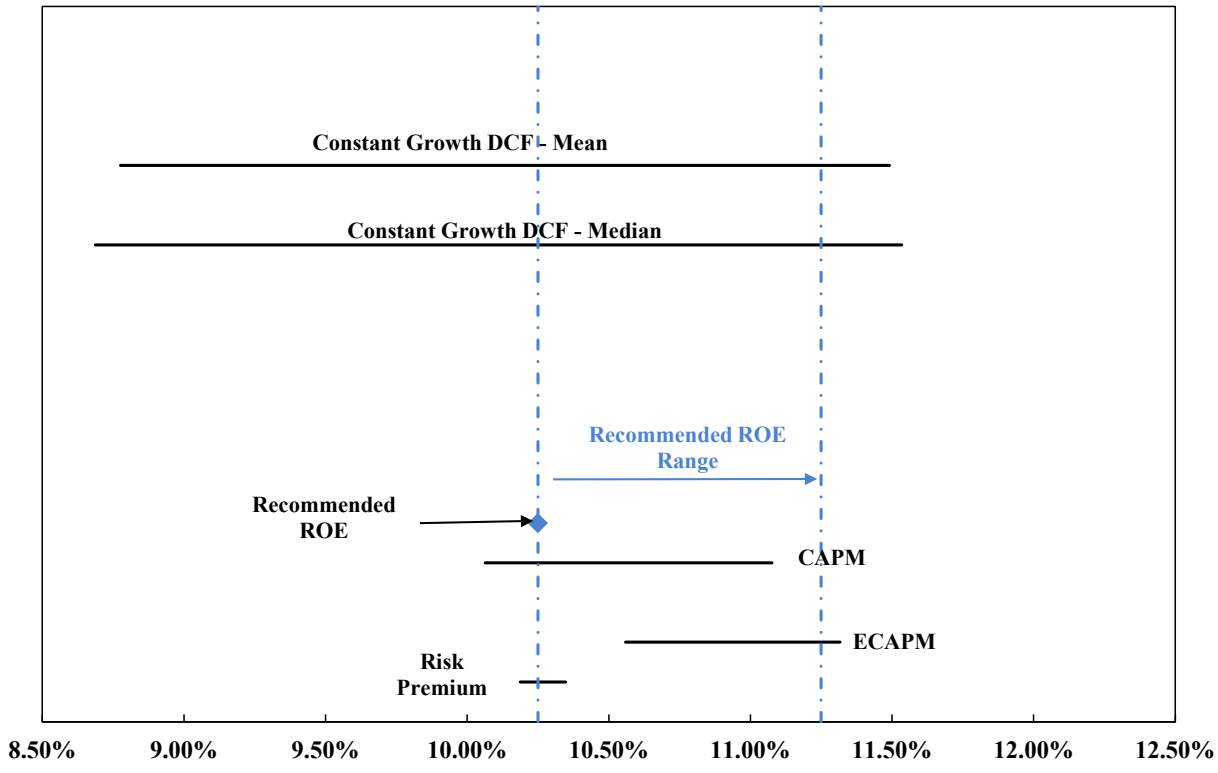
effect, these analyses rely on forward-looking inputs and assumptions (e.g. projected analyst growth rates in the DCF model, forecasted risk-free rate and market risk premium in the CAPM analysis.)

- Although the companies in my proxy group are generally comparable to Consumers Energy, each company is unique, and no two companies have the exact same business and financial risk profiles. Accordingly, I consider the Company's regulatory, business, and financial risks relative to a proxy group of comparable companies in determining where the Company's ROE should fall within the reasonable range of analytical results to appropriately account for any residual differences in risk.

**Q. What are the results of the models that you have used to estimate the market-based cost of equity for Consumers Energy?**

A. Figure 1 summarizes the range of results produced by the cost of equity analyses.

**Figure 1: Summary of Cost of Equity Analytical Results**




As shown, the range of results across all methodologies is wide. While it is common to consider multiple models to estimate the cost of equity, it is particularly important when

the range of results varies considerably across methodologies. As a result, my ROE recommendation considers the range of results of analyses, as well as the company-specific risk factors and current and prospective capital market conditions expected during the time when rates set in this case would be in effect.

**Q. What is your recommended ROE for the Company in this proceeding?**

A. Considering the analytical results of the market-based cost of equity models, current and prospective capital market conditions, and the Company's regulatory, business, and financial risk relative to the proxy group, I conclude that an ROE in the range of 10.25% to 11.25% is reasonable, and within that range, the Company is requesting an ROE of 10.25%.

## IV. REGULATORY GUIDELINES

**Q. Please describe the principles that guide the establishment of the cost of capital for a regulated utility.**

A. The U.S. Supreme Court's precedent-setting *Hope* and *Bluefield* cases established the standards for determining the fairness or reasonableness of a utility's allowed ROE. Among the standards established by the Court in those cases are: (1) consistency with other businesses having similar or comparable risks; (2) adequacy of the return to support credit quality and access to capital; and (3) the principle that the result reached, as opposed to the methodology employed, is the controlling factor in arriving at just and reasonable rates. [2]

**Q. Has the Commission provided similar guidance in establishing the appropriate return on common equity?**

A. Yes. For example, in its decision in Case No. U-20963, the Commission stated that:

[2] *Bluefield*, 262 U.S. at 692-93; *Hope*, 320 U.S. at 603.

> The criteria for establishing a fair ROR for public utilities is rooted in the language of the landmark United States (U.S.) Supreme Court cases *Bluefield Waterworks & Improvement Co v Public Serv Comm of West Virginia*, 262 US 679; 43 S Ct 675; 67 L Ed 1176 (1923), and *Federal Power Comm v Hope Natural Gas Co*, 320 US 591; 64 S Ct 281; 88 L Ed 333 (1944). The Supreme Court has made clear that, in establishing a fair ROR, consideration should be given to both investors and customers. As stated on page 12 of the December 23, 2008 order in U-15244 (December 23 order), "the rate of return should not be so high as to place an unnecessary burden on ratepayers, yet should be high enough to ensure investor confidence in the financial soundness of the enterprise." Nevertheless, the Commission observes that the determination of what is fair or reasonable, "is not subject to mathematical computation with scientific exactitude but depends upon a comprehensive examination of all factors involved, having in mind the objective sought to be attained in its use." [Meridian Twp v City of East Lansing, 342 Mich 734, 749; 71 NW2d 234 (1955).[3]]

This guidance is in accordance with the *Hope* and *Bluefield* decisions and the principles that I have employed to estimate the cost of equity and recommend an ROE for the Company, including the principle that an allowed rate of return must be sufficient to enable regulated companies like Consumers Energy to attract capital on reasonable terms.

**Q. Is fixing a fair rate of return just about protecting the utility's interests?**

A. No. As the court noted in *Bluefield*, a proper rate of return not only assures "confidence in the financial soundness of the utility and should be adequate, under efficient and economical management, to maintain and support its credit [but also] enable[s the utility] to raise the money necessary for the proper discharge of its public duties."[4] As the Court

[3] MPSC Case No. U-20963, 12/22/2021 Order, at 221-222.

[4] *Bluefield*, 262 U.S. at 679, 693.

went on to explain in *Hope*, "[t]he rate-making process … involves balancing of the investor and consumer interests."[5]

**Q. Why is it important for a utility to have a reasonable opportunity to earn a return that is adequate to attract capital at reasonable terms?**

A. An ROE that is adequate to attract capital at reasonable terms enables the Company to continue to provide safe, reliable gas service while maintaining its financial integrity. The authorized return should be commensurate with returns expected elsewhere in the market for investments of equivalent risk. If it is not, debt and equity investors will seek alternative investment opportunities for which the expected return reflects the perceived risks, thereby inhibiting the Company's ability to attract capital at reasonable cost, which ultimately has a negative effect on customers.

**Q. Is a utility's ability to attract capital also affected by the ROEs that are authorized for other utilities?**

A. Yes. Utilities compete directly for capital with other investments of similar risk, which include other electric, natural gas, and water utilities nationally. Therefore, the ROE authorized for a utility sends an important signal to investors regarding whether there is regulatory support for financial integrity, dividends, growth, and fair compensation for business and financial risk within that jurisdiction generally, and for that utility particularly. The cost of capital represents an opportunity cost to investors. If higher returns are available elsewhere for other investments of comparable risk over the same time-period, investors have an incentive to direct their capital to those alternative

[5] *Hope*, 320 U.S. at 591, 603.

investments. Thus, an authorized ROE significantly below authorized ROEs for other utilities can inhibit the utility's ability to attract capital for investment.

**Q. What is the standard for setting the ROE in any jurisdiction?**

A. The stand-alone ratemaking principle is a foundation of jurisdictional ratemaking. This principle requires that the rates that are charged in any operating jurisdiction be for the costs incurred in that jurisdiction. The stand-alone ratemaking principle ensures that customers in each jurisdiction only pay for the costs of the service provided in that jurisdiction, which is not influenced by the business operations in other operating companies. Consistent with this principle, the cost of equity analysis is performed for an individual operating company as a stand-alone entity. As such, I have evaluated the investor-required return for Consumers Energy's natural gas utility operations in Michigan.

**Q. Does the fact that Consumers Energy is a wholly owned subsidiary of CMS Energy Corporation ("CMS"), a publicly traded company, affect your analysis?**

A. No. In this proceeding, consistent with stand-alone ratemaking principles, it is appropriate to establish the cost of equity for Consumers Energy's natural gas operations, not its publicly-traded parent, CMS. More importantly, however, it is appropriate to establish a cost of equity and capital structure that provide the ability to attract capital on reasonable terms for Consumers Energy's natural gas operations, both on a stand-alone basis and within CMS. While Consumers Energy is committed to investing the required capital to provide safe and reliable natural gas service, because it is a subsidiary of CMS, the Company competes with the other CMS subsidiaries for discretionary investment capital. In determining how to allocate its finite discretionary capital resources, it would be reasonable for CMS to consider the authorized ROE of each of its subsidiaries.

**Q. Are the regulatory framework, the authorized ROE, and equity ratio important to the financial community?**

A. Yes. The regulatory framework is one of the most important factors in investors' assessments of risk. Specifically, the authorized ROE and equity ratio for regulated utilities is very important for determining the degree of regulatory support for reinforcing a utility's creditworthiness and financial stability in the jurisdiction. To the extent authorized returns in a jurisdiction are lower than the returns that have been authorized more broadly, such actions are considered by both debt and equity investors in the overall risk assessment of the regulatory jurisdiction in which the company operates. The direct testimony of Company witness Marc R. Bleckman describes in further detail the effect of the authorized ROE and equity ratio on credit quality as well as rating agencies' assessment of Michigan's regulatory environment.

**Q. What are your conclusions regarding regulatory guidelines?**

A. The ratemaking process is premised on the principle that, in order for investors and companies to commit the capital needed to provide safe and reliable utility services, a utility must have a reasonable opportunity to recover the return of, and the market-required return on, its invested capital. Accordingly, the Commission's order in this proceeding should establish rates that provide the Company with a reasonable opportunity to earn an ROE that is adequate to attract capital at reasonable terms and sufficient to ensure its financial integrity. It is important for the ROE authorized in this proceeding to take into consideration current and projected capital market conditions, as well as investors' expectations and requirements for both risks and returns. Because utility operations are capital-intensive, regulatory decisions should enable the utility to attract capital at

reasonable terms under a variety of economic and financial market conditions. Providing the opportunity to earn a market-based cost of capital supports the financial integrity of the Company, which is in the interest of both customers and shareholders.

## V. CAPITAL MARKET CONDITIONS

**Q. Why is it important to analyze capital market conditions?**

A. The models used to estimate the cost of equity rely on market data and thus the results of those models can be affected by prevailing market conditions at the time the analysis is performed. While the ROE established in a rate proceeding is intended to be forward-looking, the analysis uses current and projected market data, including stock prices, dividends, growth rates, and interest rates, in the cost of equity estimation models to estimate the investor-required return for the subject company.

Analysts and regulatory commissions recognize that current market conditions affect the results of the cost of equity estimation models. As a result, it is important to consider the effect of the market conditions on these models when determining an appropriate range for the ROE, and the ROE to be used for ratemaking purposes for a future period. If investors do not expect current market conditions to be sustained in the future, it is possible that the cost of equity estimation models will not provide an accurate estimate of investors' required return during that rate period. Therefore, it is important to consider projected market data to estimate the return for that forward-looking period.

**Q. Do changes in capital market conditions since the Company's last rate proceeding indicate an elevated cost of equity?**

A. Yes. Core inflation and long-term bond yields compared to the Company's last rate proceeding demonstrates an elevated cost of equity. As shown in Figure 2, short-term and

long-term interest rates as well as core inflation have remained high since the Commission adopted the settlement which includes an ROE of 9.90% in the Company's last gas rate case filed in 2023. While inflation has declined from its peak in 2022, it still remains above the level of the Federal Reserve's target of 2%.

**Figure 2: Change in Market Conditions Since Company's Last Rate Case[6]**

| Docket | Date | Federal Funds Rate | 30-Day Avg 30 Year Treasury Bond Yield | Core Inflation Rate | Authorized ROE |
|---|---|---|---|---|---|
| Docket No. U-21490 (Direct Filing) | 2023-11-17 | 5.33% | 4.86% | 4.02% | 9.90% |
| Docket No. U-21490 (Rebuttal Filing) | 2024-04-26 | 5.33% | 4.57% | 3.21% | 9.90% |
| Current | 2024-10-31 | 4.83% | 4.30% | 3.26% | |
| Change since Direct | | -0.50% | -0.56% | -0.76% | |
| Change since Rebuttal | | -0.50% | -0.28% | 0.05% | |

**Q. What has the level of inflation been over the past few years?**

A. As shown in Figure 3, core inflation increased steadily beginning in early 2021, rising from 1.40% in January 2021 to a high of 6.64% in September 2022, which was the largest 12-month increase since 1982.[7] Since that time, while core inflation has declined in response to the Federal Reserve's monetary policy, it continues to remain significantly above the Federal Reserve's target level of 2.0%.

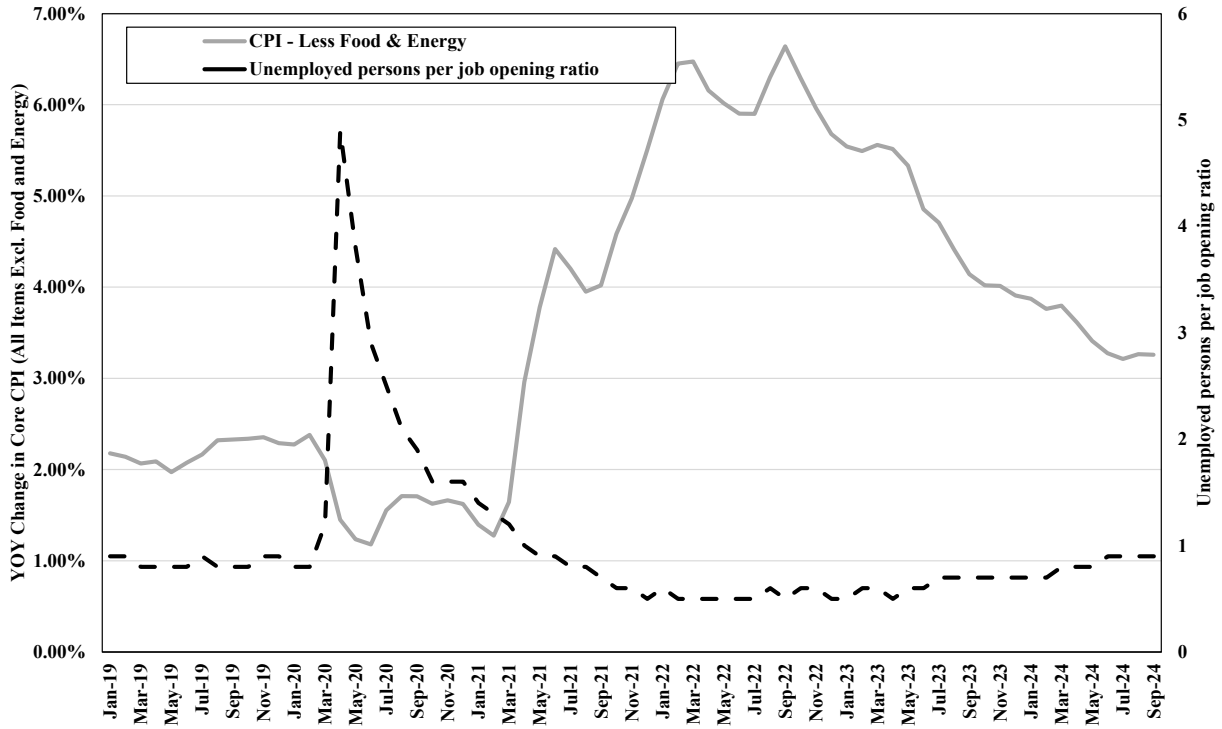
[6] St. Louis Federal Reserve Bank; Bureau of Labor Statistics. While the prior rate case direct testimony and rebuttal testimony were filed on December 15, 2023 and May 17, 2024, respectively, the analysis used to support the recommendation for the Company's ROE relied on data from November 17, 2023 and April 26, 2024, respectively.

[7] *Bloomberg,* Pickert, Reade, "Core US Inflation Rises to 40-Year High, Securing Big Fed Hike", October 13, 2022.

Figure 3 presents the year-over-year change in core inflation, as measured by the Consumer Price Index excluding food and energy prices as published by the Bureau of Labor Statistics. I considered core inflation because it is the preferred inflation indicator of the Federal Reserve for determining the direction of monetary policy. Core inflation is preferred by the Federal Reserve because it removes the effect of food and energy prices, which can be highly volatile.

In addition, I also considered the ratio of unemployed persons per job opening, which was 0.9 in September 2024 (the most recent data available at the time of writing) and has been consistently below 1.0 since April 2021, despite the Federal Reserve's accelerated policy normalization. This indicates sustained strength in the labor market. Given the Federal Reserve's dual mandate of maximum employment and price stability, the strength in the labor market allowed the federal reserve to focus on the priority of reducing inflation and pursue the restrictive monetary policy needed to reduce inflation.

**Figure 3: Core Inflation and Unemployed Persons-to-Job Openings, January 2019 to September 2024[8]**




[8] Bureau of Labor Statistics.

**Q. What policy actions has the Federal Reserve enacted to respond to increased inflation?**

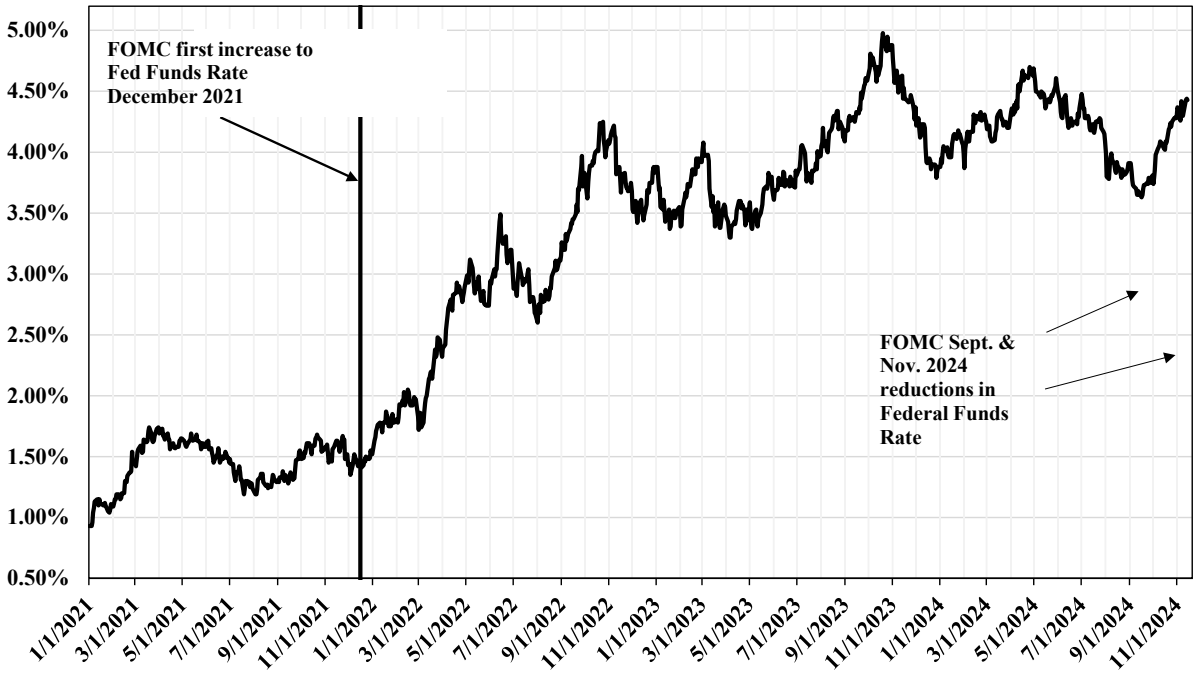
A. The dramatic increase in inflation prompted the Federal Reserve to pursue an aggressive normalization of monetary policy, removing the accommodative policy programs used to mitigate the economic effects of COVID-19. Between the March 2022 Federal Open Market Committee ("FOMC") meeting and the July 2023 FOMC meeting, the Federal Reserve increased the target federal funds rate through a series of increases from a range of 0.00% to 0.25% to a range of 5.25% to 5.50%. As discussed below, in light of the progress on reducing inflation and the balancing of the dual mandate, the Federal Reserve lowered the federal funds rate in September and November 2024 by a total of 75 basis points to a range of 4.50% to 4.75%.

**Q. How have yields on long-term government bonds responded to the Federal Reserve's use of monetary policy?**

A. As shown in Figure 4, beginning in December 2021, as the Federal Reserve substantially increased the federal funds rate in response to persistent increased levels of inflation, longer-term interest rates increased. Since the Federal Reserve's December 2021 meeting, when the first increase to the federal funds rate occurred, the yield on 10-year Treasury bonds has increased substantially from 1.47% to a peak of 4.95% in October 2023, remaining well above 2021 levels throughout 2024. It is important to note that while the FOMC has reduced the Federal Funds Rate twice in recent months, the yield on the 30-year Treasury bond responded only briefly, on the expectation of the first rate cut in September 2024, but has risen steadily since that time. As of November 14, which was a week following the second reduction to the Federal Funds Rate, the yield on the 30-year Treasury

bond was 4.43%, which is substantially higher than the yield just prior to the actions of the FOMC in September 2024.

**Figure 4: 10-Year Treasury Bond Yield, Janaury 2021 through September 30, 2024[9]**




**Q. What is the expected path of monetary policy over the near-term?**

A. While the Federal Reserve cut the interest rate by 50 basis points in September 2024 and 25 basis points in November 2024, Chairman Powell has repeatedly noted that the FOMC is "not on any preset course" and will "continue to make our decisions meeting to meeting."[10] Most recently, on November 14, 2024, Chairman Powell noted that there was no rush to lower interest rates, noting a solid job market, ongoing economic growth, and inflation that remains above its 2% target. Responding to questions regarding the effect of higher tariffs and changes in immigration policy on economic growth and inflation,

[9] S&P Capital IQ Pro.

[10] *Id.*

Chairman Powell noted that the answer is not obvious until we see the actual policies; however, he noted that "The economy is not sending any signals that we need to be in a hurry to lower rates. The strength we are currently seeing in the economy gives us the ability to approach our decisions carefully." [11]

In addition to the changes expected with short-term interest rates, economists have also shifted their targets for long-term government bond yields with *Reuters* noting that BofA Global Research increased their near-term target for long-term government bond yields from a range of 3.5% to 4.25% to a range of 4.25% to 4.75%.[12]

**Q. What are expectations for the yields on long-term government bonds?**

A. Economists consider the expected policy of the Federal Reserve in the development of their forecasts of long-term government bond yields and, prior to the FOMC's decision to reduce the federal funds rate at the September 2024 meeting, had projected a decrease in the federal funds rate. For example, *Blue Chip Financial Forecasts* provides a forecast of both the federal funds rate and the yield on the 30-year Treasury bond. In the most recent published *Blue Chip Financial Forecasts* report, economists projected the federal funds rate to decline from 4.6% in Q4/2024 to 3.3% in Q1/2026.[13] However, economists' consensus estimate of the yield on the 30-year Treasury bond is expected to remain relatively stable over the same time-period. The yield on the 30-year Treasury bond as reported by *Blue Chip Financial Forecasts* is expected to range from 4.1% in Q4/2024 to 4.0% in Q1/2026.[14] Therefore, economists, who consider the expected policy of the

[11] Ann Saphir and Howard Schneider, "Powell says no need for Fed to rush rate cuts given strong economy," *Reuters*, November 14, 2024.

[12] *Id*.

[13] *Blue Chip Financial Forecasts*, Vol. 43, No. 10, October 1, 2024, at 2.

[14] *Id.*

Federal Reserve, expect the yield on the 30-year Treasury bond to remain elevated over the near-term.

**Q. What are your conclusions regarding the effect of current market conditions on the cost of equity for the Company?**

A. Due to their effect on the estimated cost of equity, it is important that current and projected market conditions be considered in setting the forward-looking ROE in this proceeding. As shown in Figure 2, long-term interest rates remain elevated when compared to the Company's last rate proceeding. Further, while the FOMC decreased the federal funds rate, there is uncertainty regarding the policies of the new administration with respect to tariffs and immigration, which are projected to be inflationary. Recently, bond yields have been resistant to declines in the federal funds rate, and yields are generally consistent with the conditions that existed at the time of the Company's last rate proceeding.

## VI. PROXY GROUP SELECTION

**Q. Please provide a brief profile of Consumers Energy's natural gas utility operations.**

A. Consumers Energy's natural gas operations include gas transmission, storage, and distribution system and is a wholly owned subsidiary of CMS Energy Corporation. The Company provides natural gas service to approximately 1.8 million customers in Michigan with approximately $2.2 billion in operating revenues from natural gas sales.[15] As of December 31, 2023, the Company's net utility natural gas plant was approximately

[15] Consumers Energy Company, Annual Report of Natural Gas Utilities to the Michigan Public Service Commission, December 31, 2023, at pages 300-301.

$9.7 billion.[16] Consumers Energy currently has an investment-grade long-term rating of A- (Outlook: Stable) from S&P and A3 (Outlook: Stable) from Moody's.[17]

**Q. Why have you used a group of proxy companies to estimate the cost of equity for Consumers Energy?**

A. In this proceeding, the cost of equity is being estimated for a natural gas utility that is not itself publicly traded. Because the cost of equity is a market-based concept and the Company's operations do not make up the entirety of a publicly traded entity, it is necessary to establish a group of companies that is both publicly traded and comparable to the Company in certain fundamental business and financial respects to serve as its "proxy" for purposes of estimating the cost of equity.

Even if the Company was a publicly traded entity, it is possible that transitory events could bias its market value over a given period. A significant benefit of using a proxy group is that it moderates the effects of unusual events that may be associated with any one company. The proxy companies used in my analyses all possess a set of operating and risk characteristics that are substantially comparable to the Company, and thus provide a reasonable basis to estimate the appropriate cost of equity for the Company.

**Q. How did you select the companies included in your proxy group?**

A. I began with the group of nine companies that *Value Line* classifies as Natural Gas Distribution Utilities and applied the following screening criteria to select companies that:

- pay consistent quarterly cash dividends, because this is a requirement for the constant growth DCF model;
- have investment grade long-term issuer ratings from S&P and/or Moody's;

[16] Exhibit A-2 (HLR-8), Schedule B-6, page 1.

[17] S&P Global Market Intelligence, accessed October 29, 2024. Moody's as of April 27, 2023.

- have positive long-term earnings growth forecasts from at least two utility industry equity analysts;
- derive more than 70.00% of their total operating income from regulated operations;
- derive more than 60.00% of regulated operating income from gas distribution operations; and
- were not parties to a merger or transformative transaction during the analytical periods relied on.

**Q. What is the composition of your proxy group?**

A. The screening criteria discussed above is shown in Exhibit A-14 (AEB-1), Schedule D-5, page 2, and results in a proxy group consisting of the companies shown in Figure 5.

**Figure 5: Proxy Group**

| Company | Ticker |
|---|---|
| Atmos Energy Corporation | ATO |
| NiSource Inc. | NI |
| Northwest Natural Gas Company | NWN |
| ONE Gas, Inc. | OGS |
| Southwest Gas Corporation | SWX |
| Spire, Inc. | SR |

## VII. COST OF EQUITY ESTIMATION

**Q. Please briefly discuss the ROE in the context of a regulated utility.**

A. The rate of return for a regulated utility is the weighted average cost of capital, in which the costs of the individual sources of capital are weighted by their respective proportion (i.e. book values) in the utility's capital structure. The ROE is the cost rate applied to the equity capital in calculating the rate of return. While the costs of debt and preferred stock can be directly observed, the cost of equity is market-based and, therefore, must be estimated based on observable market data when establishing the ROE.

**Q. How is the required cost of equity determined?**

A. The required cost of equity is estimated by using analytical techniques that rely on market-based data to quantify investor expectations regarding equity returns, adjusted for certain incremental costs and risks. Informed judgment is then applied to determine where the company's cost of equity falls within the range of results produced by multiple analytical techniques. The key consideration in determining the cost of equity is to ensure that the methodologies employed reasonably reflect investors' views of the financial markets in general, as well as the subject company (in the context of the proxy group), in particular.

**Q. What methods did you use to estimate the cost of equity for the Company in this proceeding?**

A. I consider the results of the constant growth form of the DCF model, the CAPM, the ECAPM, and a BYRP analysis. A reasonable cost of equity estimate appropriately considers alternative methodologies and the reasonableness of their individual and collective results.

**Q. Is it important to use more than one analytical approach?**

A. Yes. Because the cost of equity is not directly observable, it must be estimated based on both quantitative and qualitative information. When faced with the task of estimating the cost of equity, analysts and investors are inclined to gather and evaluate as much relevant data as reasonably can be analyzed. Several models have been developed to estimate the cost of equity, and I use multiple approaches to estimate the cost of equity. As a practical matter, however, all of the models available for estimating the cost of equity are subject to limiting assumptions or other methodological constraints. Consequently, many

well-regarded finance texts recommend using multiple approaches when estimating the cost of equity. For example, Copeland, Koller, and Murrin[18] suggest using the CAPM and Arbitrage Pricing Theory model, while Brigham and Gapenski[19] recommend the CAPM, DCF, and BYRP approaches.

Further, each model relies on different assumptions, certain of which better reflect current and projected market conditions at different times. For example, the CAPM and ECAPM analyses rely directly on interest rates as an assumption in the models and therefore may more directly reflect the market conditions expected when the Company's rates are in effect. Accordingly, it is important to use multiple analytical approaches to ensure that the cost of equity results reflect market conditions that are expected during the period that the Company's rates will be in effect.

**A. Constant Growth DCF Model**

**Q. Please describe the DCF approach.**

A. The DCF approach is based on the theory that a stock's current price represents the present value of all expected future cash flows. In its most general form, the DCF model is expressed as follows:

$$P_0 = \frac{D_1}{(1+k)} + \frac{D_2}{(1+k)^2} + \ldots + \frac{D_\infty}{(1+k)^\infty} \qquad [1]$$

Where $P_0$ represents the current stock price, D1…D∞ are all expected future dividends, and k is the discount rate, or required cost of equity. Equation [1] is a standard present value calculation that can be simplified and rearranged into the following form:

[18] Tom Copeland, Tim Koller and Jack Murrin, *Valuation: Measuring and Managing the Value of Companies* (3rd ed. 2000), at 214.

[19] Eugene Brigham and Louis Gapenski, *Financial Management: Theory and Practice* (7th ed. 1994), at 341.

$$k = \frac{D_0(1+g)}{P_0} + g \qquad [2]$$

Equation [2] is often referred to as the Constant Growth DCF model in which the first term is the expected dividend yield and the second term is the expected long-term growth rate.

**Q. What assumptions are required for the constant growth DCF model?**

A. The constant growth DCF model requires the following assumptions: (1) a constant growth rate for earnings and dividends; (2) a stable dividend payout ratio; (3) a constant price-to-earnings ratio; and (4) a discount rate greater than the expected growth rate. To the extent that any of these assumptions are violated, considered judgment and/or specific adjustments should be applied to the results.

**Q. What market data did you use to calculate the dividend yield in your constant growth DCF model?**

A. The dividend yield in my constant growth DCF model is based on the proxy companies' current annual dividend and average closing stock prices over the 30-, 90-, and 180-trading days as of September 30, 2024.

**Q. Why did you use three averaging periods for stock prices?**

A. In my constant growth DCF model, I use an average of recent trading days to calculate the term $P_0$ in the DCF model to ensure that the cost of equity is not skewed by anomalous events that may affect stock prices on any given trading day. The averaging period should also be reasonably representative of expected capital market conditions over the long term.

**Q. Did you make any adjustments to the dividend yield to account for periodic growth in dividends?**

A. Yes. Because utility companies tend to increase their quarterly dividends at different times throughout the year, it is reasonable to assume that dividend increases will be evenly

distributed over calendar quarters. Given that assumption, it is reasonable to apply one-half of the expected annual dividend growth rate for purposes of calculating the expected dividend yield component of the DCF model. This adjustment ensures that the expected first-year dividend yield is, on average, representative of the coming 12-month period, and does not overstate the aggregated dividends to be paid during that time.

**Q. Why is it important to select appropriate measures of long-term growth in applying the DCF model?**

A. In its constant growth form, the DCF model (i.e. Equation [2] shown previously) assumes a single long-term growth rate in perpetuity. In order to reduce the long-term growth rate to a single measure, one must assume that the dividend payout ratio remains constant and that earnings per share ("EPS"), dividends per share, and book value per share all grow at the same constant rate. However, over the long run, dividend growth can only be sustained by earnings growth, meaning earnings are the fundamental driver of a company's ability to pay dividends. Therefore, projected EPS growth is the appropriate measure of a company's long-term growth. In contrast, changes in a company's dividend payments are based on management decisions related to cash management and other factors. For example, a company may decide to retain earnings rather than pay out a portion of those earnings to shareholders through dividends. Therefore, dividend growth rates are less likely than earnings growth rates to accurately reflect investor perceptions of a company's growth prospects. Accordingly, I have incorporated a number of sources of long-term EPS growth rates into the constant growth DCF model.

**Q. What sources of long-term growth rates did you rely on in your constant growth DCF model?**

A. My constant growth DCF model incorporates three sources of long-term projected EPS growth rates: (1) *Zacks Investment Research* (*Zacks*); (2) Yahoo! Finance; and (3) *Value Line*.

**Q. How do you calculate the range of results for the constant growth DCF models?**

A. I calculate the low-end result for the constant growth DCF model using the minimum growth rate of the three sources (i.e. the lowest of the *Zacks*, Yahoo! Finance, and *Value Line* projected EPS growth rates) for each of the proxy group companies. I use a similar approach to calculate a high-end result, using the maximum growth rate of the three sources for each proxy group company. Lastly, I also calculate results using the average EPS growth rate from all three sources for each proxy group company.

**Q. Please summarize the results of your constant growth DCF analyses.**

A. Exhibit A-14 (AEB-1), Schedule D-5, pages 3 through 5, and Figure 6 summarize the results of the constant growth DCF models.

**Figure 6: Summary of Constant Growth DCF Results**

| | Minimum Growth Rate | Average Growth Rate | Maximum Growth Rate |
|---|---|---|---|
| Mean Results: | | | |
| 30-Day Avg. Stock Price | 8.59% | 9.87% | 11.30% |
| 90-Day Avg. Stock Price | 8.79% | 10.06% | 11.50% |
| 180-Day Avg. Stock Price | 8.95% | 10.23% | 11.66% |
| Average | 8.78% | 10.05% | 11.49% |
| Median Results: | | | |
| 30-Day Avg. Stock Price | 8.48% | 9.83% | 11.33% |
| 90-Day Avg. Stock Price | 8.72% | 10.05% | 11.57% |
| 180-Day Avg. Stock Price | 8.86% | 10.17% | 11.71% |
| Average | 8.69% | 10.02% | 11.54% |

**Q. Have regulatory commissions acknowledged the reasonableness of considering multiple models to estimate the cost of equity given the current capital market conditions?**

A. Yes. For example, in its May 2022 decision establishing the cost of equity for Aqua Pennsylvania, Inc., the Pennsylvania Public Utility Commission concluded that, based on high inflation and increased interest rates, weight should be placed on risk premium models, such as the CAPM, in addition to the DCF, in the determination of the ROE:

> To help control rising inflation, the Federal Open Market Committee has signaled that it is ending its policies designed to maintain low interest rates. Aqua Exc. at 9. Because the DCF model does not directly account for interest rates, consequently, it is slow to respond to interest rate changes. However, I&E's CAPM model uses forecasted yields on ten-year Treasury bonds, and accordingly, its methodology captures forward looking changes in interest rates.
>
> Therefore, our methodology for determining Aqua's ROE shall utilize both I&E's DCF and CAPM methodologies. As noted above, the Commission recognizes the importance of informed judgment and information provided by other ROE models. In the 2012 PPL Order, the Commission considered PPL's CAPM and RP methods, tempered by informed judgment, instead of DCF-only results. We conclude that methodologies other than the DCF can be used as a check upon the reasonableness of the DCF derived ROE calculation. Historically, we have relied primarily upon the DCF methodology in arriving at ROE determinations and have utilized the results of the CAPM as a check upon the reasonableness of the DCF derived equity return. As such, where evidence based on other methods suggests that the DCF-only results may understate the utility's ROE, we will consider those other methods, to some degree, in determining the appropriate range of reasonableness for our equity return determination. In light of the above, we shall determine an appropriate ROE for Aqua using informed

> judgement based on I&E's DCF and CAPM methodologies.[20]
>
> ***
>
> We have previously determined, above, that we shall utilize I&E's DCF and CAPM methodologies. I&E's DCF and CAPM produce a range of reasonableness for the ROE in this proceeding from 8.90% [DCF] to 9.89% [CAPM]. Based upon our informed judgment, which includes consideration of a variety of factors, including increasing inflation leading to increases in interest rates and capital costs since the rate filing, we determine that a base ROE of 9.75% is reasonable and appropriate for Aqua.[21]

**B. CAPM Analysis**

**Q. Please briefly describe the Capital Asset Pricing Model.**

A. The CAPM is a risk premium approach that estimates the cost of equity for a given security as a function of a risk-free return plus a risk premium to compensate investors for the non-diversifiable or "systematic" risk of that security.[22] This second component is the product of the market risk premium and the beta coefficient, which measures the relative riskiness of the security being evaluated.

The CAPM is defined by four components, each of which must theoretically be a forward-looking estimate:

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[20] Pennsylvania Public Utility Commission, Docket Nos. R-2021-3027385 and R-2021-3027386, Opinion and Order, May 12, 2022, at 154-155.

[21] *Id*., at 177-178.

[22] Systematic risk is the risk inherent in the entire market or market segment, which cannot be diversified away using a portfolio of assets. Unsystematic risk is the risk of a specific company that can, theoretically, be mitigated through portfolio diversification.

$$K_e = r_f + \beta(r_m - r_f) \quad [3]$$

Where:

$K_e$ = the required market ROE;

$\beta$ = the beta coefficient of an individual security;

$r_f$ = the risk-free rate of return; and

$r_m$ = the required return on the market as a whole.

In this specification, the term ($r_m - r_f$) represents the market risk premium. According to the theory underlying the CAPM, because unsystematic risk can be diversified away, investors should only be concerned with systematic or non-diversifiable risk. Systematic risk is measured by beta, which is a measure of the volatility of a security as compared to the market as a whole. Beta is defined as:

$$\beta = \frac{Covariance\ (r_e, r_m)}{Variance\ (r_m)} \quad [4]$$

*Variance* ($r_m$) represents the variance of the market return, which is a measure of the uncertainty of the general market. *Covariance* ($r_e$, $r_m$) represents the covariance between the return on a specific security and the general market, which reflects the extent to which the return on that security will respond to a given change in the general market return. Thus, beta represents the risk of the security relative to the general market.

**Q. What risk-free rate did you use in your CAPM analyses?**

A. I rely on three sources for my estimate of the risk-free rate: (1) the current 30-day average yield on 30-year U.S. Treasury bonds, which is 4.07%;[23] (2) the average projected 30-year U.S. Treasury bond yield for the first quarter of 2025 through the first quarter of 2026,

[23] S&P IQ Pro, as of September 30, 2024.

which is 4.02%;[24] and (3) the average projected 30-year U.S. Treasury bond yield for 2026 through 2030, which is 4.30%.[25]

**Q. What beta coefficients did you use in your CAPM analysis?**

A. As shown in Exhibit A-14 (AEB-1), Schedule D-5, pages 6 through 11, I use the beta coefficients for the proxy group companies as reported by *Bloomberg* and *Value Line*. The beta coefficients reported by *Bloomberg* are calculated using 10 years of weekly returns relative to the S&P 500 Index. The beta coefficients reported by *Value Line* are calculated based on five years of weekly returns relative to the New York Stock Exchange Composite Index. Additionally, as shown in Exhibit A-14 (AEB-1), Schedule D-5, pages 12 through 14, I also considered an additional CAPM analysis that relies on the long-term average utility beta coefficient for the companies in my proxy group from 2013 through 2023, which are presented in Exhibit A-14 (AEB-1), Schedule D-5, page 15.

**Q. How do you estimate the market risk premium in the CAPM?**

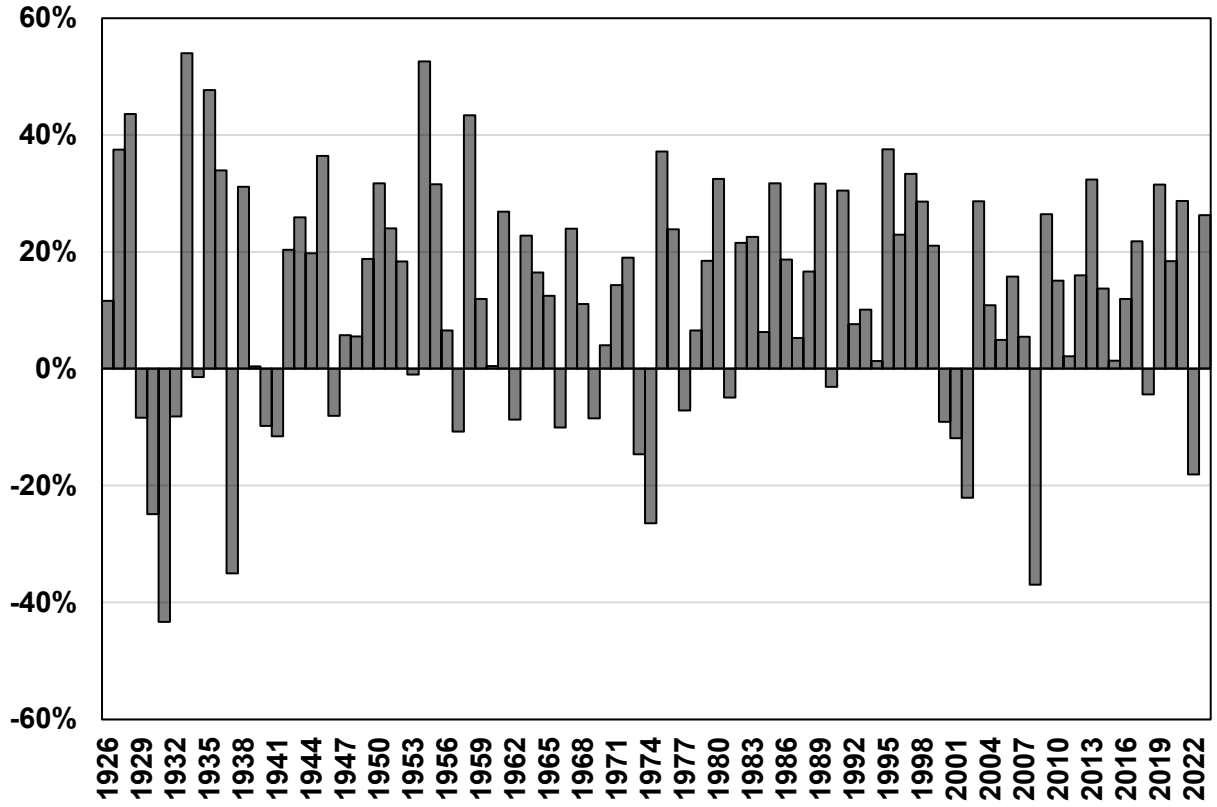
A. I estimate the market risk premium as the difference between the implied expected equity market return and the risk-free rate. As shown in Exhibit A-14 (AEB-1), Schedule D-5, pages 16 through 21, the expected market return is calculated using the constant growth DCF model discussed previously as applied to the companies in the S&P 500 Index. Based on an estimated market capitalization-weighted dividend yield of 1.52% and a weighted long-term growth rate of 10.45%, the estimated required market return for the S&P 500 Index as of September 30, 2024 is 12.04%.

[24] *Blue Chip Financial Forecasts*, Vol. 43, No. 10, October 1, 2024, at 2.
[25] *Blue Chip Financial Forecasts*, Vol. 43, No. 6, May 31, 2024, at 14.

**Q. How does the expected market return compare to observed historical market returns?**

A. As show in Figure 7, given the range of annual equity returns that have been observed over the past century, a current expected market return of 12.04% is reasonable. In 52 out of the past 98 years (or approximately 53% of observations), the realized equity market return was at least 12.04% or greater.

**Figure 7: Realized U.S. Equity Market Returns (1926–2023)[26]**




**Q. Did you consider another form of the CAPM in your analysis?**

A. Yes. I have also considered the results of an ECAPM in estimating the cost of equity for the Company.[27] The ECAPM calculates the product of the adjusted beta coefficient and

[26] Depicts total annual returns on large company stocks, as reported in the 2022 *Kroll* SBBI Yearbook for 1926-2022 and from S&P Capital IQ Professional for 2023.

[27] See, e.g., Roger A. Morin, *New Regulatory Finance*, Public Utilities Reports, Inc., June 1, 2006, at 189.

the market risk premium and applies a weight of 75.00% to that result. The model then applies a 25.00% weight to the market risk premium without any effect from the beta coefficient. The results of the two calculations are summed, along with the risk-free rate, to produce the ECAPM result, as noted in Equation [5] below:

$$k_e = r_f + 0.75\beta(r_m - r_f) + 0.25(r_m - r_f) \qquad [5]$$

Where:

$k_e$ = the required market ROE;

$\beta$ = adjusted beta coefficient of an individual security;

$r_f$ = the risk-free rate of return; and

$r_m$ = the required return on the market as a whole.

The ECAPM addresses the tendency of the "traditional" CAPM to underestimate the cost of equity for companies with low beta coefficients such as regulated utilities. In that regard, the ECAPM is not redundant to the use of adjusted betas in the traditional CAPM, but rather it recognizes the results of academic research indicating that the risk-return relationship is different (in essence, flatter) than estimated by the CAPM, meaning that the CAPM underestimates the cost of equity for companies with a beta less than 1.0 and overestimates the cost of equity for companies with a beta greater than 1.0.[28]

Consistent with my CAPM, my application of the ECAPM uses the forward-looking market risk premium estimates, the three yields on 30-year Treasury securities noted earlier as the risk-free rate, and the current *Bloomberg*, current *Value Line*, and long-term *Value Line* beta coefficients.

[28] *Id.,* at 191.

**Q. What are the results of your CAPM and ECAPM analyses?**

A. The results of my CAPM and ECAPM analyses are summarized in Figure 8, as well as presented in Exhibit A-14 (AEB-1), Schedule D-5, pages 6 through 14.

**Figure 8: CAPM and ECAPM Results**

| | 30-Year Treasury Bond Yield | | |
|---|---|---|---|
| | Current 30-Day Avg | Near-Term Projected | Longer-Term Projected |
| CAPM: | | | |
| Current *Value Line* Beta | 11.05% | 11.04% | 11.07% |
| Current Bloomberg Beta | 10.15% | 10.13% | 10.20% |
| Long-term Avg. *Value Line* Beta | 10.08% | 10.06% | 10.13% |
| ECAPM: | | | |
| Current *Value Line* Beta | 11.30% | 11.29% | 11.32% |
| Current Bloomberg Beta | 10.62% | 10.61% | 10.66% |
| Long-term Avg. *Value Line* Beta | 10.57% | 10.56% | 10.61% |

## C. BYRP Analysis

**Q. Please describe your BYRP analysis.**

A. In general terms, this approach is based on the fundamental principle that equity investors bear the residual risk associated with equity ownership and therefore require a premium over the return they would have earned as bondholders. In other words, because returns to equity holders have greater risk than returns to bondholders, equity holders require a higher return for that incremental risk. Thus, risk premium approaches estimate the cost of equity as the sum of the equity risk premium and the yield on a particular class of bonds. In my analysis, I use actual authorized returns for natural gas utilities as the historical measure of the cost of equity to determine the risk premium.

**Q. What is the fundamental relationship between the equity risk premium and interest rates?**

A. It is important to recognize both academic literature and market evidence indicating that the equity risk premium (as used in this approach) is inversely related to the level of interest rates (i.e. as interest rates increase, the equity risk premium decreases, and vice versa). Consequently, it is important to develop an analysis that: (1) reflects the inverse relationship between interest rates and the equity risk premium; and (2) relies on recent and expected market conditions. The analysis presented in Exhibit A-14 (AEB-1), Schedule D-5, pages 22 through 25, establishes that relationship using a regression of the risk premium as a function of Treasury bond yields. When the authorized ROEs serve as the measure of required equity returns and the long-term Treasury bond yield is defined as the relevant measure of interest rates, the risk premium is the difference between those two points.[29]

**Q. Is the BYRP analysis relevant to investors?**

A. Yes. Investors are aware of authorized ROEs in other jurisdictions and they consider those awards as a benchmark for a reasonable level of equity returns for utilities of comparable risk operating in other jurisdictions. Because my BYRP analysis is based on authorized ROEs for utility companies relative to corresponding Treasury yields, it provides relevant information to assess the return expectations of investors in the current interest rate environment.

[29] See, e.g., S. Keith Berry, "Interest Rate Risk and Utility Risk Premia during 1982-93*," Managerial and Decision Economics*, Vol. 19, No. 2, March 1998 (the author used a similar methodology, including using authorized ROEs as the relevant data source, and came to similar conclusions regarding the inverse relationship between risk premia and interest rates). See also, Robert S. Harris, "Using Analysts' Growth Forecasts to Estimate Shareholder Required Rates of Return," *Financial Management*, Spring 1986, at 66.

**Q. What did your BYRP analysis reveal?**

A. As shown in Figure 9, from January 1980 through September 2024, there was a strong negative relationship between risk premia and interest rates. To estimate that relationship, I conducted a regression analysis using the following equation:

$$RP = a + b(T) \qquad [6]$$

Where:

*RP* = Risk Premium (difference between allowed ROEs and the yield on 30-year U.S. Treasury bonds);

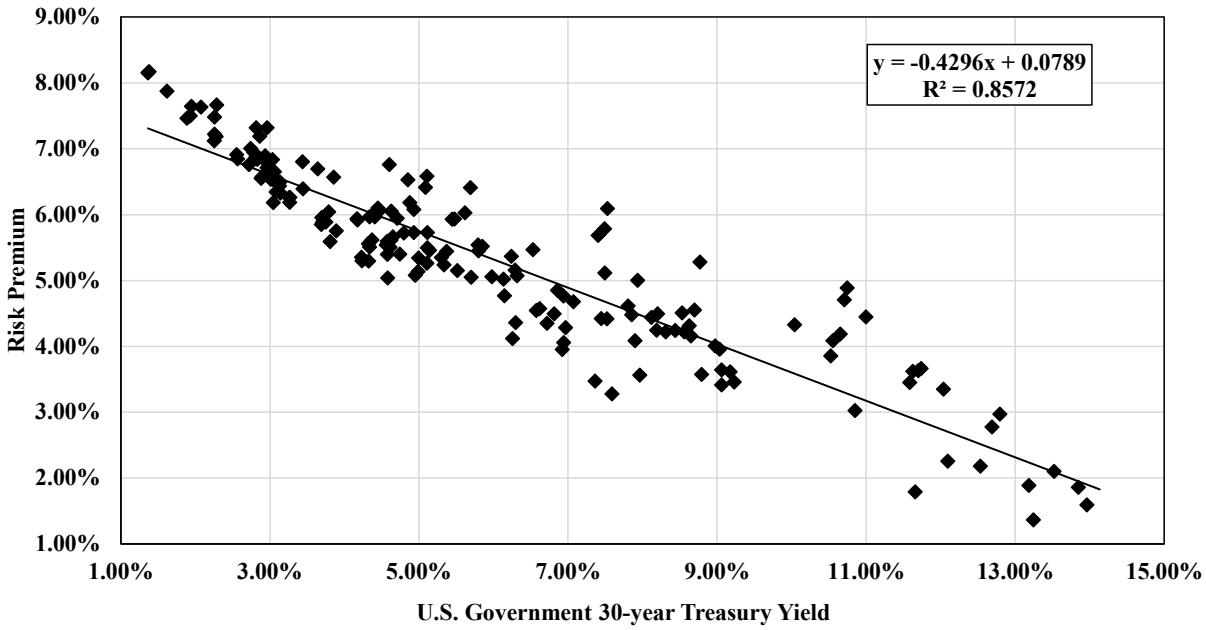
*a* = intercept term;

*b* = slope term; and

*T* = 30-year U.S. Treasury bond yield.

Data regarding authorized ROEs were derived from the natural gas utility rate cases over this period as reported by Regulatory Research Associates ("RRA").[30] The equation's coefficients are statistically significant at the 99.00% level.

**Figure 9: Risk Premium Regression Analysis**




[30] The data was screened to eliminate limited issue rider cases, transmission cases, and cases that were silent with respect to the authorized ROE.

**Q. What are the results of your BYRP analysis?**

A. Figure 10 presents the results of my BYRP analysis, which is also presented in more detail in Exhibit A-14, (AEB-1), Schedule D-5, page 22.

**Figure 10: BYRP Results**

| | 30-Year Treasury Bond Yield | | |
|---|---|---|---|
| | Current 30-Day Avg | Near-Term Projected | Longer-Term Projected |
| Bond Yield Risk Premium | 10.22% | 10.19% | 10.35% |

**Q. How did the results of the BYRP inform your recommended ROE for Consumers Energy?**

A. I have considered the results of the BYRP analysis in setting my recommended ROE for Consumers Energy. As noted above, investors consider the ROE determination by a regulator when assessing the risk of that company as compared to utilities of comparable risk operating in other jurisdictions. The BYRP analysis takes into account this comparison by estimating the return expectations of investors based on the current and past ROE awards of natural gas utilities across the U.S.

## VIII. REGULATORY AND BUSINESS RISKS

**Q. Do the results of the cost of equity analyses alone provide an appropriate estimate of the cost of equity for the Company?**

A. No. These results provide only a range of the appropriate estimate of the Company's cost of equity. Several additional factors must be considered when determining where the Company's cost of equity falls within the range of analytical results. These risk factors, discussed below, should be considered with respect to their overall effect on the Company's risk profile relative to the proxy group.

**A. Flotation Cost**

**Q. What are flotation costs?**

A. Flotation costs are the costs associated with the sale of new issues of common stock. These costs include out-of-pocket expenditures for preparation, filing, underwriting, and other issuance costs.

**Q. Why is it important to consider flotation costs in the allowed ROE?**

A. A regulated utility must have the opportunity to earn an ROE that is both competitive and compensatory to attract and retain new investors. To the extent that a company is denied the opportunity to recover prudently incurred flotation costs, actual returns will fall short of expected (or required) returns, thereby diluting equity share value.

**Q. Are flotation costs part of the utility's invested costs or part of the utility's expenses?**

A. Flotation costs are part of the invested costs of the utility, which are properly reflected on the balance sheet under "paid in capital." They are not current expenses, and, therefore, are not reflected on the income statement. Rather, like investments in rate base or the issuance costs of long-term debt, flotation costs are incurred over time. As a result, the great majority of a utility's flotation cost is incurred prior to the test year but remains part of the cost structure that exists during the test year and beyond, and as such, should be recognized for ratemaking purposes. Therefore, it is irrelevant whether an issuance occurs during the test year or is planned for the test year because failure to allow recovery of past flotation costs may deny Consumers Energy the opportunity to earn its required rate of return in the future.

**Q. Can you provide an example of why a flotation cost adjustment is necessary to compensate investors for the capital they have invested?**

A. Yes. Suppose CMS issues stock with a value of $100, and an equity investor invests $100 in CMS in exchange for that stock. Further suppose that, after paying the flotation costs associated with the equity issuance, which include fees paid to underwriters and attorneys, among others, CMS ends up with only $97 of issuance proceeds, rather than the $100 the investor contributed. CMS invests that $97 in plant used to serve its customers, which becomes part of rate base. Absent a flotation cost adjustment, the investor will thereafter earn a return on only the $97 invested in rate base, even though she contributed $100. Making a small flotation cost adjustment gives the investor a reasonable opportunity to earn the authorized return, rather than the lower return that results when the authorized return is applied to an amount less than what the investor contributed. This is consistent with basic ratemaking principles.

**Q. Is the date of CMS's last issued common equity important in the determination of flotation costs?**

A. No. As shown in Exhibit A-14 (AEB-1), Schedule D-5, page 26, CMS closed on equity issuances of approximately $298 million and $282 million (for a total of 55.78 million shares of common stock) in October 2004 and March 2005, respectively. The vintage of the issuance, however, is not particularly important because the investor suffers a shortfall in every year that she should have a reasonable opportunity to earn a return on the full amount of capital that she has contributed. Returning to my earlier example, the investor who contributed $100 is entitled to a reasonable opportunity to earn a return on $100 not only in the first year after the investment, but in every subsequent year in which she has

the $100 invested. Leaving aside depreciation, which is dealt with separately, there is no basis to conclude that the investor is entitled to earn a return on $100 in the first year after issuance, but thereafter is entitled to earn a return on only $97. As long as the $100 is invested, the investor should have a reasonable opportunity to earn a return on the entire amount.

**Q. Is the need to consider flotation costs eliminated because Consumers Energy is a wholly-owned subsidiary of CMS?**

A. No. Although Consumers Energy is a wholly-owned subsidiary of CMS, it is appropriate to consider flotation costs because wholly-owned subsidiaries receive equity capital from their parent and provide returns on the capital that roll up to the parent, which is designated to attract and raise capital based upon the returns of those subsidiaries. To deny recovery of issuance costs associated with the capital that is invested in the subsidiaries ultimately penalizes the investors that fund the utility operations and could inhibit the utility's ability to obtain new equity capital at a reasonable cost.

**Q. Is the need to consider flotation costs recognized by the academic and financial communities?**

A. Yes. The need to reimburse shareholders for the lost returns associated with equity issuance costs is recognized by the academic and financial communities in the same spirit that investors are reimbursed for the costs of issuing debt. This treatment is consistent with the philosophy of a fair rate of return. According to Dr. Shannon Pratt:

> Flotation costs occur when new issues of stock or debt are sold to the public. The firm usually incurs several kinds of flotation or transaction costs, which reduce the actual proceeds received by the firm. Some of these are direct out-of-pocket outlays, such as fees paid to underwriters, legal expenses, and prospectus preparation costs. Because of this

> reduction in proceeds, the firm's required returns on these proceeds equate to a higher return to compensate for the additional costs. Flotation costs can be accounted for either by amortizing the cost, thus reducing the cash flow to discount, or by incorporating the cost into the cost of capital. Because flotation costs are not typically applied to operating cash flow, one must incorporate them into the cost of capital.[31]

**Q. How did you calculate the flotation costs for CMS?**

A. My flotation cost calculation is based on the costs of issuing equity that were incurred by CMS in its two most recent common equity issuances. That flotation cost percentage is then applied to the proxy group in the DCF analysis to estimate the impact on the cost of equity associated with flotation costs. As shown in Exhibit A-14 (AEB-1), Schedule D-5, page 26, based on the flotation costs previously incurred by CMS, the average impact on the proxy group's cost of equity is 14 basis points (i.e. 0.14%).

**Q. Do your final cost of equity results include an adjustment for flotation cost recovery?**

A. No. While the final ROE results do not incorporate an explicit adjustment for flotation costs, I have considered the effect of flotation costs, along with the other risk factors present for the Company, in determining where, within the range of analytical results, my recommended ROE for the Company should fall.

## B. Capital Expenditures

**Q. What are the Company's projected capital expenditure requirements over the next few years?**

A. As of December 31, 2023, the Company had net gas utility plant of approximately $9.72 billion,[32] and the Company currently projects capital expenditures for 2025 through

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[31] Shannon P. Pratt, *Cost of Capital Estimation and Applications* (2nd ed. 2002), at 220-221.

[32] Exhibit A-2 (HLR-8), Schedule B-6, page 1.

2029 of approximately $6.00 billion,[33] which represent approximately 62% of its current net utility plant.

**Q. How do Consumers Energy's capital expenditure requirements compare to those of the proxy group companies?**

A. As shown Exhibit A-14 (AEB-1), Schedule D-5, page 27, I have calculated the ratio of expected capital expenditures to net utility plant for Consumers Energy and each of the companies in the proxy group by dividing each company's projected capital expenditures for the period from 2025 through 2029 by its total net utility plant as of December 31, 2023. As shown, Consumers Energy's ratio of capital expenditures as a percentage of net utility plant is lower than the median for the proxy group companies, however the capital expenditures still represent an extensive capital project relative to the total net plant utility.

**Q. How is the Company's risk profile affected by their substantial capital expenditure requirements?**

A. As with any utility faced with substantial capital expenditure requirements, the Company's risk profile may be adversely affected in two significant and related ways: (1) the heightened level of investment increases the risk of under-recovery or delayed recovery of the invested capital; and (2) an inadequate return would put downward pressure on key credit metrics.

**Q. Do credit rating agencies recognize the risks associated with significant capital expenditures?**

A. Yes. From a credit perspective, the additional pressure on cash flows associated with high levels of capital expenditures exerts corresponding pressure on credit metrics and,

[33] Exhibit A-42 (NPD-1), page 86.

therefore, credit ratings. To that point, S&P explains the importance of regulatory support for a significant amount of capital projects:

> When applicable, a jurisdiction's willingness to support large capital projects with cash during construction is an important aspect of our analysis. This is especially true when the project represents a major addition to rate base and entails long lead times and technological risks that make it susceptible to construction delays. Broad support for all capital spending is the most credit-sustaining. Support for only specific types of capital spending, such as specific environmental projects or system integrity plans, is less so, but still favorable for creditors. Allowance of a cash return on construction work-in-progress or similar ratemaking methods historically were extraordinary measures for use in unusual circumstances, but when construction costs are rising, cash flow support could be crucial to maintain credit quality through the spending program. Even more favorable are those jurisdictions that present an opportunity for a higher return on capital projects as an incentive to investors.[34]

Recently, S&P evaluated the capital expenditure trends in the utility sector, noting that the balance between operating with negative discretionary cash flow from operations offset by reliable access to capital markets for financing may be tested through ever-increasing capital expenditure requirements as a result of the transformation of the energy sector through the focus on low/no carbon generation, electrification, and the replacement of aging infrastructure:

> Some companies have been unable to support financial metrics consistent with former ratings as their discretionary cash flow deteriorated. This trend was a significant contributor to the sector seeing the median rating decline to 'BBB+' from 'A-' for the first time in 2022. What is less clear is whether or not management teams will take steps to forestall another step down in credit quality as high capital outlays persist. So far in 2023, we have not seen evidence that equity issuance is keeping pace with debt issuance to fill

[34] S&P Global Ratings, "Assessing U.S. Investor-Owned Utility Regulatory Environments," August 10, 2016, at 7.

> ever-deepening discretionary cash flow shortfalls, but time will tell.
>
> ***
>
> Despite the improvement in the economic outlook, we expect inflation, high interest rates, higher capital spending, and the strategic decision by many companies to operate with only minimal financial cushion from their downgrade thresholds to continue to pressure the industry's credit quality. We are cautious about the durability of the current stable ratings outlook given persistently high capital spending that now supports a trend of deterioration in discretionary cash flow. Without a commensurate focus on balance sheet preservation through equity support of discretionary cash flow deficits, limited financial cushions could give rise to another round of negative rating actions. The question then comes back to management priorities and financial policy decisions, or utilities may be faced with another step down in the median ratings. [35]

Therefore, to the extent that Consumers Energy's rates do not permit the opportunity to recover its capital investments on a regular and timely basis, the Company will face increased recovery risk and thus increased pressure on its credit metrics.

**Q. Does the Company currently have a capital tracking mechanism to recover the costs associated with its gas capital expenditures plan between rate cases?**

A. No. Consumers Energy currently has not requested approval to recover gas capital investment costs between rate cases utilizing a capital tracking mechanism. Therefore, Consumers Energy depends entirely on rate case filings for gas capital cost recovery. However, significant capital programs like Consumers Energy's generally receive cost recovery through infrastructure and capital trackers. As shown in Exhibit A-14 (AEB-1),

[35] S&P Global Ratings, "Record CapEx Fuels Growth Along With Credit Risk For North American Investor-Owned Utilities," September 12, 2023, at 5, 7-8.

Schedule D-5, page 29, approximately 71% of the companies in the proxy group currently have mechanisms for some form of capital cost recovery in place.

**Q. What are your conclusions regarding the effect of the Company's capital spending requirements on its risk profile and cost of capital?**

A. Even though Consumers Energy has lower projected capital expenditure programs relative to net utility plant of the proxy group over the next five years, the Company still has a significant capital spend program. Further, unlike a number of the operating subsidiaries of the proxy group, Consumers Energy does not currently have a capital tracking mechanism for gas capital investment. This results in greater risk for the Company than the proxy group, all else being equal.

### C. Regulatory Risk

**Q. How does the regulatory environment affect investors' risk assessments?**

A. The ratemaking process is premised on the principle that, for investors and companies to commit the capital needed to provide safe and reliable utility service, the subject utility must have the opportunity to recover the return of, and the market-required return on, invested capital. Regulatory commissions recognize that because utility operations are capital intensive, their decisions should enable the utility to attract capital at reasonable terms, and that doing so balances the long-term interests of investors and customers. Utilities must finance their operations and thus require the opportunity to earn a reasonable return on their invested capital to maintain their financial profiles. The Company is no exception. Therefore, the regulatory environment is one of the most important factors considered in both debt and equity investors' risk assessments.

From the perspective of debt investors, the authorized return should enable the utility to generate the cash flow needed to meet its near-term financial obligations, make the capital investments needed to maintain and expand its systems, and maintain the necessary levels of liquidity to fund unexpected events. This financial liquidity must be derived not only from internally generated funds, but also by efficient access to capital markets. Moreover, because fixed income investors have many investment alternatives, even within a given market sector, a utility's financial profile must be adequate on a relative basis to ensure its ability to attract capital under a variety of economic and financial market conditions.

Equity investors require that the authorized return be adequate to provide a risk-comparable return on the equity portion of the utility's capital investments. Because equity investors are the residual claimants on the utility's cash flows (i.e. the equity return is subordinate to interest payments), they are particularly concerned with the strength of regulatory support and its effect on future cash flows.

**Q. Do credit rating agencies consider regulatory risk in establishing a company's credit rating?**

A. Yes. Both S&P and Moody's consider the overall regulatory framework in establishing credit ratings. Moody's establishes credit ratings based on four key factors: (1) regulatory framework; (2) the ability to recover costs and earn returns; (3) diversification; and (4) financial strength, liquidity and key financial metrics. Of these criteria, regulatory framework and the ability to recover costs and earn returns are each given a broad rating

factor of 25.00%. Therefore, Moody's assigns regulatory risk a 50.00% weighting in the overall assessment of business and financial risk for regulated utilities.[36]

S&P also identifies the regulatory framework as an important factor in credit ratings for regulated utilities, stating: "we assess regulatory advantage because the influence of the regulatory framework and regime is of critical importance. It defines the environment in which a utility operates and has a significant bearing on a utility's financial performance."[37] S&P identifies four specific factors that it uses to assess the credit implications of the regulatory jurisdictions of investor-owned regulated utilities: (1) regulatory stability; (2) tariff-setting procedures and design; (3) financial stability; and (4) regulatory independence and insulation.[38]

**Q. How does the regulatory environment in which a utility operates affect its access to and cost of capital?**

A. The regulatory environment can significantly affect both the access to and cost of capital in several ways. First, the proportion and cost of debt capital available to utility companies are influenced by the rating agencies' assessment of the regulatory environment. As noted by Moody's, "[u]tility rates are set in a political/regulatory process rather than a competitive or free-market process; thus, the regulatory framework is a key determinant of the credit quality of a utility."[39] Moody's further highlighted the relevance of a stable and predictable regulatory environment to a utility's credit quality, noting: "[t]he regulatory framework is important because it provides the basis for decisions that affect utilities,

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[36] Moody's Investors Service, Rating Methodology: Regulated Electric and Gas Utilities, August 6, 2024, at 2.
[37] Standard & Poor's Global Ratings, "Sector-Specific Corporate Methodology," April 4, 2024, at 147.
[38] *Id*.
[39] Moody's Investors Service, Rating Methodology: Regulated Electric and Gas Utilities, August 6, 2024, at 8.

including rate-setting as well as the consistency and predictability of regulatory decision-making."[40]

**Q. Have you conducted an analysis to compare the cost recovery mechanisms of Consumers Energy to the cost recovery mechanisms approved in the jurisdictions in which the companies in your proxy group operate?**

A. Yes. I have evaluated the regulatory framework in Michigan based on three factors that are important in terms of providing a regulated utility a reasonable opportunity to earn its authorized ROE: (1) test year convention (i.e. forecast vs. historical); (2) use of rate design or other mechanisms that mitigate volumetric risk and stabilize revenue; and (3) prevalence of capital cost recovery between rate cases. Each are described below and are summarized in Exhibit A-14 (AEB-1), Schedule D-5, page 29.

> Test Year Convention: Consumers Energy uses a forecasted test year, and similarly, half of the utility operating subsidiaries of the companies in the proxy group also use either a fully forecasted or partially forecasted test year. Forecast test years have been relied on for several years and produce cost estimates that are more reflective of future costs, which results in more accurate recovery of incurred costs and mitigates the regulatory lag associated with historical test years. As Lowry, Hovde, Getachew, and Makos explain in their 2010 report, *Forward Test Years for US Electric Utilities*:
>
> > This report provides an in depth discussion of the test year issue. It includes the results of empirical research which explores why the unit costs of electric IOUs are rising and shows that utilities operating under forward test years realize higher returns on capital and have credit ratings that are materially better than those of utilities operating under historical test years. The research suggests that shifting to a future test year is a prime strategy for rebuilding utility credit ratings as insurance against an uncertain future.[41]

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[40] *Id*.

[41] M.N. Lowry, D. Hovde, L. Getachew, and M. Makos, Forward Test Years for US Electric Utilities, prepared for Edison Electric Institute, August 2010, at 1.

Volumetric Risk: Consumers Energy does not currently have protection against volumetric risk because the Company requested not to continue its revenue decoupling mechanism in the Company's last rate proceeding.[42] Approximately 92% of the utility operating subsidiaries of the proxy group companies have some form of revenue stabilization through either decoupling, formula-based rates, and/or straight-fixed variable rate design that allow them to break the link between customer usage and revenues.

Capital Cost Recovery: As previously mentioned, Consumers Energy does not have a capital tracking mechanism to recover gas capital investment costs between rate cases. However, approximately 71% of the utility operating subsidiaries of the proxy group companies have some form of capital cost recovery mechanism.

**Q. How does RRA evaluate the regulatory environment in each jurisdiction?**

A. RRA evaluates the regulatory environment from an investor perspective, considering the relative regulatory risk associated with ownership of securities issued by the companies that are regulated in each jurisdiction. RRA considers several factors that affect the regulatory process, including gubernatorial, legislative, and court activity; rate case decisions and other regulatory decisions; and information obtained through contact with commissioners, staff, utilities, and government outreach.

**Q. Has RRA provided recent commentary regarding its regulatory ranking for Michigan?**

A. In August 2024, RRA lowered its regulatory ranking of Michigan from "Above Average/3" to "Average/1," noting the following:

> While the jurisdiction remains more constructive than average from an investor viewpoint, ***the outcomes of certain recent rate proceedings could indicate a tightening in the regulatory climate***. RRA had placed the state on watch following a 2022 rate case decision in which the Michigan Public Service Commission (PSC) authorized DTE Electric Co. (DTE-E) an increase in rates that was less than 10% of that requested, but did not lower the ranking at that time. At the time RRA viewed the decisions to be an anomaly, as a

[42] MPSC Case No. U-21308, Direct Testimony of Laura M. Connolly, December 2022, at 13-14.

large part of the revenue requirement difference stemmed from reliance on a higher post-COVID sales forecast than the utility had used in its revenue requirement calculations. Even so, the company filed a new rate case less than three months later, asserting existing rates and projected electricity sales could not sustain its major capital investment program. Even though the outcome of the subsequent rate case was more constructive, DTE-E filed its third case in three years within four months (on March 28, 2024). The proceeding is pending and contends that current rates are not expected to provide it with adequate revenues to make necessary infrastructure investments while providing a reasonable opportunity to earn a fair return on equity. DTE-E is not the only company that has faced challenges in recent rate proceedings before the PSC. In a July 2, 2024 electric rate decision for Indiana Michigan Power Co., the commission authorized the company a rate increase that was about half what the company requested and kept its authorized ROE unchanged despite recent increases in interest rates. ***While the approved ROEs remain above prevailing industry averages, they compare less favorably to these averages, which have risen, albeit modestly, in recent periods***. The commission, nevertheless, does have several constructive practices have been in place: a streamlined rate case process; a framework for the utilization of forecast test years to reduce regulatory lag; and a framework that permits a cash return on certain construction work in progress, thereby reducing the uncertainty of cost recovery. Retail competition for electric generation is in place but is limited, and attempts to raise this limit have not been successful. Electric utilities have retained their generation assets, and customers who do not select a competitive supplier receive service on a regulated, traditional cost-of-service basis. Adjustment mechanisms are in place for fuel costs for customers served under bundled service. However, the courts have ruled against the authorization of revenue decoupling mechanisms for electric utilities. In the gas industry, the major local distribution companies have instituted programs that allow all retail customers to choose their gas supplier, and modest small-customer switching has occurred. The gas companies utilize periodic gas cost recovery mechanisms, and the PSC has authorized revenue decoupling mechanisms for certain gas utilities. Michigan's regulatory and political environments continue to support significant capital investments and

timely recovery of these costs. RRA now accords Michigan regulation an Average/1 ranking[43]

Additionally, Company witness Bleckman's direct testimony provides additional detail on the credit rating agencies' assessment of Michigan's regulatory environment.

**Q. What are your conclusions regarding the perceived risks related to the regulatory environment in Michigan?**

A. As discussed throughout this section of my testimony, both Moody's and S&P have identified the supportiveness of the regulatory environment as an important consideration in developing their overall credit ratings for regulated utilities. Considering the regulatory adjustment mechanisms, many of the companies in the proxy group have slightly more timely cost recovery between rate proceedings than Consumers Energy has in Michigan.

## IX. CONCLUSION AND RECOMMENDATION

**Q. What is your conclusion regarding a fair ROE for Consumers Energy?**

A. Figure 11 summarizes the results of my cost of equity analyses. Based on these results, the qualitative analyses presented in my direct testimony, the business and financial risks of Consumers Energy compared to the proxy group, and current and prospective conditions in capital markets, it is my view that an ROE of 10.25% is reasonable and would fairly balance the interests of customers and shareholders.

**Q. Will the capital structure and ROE authorized in this proceeding affect the Company's access to capital at reasonable rates?**

A. Yes. The level of earnings authorized by the Commission directly affects the Company's ability to fund its operations with internally generated funds. Both bond investors and

[43] Regulatory Research Associates, Profile of Michigan Public Service Commission, accessed August 6, 2024.

rating agencies expect a significant portion of ongoing capital investments to be financed with internally generated funds. In addition, it is important to recognize that because a utility's investment horizon is very long, investors require the assurance of a sufficiently high return to satisfy the long-term financing requirements of the assets placed into service. Those assurances, which often are measured by the relationship between internally generated cash flows and debt (or interest expense), depend quite heavily on the capital structure. Therefore, both the ROE and capital structure are very important to debt and equity investors, particularly given the capital market conditions discussed previously. Company witness Bleckman's direct testimony explains the effect of the Company's authorized ROE and Equity ratio on credit quality.

**Figure 11: Summary of Analytical Results**

***Constant Growth DCF***

| | Minimum Growth Rate | Average Growth Rate | Maximum Growth Rate |
|---|---|---|---|
| Mean Results: | | | |
| 30-Day Avg. Stock Price | 8.59% | 9.87% | 11.30% |
| 90-Day Avg. Stock Price | 8.79% | 10.06% | 11.50% |
| 180-Day Avg. Stock Price | 8.95% | 10.23% | 11.66% |
| Average | 8.78% | 10.05% | 11.49% |
| Median Results: | | | |
| 30-Day Avg. Stock Price | 8.48% | 9.83% | 11.33% |
| 90-Day Avg. Stock Price | 8.72% | 10.05% | 11.57% |
| 180-Day Avg. Stock Price | 8.86% | 10.17% | 11.71% |
| Average | 8.69% | 10.02% | 11.54% |

***CAPM / ECAPM / Bond Yield Risk Premium***

| | 30-Year Treasury Bond Yield | | |
|---|---|---|---|
| | Current 30-Day Avg | Near-Term Projected | Longer-Term Projected |
| CAPM: | | | |
| Current *Value Line* Beta | 11.05% | 11.04% | 11.07% |
| Current Bloomberg Beta | 10.15% | 10.13% | 10.20% |
| Long-term Avg. *Value Line* Beta | 10.08% | 10.06% | 10.13% |
| ECAPM: | | | |
| Current *Value Line* Beta | 11.30% | 11.29% | 11.32% |
| Current Bloomberg Beta | 10.62% | 10.61% | 10.66% |
| Long-term Avg. *Value Line* Beta | 10.57% | 10.56% | 10.61% |
| Bond Yield Risk Premium | 10.22% | 10.19% | 10.35% |

**Q. Does this conclude you direct testimony?**

A. Yes.

# ATTACHMENT A

Brattle

## PRINCIPAL

Boston 508.981.0866 Ann.Bulkley@brattle.com

With more than 25 years of experience in the energy industry, Ms. Bulkley specializes in regulatory economics for the electric and natural gas and water utility sectors, including valuation of regulated and unregulated utility assets, cost of capital, and capital structure issues.

Ms. Bulkley has extensive state and federal regulatory experience, and she has provided expert testimony on the cost of capital in nearly 100 regulatory proceedings before 32 state regulatory commissions and the Federal Energy Regulatory Commission (FERC).

In addition to her regulatory experience, Ms. Bulkley has provided valuation and appraisal services for a variety of purposes, including the sale or acquisition of utility assets, regulated ratemaking, ad valorem tax disputes, and other litigation purposes. In addition, she has experience in the areas of contract and business unit valuation, strategic alliances, market restructuring, and regulatory and litigation support.

Ms. Bulkley is a Certified General Appraiser licensed in the Commonwealth of Massachusetts and the State of New Hampshire.

Prior to joining Brattle, Ms. Bulkley was a Senior Vice President at an economic consultancy and held senior positions at several other consulting firms.

### AREAS OF EXPERTISE

- Regulatory Economics, Finance & Rates
- Regulatory Investigations & Enforcement
- Tax Controversy & Transfer Pricing
- Electricity Litigation & Regulatory Disputes
- M&A Litigation



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## EDUCATION

- **Boston University**
  MA in Economics
- **Simmons College**
  BA in Economics and Finance

## PROFESSIONAL EXPERIENCE

- **The Brattle Group (2022–Present)**
  Principal
- **Concentric Energy Advisors, Inc. (2002–2021)**
  Senior Vice President
  Vice President
  Assistant Vice President
  Project Manager
- **Navigant Consulting, Inc. (1997–2002)**
  Project Manager
- **Reed Consulting Group (1995-1997)**
  Consultant- Project Manager
- **Cahners Publishing Company (1995)**
  Economist

## SELECTED CONSULTING EXPERIENCE & EXPERT TESTIMONY

### REGULATORY ANALYSIS AND RATEMAKING

Have provided a range of advisory services relating to regulatory policy analysis and many aspects of utility ratemaking, with specific services including:

- Cost of capital and return on equity testimony, cost of service and rate design analysis and testimony, development of ratemaking strategies
- Development of merchant function exit strategies



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- Analysis and program development to address residual energy supply and/or provider of last resort obligations
- Stranded costs assessment and recovery
  Performance-based ratemaking analysis and design
- Many aspects of traditional utility ratemaking (e.g., rate design, rate base valuation)

## COST OF CAPITAL

Have provided expert testimony on the cost of capital and capital structure in nearly 100 regulatory proceedings before state and federal regulatory commissions in the United States.

## RATEMAKING

Have assisted several clients with analysis to support investor-owned and municipal utility clients in the preparation of rate cases. Sample engagements include:

- Assisted several investor-owned and municipal clients on cost allocation and rate design issues including the development of expert testimony supporting recommended rate alternatives.
- Worked with Canadian regulatory staff to establish filing requirements for a rate review of a newly regulated electric utility. Along with analyzing and evaluating rate application, attended hearings and conducted investigation of rate application for regulatory staff and prepared, supported, and defended recommendations for revenue requirements and rates for the company. Additionally, developed rates for gas utility for transportation program and ancillary services.

## VALUATION

Have provided valuation services to utility clients, unregulated generators, and private equity clients for a variety of purposes, including ratemaking, fair value, ad valorem tax, litigation and damages, and acquisition. Appraisal practices are consistent with the national standards established by the Uniform Standards of Professional Appraisal Practice.

Representative projects/clients have included:

- Prepared appraisals of electric utility transmission and distribution assets for ad valorem tax purposes.
- Prepared appraisals of hydroelectric generating facilities for ad valorem tax purposes.
- Conducted appraisals of fossil fuel generating facilities for ad valorem tax purposes.
- Conducted appraisals of generating assets for the purposes of unwinding sale-leaseback agreements.
- For a confidential utility client, prepared valuation of fossil and nuclear generation assets for financing purposes for regulated utility client.



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- Conducted a strategic review of the acquisition of nuclear generation assets. Review included the evaluation of the operating costs of the facilities and the long-term liabilities associated with the assets including the decommissioning of the assets.
- Prepared a valuation of a portfolio of generation assets for a large energy utility to be used for strategic planning purposes. Valuation approach included an income approach, a real options analysis, and a risk analysis.
- Assisted clients in the restructuring of NUG contracts through the valuation of the underlying assets. Performed analysis to determine the option value of a plant in a competitively priced electricity market following the settlement of the NUG contract.
- Prepared market valuations of several purchase power contracts for large electric utilities in the sale of purchase power contracts. Assignment included an assessment of the regional power market, analysis of the underlying purchase power contracts, and a traditional discounted cash flow valuation approach, as well as a risk analysis. Analyzed bids from potential acquirers using income and risk analysis approached. Prepared an assessment of the credit issues and value at risk for the selling utility.
- Prepared appraisal of a portfolio of generating facilities for a large electric utility to be used for financing purposes.
- Conducted a valuation of regulated utility assets for the fair value rate base estimate used in electric rate proceedings in Indiana.
- Prepared an appraisal of a fleet of fossil generating assets for a large electric utility to establish the value of assets transferred from utility property.
- Conducted due diligence on an electric transmission and distribution system as part of a buy-side due diligence team.
- Provided analytical support and prepared testimony regarding the valuation of electric distribution system assets in five communities in a condemnation proceeding.
- Prepared feasibility reports analyzing the expected net benefits resulting from municipal ownership of investor-owned utility operations.
- Prepared independent analyses of proposal for the proposed government condemnation of the investor-owned utilities in Maine and the formation of a public power district.
- Valued purchase power agreements in the transfer of assets to a deregulated electric market.

## STRATEGIC AND FINANCIAL ADVISORY SERVICES

Have assisted several clients across North America with analytically-based strategic planning, due diligence, and financial advisory services.

Representative projects include:



VERITEXT LEGAL SOLUTIONS

- Preparation of feasibility studies for bond issuances for municipal and district steam clients.
- Assisted in the development of a generation strategy for an electric utility. Analyzed various NERC regions to identify potential market entry points. Evaluated potential competitors and alliance partners. Assisted in the development of gas and electric price forecasts. Developed a framework for the implementation of a risk management program.
- Assisted clients in identifying potential joint venture opportunities and alliance partners. Contacted interviewed and evaluated potential alliance candidates based on company-established criteria for several LDCs and marketing companies. Worked with several LDCs and unregulated marketing companies to establish alliances to enter into the retail energy market. Prepared testimony in support of several merger cases and participated in the regulatory process to obtain approval for these mergers.
- Assisted clients in several buy-side due diligence efforts, providing regulatory insight and developing valuation recommendations for acquisitions of both electric and gas properties.



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## BULKLEY TESTIMONY LISTING

| SPONSOR | DATE | CASE/APPLICANT | DOCKET /CASE NO. | SUBJECT |
|---|---|---|---|---|
| **Arizona Corporation Commission** | | | | |
| Southwest Gas Corporation | 02/24 | Southwest Gas Corporation | Docket No. G-01551A-23-0341 | Return on Equity |
| UNS Electric | 11/22 | UNS Electric | Docket No. E-04204A-15-0251 | Return on Equity |
| Tucson Electric Power Company | 6/22 | Tucson Electric Power Company | Docket No. G-01933A-22-0107 | Return on Equity |
| Southwest Gas Corporation | 12/21 | Southwest Gas Corporation | Docket No. G-01551A-21-0368 | Return on Equity |
| Arizona Public Service Company | 10/19 | Arizona Public Service Company | Docket No. E-01345A-19-0236 | Return on Equity |
| Tucson Electric Power Company | 04/19 | Tucson Electric Power Company | Docket No. E-01933A-19-0028 | Return on Equity |
| Tucson Electric Power Company | 11/15 | Tucson Electric Power Company | Docket No. E-01933A-15-0322 | Return on Equity |
| UNS Electric | 05/15 | UNS Electric | Docket No. E-04204A-15-0142 | Return on Equity |
| UNS Electric | 12/12 | UNS Electric | Docket No. E-04204A-12-0504 | Return on Equity |
| **Arkansas Public Service Commission** | | | | |
| Oklahoma Gas and Electric Co | 10/21 | Oklahoma Gas and Electric Co | Docket No. D-18-046-FR | Return on Equity |
| Arkansas Oklahoma Gas Corporation | 10/13 | Arkansas Oklahoma Gas Corporation | Docket No. 13-078-U | Return on Equity |
| **California Public Utilities Commission** | | | | |
| PacifiCorp, d/b/a Pacific Power | 5/22 | PacifiCorp, d/b/a Pacific Power | Docket No. A-22-05-006 | Return on Equity |
| San Jose Water Company | 05/21 | San Jose Water Company | A2105004 | Return on Equity |
| **Colorado Public Utilities Commission** | | | | |



VERITEXT LEGAL SOLUTIONS

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| SPONSOR | DATE | CASE/APPLICANT | DOCKET /CASE NO. | SUBJECT |
|---|---|---|---|---|
| Public Service Company of Colorado | 01/24 | Public Service Company of Colorado | Docket No. 24AL-___G | Return on Equity |
| Public Service Company of Colorado | 11/22 | Public Service Company of Colorado | Docket No. 22AL-0530E | Return on Equity |
| Public Service Company of Colorado | 01/22 | Public Service Company of Colorado | Docket No. 22AL-0046G | Return on Equity |
| Public Service Company of Colorado | 07/21 | Public Service Company of Colorado | 21AL-0317E | Return on Equity |
| Public Service Company of Colorado | 02/20 | Public Service Company of Colorado | 20AL-0049G | Return on Equity |
| Public Service Company of Colorado | 05/19 | Public Service Company of Colorado | 19AL-0268E | Return on Equity |
| Public Service Company of Colorado | 01/19 | Public Service Company of Colorado | 19AL-0063ST | Return on Equity |
| Atmos Energy Corporation | 05/15 | Atmos Energy Corporation | Docket No. 15AL-0299G | Return on Equity |
| Atmos Energy Corporation | 04/14 | Atmos Energy Corporation | Docket No. 14AL-0300G | Return on Equity |
| Atmos Energy Corporation | 05/13 | Atmos Energy Corporation | Docket No. 13AL-0496G | Return on Equity |
| **Connecticut Public Utilities Regulatory Authority** | | | | |
| The Southern Connecticut Gas Company | 11/23 | The Southern Connecticut Gas Company | Docket No. 23-11-02 | Return on Equity |
| Connecticut Natural Gas Corporation | 11/23 | Connecticut Natural Gas Corporation | Docket No. 23-11-02 | Return on Equity |
| Connecticut Water Company | 10/23 | Connecticut Water Company | Docket No. 23-08-32 | Return on Equity |
| United Illuminating | 09/22 | United Illuminating | Docket No. 22-08-08 | Return on Equity |
| United Illuminating | 05/21 | United Illuminating | Docket No. 17-12-03RE11 | Return on Equity |
| Connecticut Water Company | 01/21 | Connecticut Water Company | Docket No. 20-12-30 | Return on Equity |
| Connecticut Natural Gas Corporation | 06/18 | Connecticut Natural Gas Corporation | Docket No. 18-05-16 | Return on Equity |



VERITEXT LEGAL SOLUTIONS

Brattle

| SPONSOR | DATE | CASE/APPLICANT | DOCKET /CASE NO. | SUBJECT |
|---|---|---|---|---|
| Yankee Gas Services Co. d/b/a Eversource Energy | 06/18 | Yankee Gas Services Co. d/b/a Eversource Energy | Docket No. 18-05-10 | Return on Equity |
| The Southern Connecticut Gas Company | 06/17 | The Southern Connecticut Gas Company | Docket No. 17-05-42 | Return on Equity |
| The United Illuminating Company | 07/16 | The United Illuminating Company | Docket No. 16-06-04 | Return on Equity |
| **Federal Energy Regulatory Commission** | | | | |
| Sea Robin Pipeline | 12/22 | Sea Robin Pipeline | Docket No. RP22-___ | Return on Equity |
| Northern Natural Gas Company | 07/22 | Northern Natural Gas Company | Docket No. RP22-___ | Return on Equity |
| Transwestern Pipeline Company, LLC | 07/22 | Transwestern Pipeline Company, LLC | Docket No. RP22-___ | Return on Equity |
| Florida Gas Transmission | 02/21 | Florida Gas Transmission | Docket No. RP21-441 | Return on Equity |
| TransCanyon | 01/21 | TransCanyon | Docket No. ER21-1065 | Return on Equity |
| Duke Energy | 12/20 | Duke Energy | Docket No. EL21-9-000 | Return on Equity |
| Wisconsin Electric Power Company | 08/20 | Wisconsin Electric Power Company | Docket No. EL20-57-000 | Return on Equity |
| Panhandle Eastern Pipe Line Company, LP | 10/19 | Panhandle Eastern Pipe Line Company, LP | Docket Nos. RP19-78-000 RP19-78-001 | Return on Equity |
| Panhandle Eastern Pipe Line Company, LP | 08/19 | Panhandle Eastern Pipe Line Company, LP | Docket Nos. RP19-1523 | Return on Equity |
| Sea Robin Pipeline Company LLC | 11/18 | Sea Robin Pipeline Company LLC | Docket# RP19-352-000 | Return on Equity |
| Tallgrass Interstate Gas Transmission | 10/15 | Tallgrass Interstate Gas Transmission | RP16-137 | Return on Equity |
| **Idaho Public Utilities Commission** | | | | |
| PacifiCorp d/b/a Rocky Mountain Power | 05/24 | PacifiCorp d/b/a Rocky Mountain Power | Case No. PAC-E-24-04 | Return on Equity |
| PacifiCorp d/b/a Rocky Mountain Power | 05/21 | PacifiCorp d/b/a Rocky Mountain Power | Case No. PAC-E-24-04 | Return on Equity |



VERITEXT LEGAL SOLUTIONS

Brattle

| SPONSOR | DATE | CASE/APPLICANT | DOCKET /CASE NO. | SUBJECT |
|---|---|---|---|---|
| Intermountain Gas Co | 12/22 | Intermountain Gas Co | C-INT-G-22-07 | Return on Equity |
| PacifiCorp d/b/a Rocky Mountain Power | 05/21 | PacifiCorp d/b/a Rocky Mountain Power | Case No. PAC-E-21-07 | Return on Equity |
| **Illinois Commerce Commission** | | | | |
| Illinois American Water | 01/24 | Illinois American Water | Docket No. 24-0097 | Return on Equity |
| Peoples Gas Light & Coke Company | 01/23 | Peoples Gas Light & Coke Company | D-23-0069 | Return on Equity |
| North Shore Gas Company | 01/23 | North Shore Gas Company | D-23-0068 | Return on Equity |
| Illinois American Water | 02/22 | Illinois American Water | Docket No. 22-0210 | Return on Equity |
| North Shore Gas Company | 02/21 | North Shore Gas Company | No. 20-0810 | Return on Equity |
| **Indiana Utility Regulatory Commission** | | | | |
| Ohio Valley Gas Corporation and Ohio Valley Gas, Inc. | 02/24 | Ohio Valley Gas Corporation and Ohio Valley Gas, Inc. | Cause No. 46011 | Return on Equity |
| Southern Indiana Gas and Electric Company d/b/a CenterPoint Energy Indiana South | 12/23 | Southern Indiana Gas and Electric Company d/b/a CenterPoint Energy Indiana South | IURC Cause No. 45990 | Return on Equity |
| Indiana Michigan Power Co. | 08/23 | Indiana Michigan Power Co. | IURC Cause No. 45933 | Return on Equity |
| Indiana American Water Company | 03/23 | Indiana and Michigan American Water Company | IURC Cause No. 45870 | Return on Equity |
| Indiana Michigan Power Co. | 07/21 | Indiana Michigan Power Co. | IURC Cause No. 45576 | Return on Equity |
| Indiana Gas Company Inc. | 12/20 | Indiana Gas Company Inc. | IURC Cause No. 45468 | Return on Equity |
| Southern Indiana Gas and Electric Company | 10/20 | Southern Indiana Gas and Electric Company | IURC Cause No. 45447 | Return on Equity |



VERITEXT LEGAL SOLUTIONS

Brattle

| SPONSOR | DATE | CASE/APPLICANT | DOCKET /CASE NO. | SUBJECT |
|---|---|---|---|---|
| Indiana and Michigan American Water Company | 09/18 | Indiana and Michigan American Water Company | IURC Cause No. 45142 | Return on Equity |
| Indianapolis Power and Light Company | 12/17 | Indianapolis Power and Light Company | Cause No. 45029 | Fair Value |
| Northern Indiana Public Service Company | 09/17 | Northern Indiana Public Service Company | Cause No. 44988 | Fair Value |
| Indianapolis Power and Light Company | 12/16 | Indianapolis Power and Light Company | Cause No.44893 | Fair Value |
| Northern Indiana Public Service Company | 10/15 | Northern Indiana Public Service Company | Cause No. 44688 | Fair Value |
| Indianapolis Power and Light Company | 09/15 | Indianapolis Power and Light Company | Cause No. 44576<br>Cause No. 44602 | Fair Value |
| Kokomo Gas and Fuel Company | 09/10 | Kokomo Gas and Fuel Company | Cause No. 43942 | Fair Value |
| Northern Indiana Fuel and Light Company, Inc. | 09/10 | Northern Indiana Fuel and Light Company, Inc. | Cause No. 43943 | Fair Value |
| **Iowa Department of Commerce Utilities Board** | | | | |
| Iowa-American Water Company | 04/24 | Iowa-American Water Company | Docket No. RPU-2024-000_ | Return on Equity |
| MidAmerican Energy Company | 06/23 | MidAmerican Energy Company | Docket No. RPU-2023-___ | Return on Equity |
| MidAmerican Energy Company | 01/22 | MidAmerican Energy Company | Docket No. RPU-2022-0001 | Return on Equity |
| Iowa-American Water Company | 08/20 | Iowa-American Water Company | Docket No. RPU-2020-0001 | Return on Equity |
| **Kansas Corporation Commission** | | | | |
| Evergy Kansas | 04/23 | Evergy Kansas | Docket No. 23-EKCE-775-RTS | Return on Equity |
| Atmos Energy Corporation | 08/15 | Atmos Energy Corporation | Docket No. 16-ATMG-079-RTS | Return on Equity |
| **Kentucky Public Service Commission** | | | | |



VERITEXT LEGAL SOLUTIONS

| SPONSOR | DATE | CASE/APPLICANT | DOCKET /CASE NO. | SUBJECT |
|---|---|---|---|---|
| Kentucky American Water Company | 06/23 | Kentucky American Water Company | Docket No. 2023-____ | Return on Equity |
| Kentucky American Water Company | 11/18 | Kentucky American Water Company | Docket No. 2018-00358 | Return on Equity |
| **Maine Public Utilities Commission** | | | | |
| Central Maine Power | 08/22 | Central Maine Power | Docket No. 2022-00152 | Return on Equity |
| Central Maine Power | 10/18 | Central Maine Power | Docket No. 2018-194 | Return on Equity |
| **Maryland Public Service Commission** | | | | |
| Maryland American Water Company | 06/18 | Maryland American Water Company | Case No. 9487 | Return on Equity |
| **Massachusetts Appellate Tax Board** | | | | |
| Hopkinton LNG Corporation | 03/20 | Hopkinton LNG Corporation | Docket No. | Valuation of LNG Facility |
| FirstLight Hydro Generating Company | 06/17 | FirstLight Hydro Generating Company | Docket No. F-325471<br>Docket No. F-325472<br>Docket No. F-325473<br>Docket No. F-325474 | Valuation of Electric Generation Assets |
| **Massachusetts Department of Public Utilities** | | | | |
| Massachusetts Electric Company<br>Nantucket Electric Company<br>d/b/a National Grid | 11/23 | Massachusetts Electric Company<br>Nantucket Electric Company<br>d/b/a National Grid | DPU 23-150 | Return on Equity |
| National Grid USA | 11/20 | Boston Gas Company | DPU 20-120 | Return on Equity |
| Berkshire Gas Company | 05/18 | Berkshire Gas Company | DPU 18-40 | Return on Equity |
| Unitil Corporation | 01/04 | Fitchburg Gas and Electric | DTE 03-52 | Integrated Resource Plan; Gas Demand Forecast |
| **Michigan Public Service Commission** | | | | |
| Upper Michigan Energy Resources Corporation | 05/24 | Upper Michigan Energy Resources Corporation | Case No. U-21541 | Return on Equity |



VERITEXT LEGAL SOLUTIONS

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| SPONSOR | DATE | CASE/APPLICANT | DOCKET /CASE NO. | SUBJECT |
|---|---|---|---|---|
| Michigan Gas Utilities Corporation | 03/24 | Michigan Gas Utilities Corporation | Case No. U-21540 | Return on Equity |
| Indiana Michigan Power Co. | 09/23 | Indiana Michigan Power Co. | Case No. U-21461 | Return on Equity |
| Michigan Gas Utilities Corporation | 03/23 | Michigan Gas Utilities Corporation | Case No. U-21366 | Return on Equity |
| Michigan Gas Utilities Corporation | 03/21 | Michigan Gas Utilities Corporation | Case No. U-20718 | Return on Equity |
| Wisconsin Electric Power Company | 12/11 | Wisconsin Electric Power Company | Case No. U-16830 | Return on Equity |
| **Michigan Tax Tribunal** | | | | |
| New Covert Generating Co., LLC. | 03/18 | The Township of New Covert Michigan | MTT Docket No. 000248TT and 16-001888-TT | Valuation of Electric Generation Assets |
| Covert Township | 07/14 | New Covert Generating Co., LLC. | Docket No. 399578 | Valuation of Electric Generation Assets |
| **Minnesota Public Utilities Commission** | | | | |
| ALLETE, Inc. d/b/a Minnesota Power | 11/23 | Allete, Inc. d/b/a Minnesota Power | D-E-015/GR-23-155 | Return on Equity |
| CenterPoint Energy Resources | 11/23 | CenterPoint Energy Resources | D-G-008/GR-23-173 | Return on Equity |
| Minnesota Energy Resources Corporation | 11/22 | Minnesota Energy Resources Corporation | Docket No. G011/GR-22-504 | Return on Equity |
| CenterPoint Energy Resources | 11/21 | CenterPoint Energy Resources | D-G-008/GR-21-435 | Return on Equity |
| ALLETE, Inc. d/b/a Minnesota Power | 11/21 | Allete, Inc. d/b/a Minnesota Power | D-E-015/GR-21-630 | Return on Equity |
| Otter Tail Power Company | 11/20 | Otter Tail Power Company | E017/GR-20-719 | Return on Equity |
| ALLETE, Inc. d/b/a Minnesota Power | 11/19 | Allete, Inc. d/b/a Minnesota Power | E015/GR-19-442 | Return on Equity |



VERITEXT LEGAL SOLUTIONS

Brattle

| SPONSOR | DATE | CASE/APPLICANT | DOCKET /CASE NO. | SUBJECT |
|---|---|---|---|---|
| CenterPoint Energy Resources Corporation d/b/a CenterPoint Energy Minnesota Gas | 10/19 | CenterPoint Energy Resources Corporation d/b/a CenterPoint Energy Minnesota Gas | G-008/GR-19-524 | Return on Equity |
| Great Plains Natural Gas Co. | 09/19 | Great Plains Natural Gas Co. | Docket No. G004/GR-19-511 | Return on Equity |
| Minnesota Energy Resources Corporation | 10/17 | Minnesota Energy Resources Corporation | Docket No. G011/GR-17-563 | Return on Equity |
| **Missouri Public Service Commission** | | | | |
| Ameren Missouri | 06/24 | Ameren Missouri | File No. ER-2024-0319 | Return on Equity |
| Evergy Missouri West | 02/24 | Evergy Missouri West | File No. ER-2024-0189 | Return on Equity |
| Ameren Missouri | 08/22 | Ameren Missouri | File No. ER-2022-0337 | Return on Equity |
| Missouri American Water Company | 07/22 | Missouri American Water Company | Case No. WR-2022-0303<br>Case No. SR-2022-0304 | Return on Equity |
| Evergy Missouri West | 01/22 | Evergy Missouri West | File No. ER-2022-0130 | Return on Equity |
| Evergy Missouri Metro | 01/22 | Evergy Missouri Metro | File No. ER-2022-0129 | Return on Equity |
| Ameren Missouri | 03/21 | Ameren Missouri | Docket No. ER-2021-0240<br>Docket No. GR-2021-0241 | Return on Equity |
| Missouri American Water Company | 06/20 | Missouri American Water Company | Case No. WR-2020-0344<br>Case No. SR-2020-0345 | Return on Equity |
| Missouri American Water Company | 06/17 | Missouri American Water Company | Case No. WR-17-0285<br>Case No. SR-17-0286 | Return on Equity |
| **Montana Public Service Commission** | | | | |



VERITEXT LEGAL SOLUTIONS

Brattle

| SPONSOR | DATE | CASE/APPLICANT | DOCKET /CASE NO. | SUBJECT |
|---|---|---|---|---|
| Montana-Dakota Utilities Co. | 11/22 | Montana-Dakota Utilities Co. | D2022.11.099 | Return on Equity |
| Montana-Dakota Utilities Co. | 06/20 | Montana-Dakota Utilities Co. | D2020.06.076 | Return on Equity |
| Montana-Dakota Utilities Co. | 09/18 | Montana-Dakota Utilities Co. | D2018.9.60 | Return on Equity |
| **Public Utilities Commission of Nevada** | | | | |
| Sierra Pacific Power Company d/b/a NV Energy | 02/24 | Sierra Pacific Power Company d/b/a NV Energy | 24-02026 | Return on Equity |
| Nevada Power Company d/b/a NV Energy | 06/23 | Nevada Power Company d/b/a NV Energy | 23-06007 | Return on Equity |
| Nevada Power Company d/b/a NV Energy | 03/23 | Nevada Power Company d/b/a NV Energy | 22-03028 | Merger benefits |
| **New Hampshire - Board of Tax and Land Appeals** | | | | |
| Liberty Utilities (EnergyNorth Natural Gas) | 07/23 | Liberty Utilities (EnergyNorth Natural Gas) | Docket No. DG 23-067 | Return on Equity |
| Liberty Utilities (Granite State Electric) | 05/23 | Liberty Utilities (Granite State Electric) | Docket No. DE 23-039 | Return on Equity |
| Public Service Company of New Hampshire d/b/a Eversource Energy | 11/19<br>12/19 | Public Service Company of New Hampshire d/b/a Eversource Energy | Master Docket No. 28873-14-15-16-17PT | Valuation of Utility Property and Generating Assets |
| **New Hampshire Public Utilities Commission** | | | | |
| Public Service Company of New Hampshire | 05/19 | Public Service Company of New Hampshire | DE-19-057 | Return on Equity |
| **New Hampshire-Merrimack County Superior Court** | | | | |
| Northern New England Telephone Operations, LLC d/b/a FairPoint Communications, NNE | 04/18 | Northern New England Telephone Operations, LLC d/b/a FairPoint Communications, NNE | 220-2012-CV-1100 | Valuation of Utility Property |



VERITEXT LEGAL SOLUTIONS

Brattle

| SPONSOR | DATE | CASE/APPLICANT | DOCKET /CASE NO. | SUBJECT |
|---|---|---|---|---|
| **New Hampshire-Rockingham Superior Court** | | | | |
| Eversource Energy | 05/18 | Public Service Commission of New Hampshire | 218-2016-CV-00899<br>218-2017-CV-00917 | Valuation of Utility Property |
| **New Jersey Board of Public Utilities** | | | | |
| New Jersey American Water Company, Inc. | 02/24 | New Jersey American Water Company, Inc. | WR2401056 | Return on Equity |
| Elizabethtown Gas Company | 2/24 | Elizabethtown Gas Company | GR24020158 | Return on Equity |
| Public Service Electric and Gas Company | 12/23 | Public Service Electric and Gas Company | ER23120924<br>GR23120925 | Return on Equity |
| New Jersey American Water Company, Inc. | 01/22 | New Jersey American Water Company, Inc. | WR22010019 | Return on Equity |
| Public Service Electric and Gas Company | 10/20 | Public Service Electric and Gas Company | EO18101115 | Return on Equity |
| New Jersey American Water Company, Inc. | 12/19 | New Jersey American Water Company, Inc. | WR19121516 | Return on Equity |
| Public Service Electric and Gas Company | 04/19 | Public Service Electric and Gas Company | EO18060629<br>GO18060630 | Return on Equity |
| Public Service Electric and Gas Company | 02/18 | Public Service Electric and Gas Company | GR17070776 | Return on Equity |
| Public Service Electric and Gas Company | 01/18 | Public Service Electric and Gas Company | ER18010029<br>GR18010030 | Return on Equity |
| **New Mexico Public Regulation Commission** | | | | |
| Southwestern Public Service Company | 07/19 | Southwestern Public Service Company | 19-00170-UT | Return on Equity |
| Southwestern Public Service Company | 10/17 | Southwestern Public Service Company | Case No. 17-00255-UT | Return on Equity |
| Southwestern Public Service Company | 12/16 | Southwestern Public Service Company | Case No. 16-00269-UT | Return on Equity |
| Southwestern Public Service Company | 10/15 | Southwestern Public Service Company | Case No. 15-00296-UT | Return on Equity |



VERITEXT LEGAL SOLUTIONS

| SPONSOR | DATE | CASE/APPLICANT | DOCKET /CASE NO. | SUBJECT |
|---|---|---|---|---|
| Southwestern Public Service Company | 06/15 | Southwestern Public Service Company | Case No. 15-00139-UT | Return on Equity |
| **New York State Department of Public Service** | | | | |
| Liberty Utilities (New York Water) | 5/23 | Liberty Utilities (New York Water) | Case 23-W-0235 | Return on Equity |
| New York State Electric and Gas Company<br><br>Rochester Gas and Electric | 05/22 | New York State Electric and Gas Company<br><br>Rochester Gas and Electric | 22-E-0317<br>22-G-0318<br>22-E-0319<br>22-G-0320 | Return on Equity |
| Corning Natural Gas Corporation | 07/21 | Corning Natural Gas Corporation | Case No. 21-G-0394 | Return on Equity |
| Central Hudson Gas and Electric Corporation | 08/20 | Central Hudson Gas and Electric Corporation | Electric 20-E-0428<br>Gas 20-G-0429 | Return on Equity |
| Niagara Mohawk Power Corporation | 07/20 | National Grid USA | Case No. 20-E-0380<br>20-G-0381 | Return on Equity |
| Corning Natural Gas Corporation | 02/20 | Corning Natural Gas Corporation | Case No. 20-G-0101 | Return on Equity |
| New York State Electric and Gas Company<br><br>Rochester Gas and Electric | 05/19 | New York State Electric and Gas Company<br><br>Rochester Gas and Electric | 19-E-0378<br>19-G-0379<br>19-E-0380<br>19-G-0381 | Return on Equity |
| Brooklyn Union Gas Company d/b/a National Grid NY<br>KeySpan Gas East Corporation d/b/a National Grid | 04/19 | Brooklyn Union Gas Company d/b/a National Grid NY<br>KeySpan Gas East Corporation d/b/a National Grid | 19-G-0309<br>19-G-0310 | Return on Equity |
| Central Hudson Gas and Electric Corporation | 07/17 | Central Hudson Gas and Electric Corporation | Electric 17-E-0459<br>Gas 17-G-0460 | Return on Equity |
| Niagara Mohawk Power Corporation | 04/17 | National Grid USA | Case No. 17-E-0238<br>17-G-0239 | Return on Equity |
| Corning Natural Gas Corporation | 06/16 | Corning Natural Gas Corporation | Case No. 16-G-0369 | Return on Equity |



VERITEXT LEGAL SOLUTIONS

| SPONSOR | DATE | CASE/APPLICANT | DOCKET /CASE NO. | SUBJECT |
|---|---|---|---|---|
| National Fuel Gas Company | 04/16 | National Fuel Gas Company | Case No. 16-G-0257 | Return on Equity |
| KeySpan Energy Delivery | 01/16 | KeySpan Energy Delivery | Case No. 15-G-0058<br>Case No. 15-G-0059 | Return on Equity |
| New York State Electric and Gas Company<br>Rochester Gas and Electric | 05/15 | New York State Electric and Gas Company<br>Rochester Gas and Electric | Case No. 15-E-0283<br>Case No. 15-G-0284<br>Case No. 15-E-0285<br>Case No. 15-G-0286 | Return on Equity |
| **North Dakota Public Service Commission** | | | | |
| Otter Tail Power Company | 11/23 | Otter Tail Power Company | Case No. PU-23-___ | Return on Equity |
| Montana-Dakota Utilities Co. | 11/23 | Montana-Dakota Utilities Co. | Case No. PU-23-___ | Return on Equity |
| Montana-Dakota Utilities Co. | 05/22 | Montana-Dakota Utilities Co. | C-PU-22-194 | Return on Equity |
| Montana-Dakota Utilities Co. | 08/20 | Montana-Dakota Utilities Co. | C-PU-20-379 | Return on Equity |
| Northern States Power Company | 12/12 | Northern States Power Company | C-PU-12-813 | Return on Equity |
| Northern States Power Company | 12/10 | Northern States Power Company | C-PU-10-657 | Return on Equity |
| **Oklahoma Corporation Commission** | | | | |
| Oklahoma Gas & Electric | 12/23 | Oklahoma Gas & Electric | Cause No. PUD2023-000087 | Return on Equity |
| Oklahoma Gas & Electric | 12/21 | Oklahoma Gas & Electric | Cause No. PUD 202100164 | Return on Equity |
| Arkansas Oklahoma Gas Corporation | 01/13 | Arkansas Oklahoma Gas Corporation | Cause No. PUD 201200236 | Return on Equity |
| **Oregon Public Service Commission** | | | | |
| PacifiCorp d/b/a Pacific Power & Light | 02/24 | PacifiCorp d/b/a Pacific Power & Light | Docket No. UE-433 | Return on Equity |
| PacifiCorp d/b/a Pacific Power & Light | 03/22 | PacifiCorp d/b/a Pacific Power & Light | Docket No. UE-399 | Return on Equity |



VERITEXT LEGAL SOLUTIONS

Brattle

| SPONSOR | DATE | CASE/APPLICANT | DOCKET /CASE NO. | SUBJECT |
|---|---|---|---|---|
| PacifiCorp d/b/a Pacific Power & Light | 02/20 | PacifiCorp d/b/a Pacific Power & Light | Docket No. UE-374 | Return on Equity |
| **Pennsylvania Public Utility Commission** | | | | |
| American Water Works Company Inc. | 11/23 | Pennsylvania-American Water Company | Docket No. R-2023-3043189 (water) Docket No. R-2023-3043190 (wastewater) | Return on Equity |
| American Water Works Company Inc. | 04/22 | Pennsylvania-American Water Company | Docket No. R-2020-3031672 (water) Docket No. R-2020-3031673 (wastewater) | Return on Equity |
| American Water Works Company Inc. | 04/20 | Pennsylvania-American Water Company | Docket No. R-2020-3019369 (water) Docket No. R-2020-3019371 (wastewater) | Return on Equity |
| American Water Works Company Inc. | 04/17 | Pennsylvania-American Water Company | Docket No. R-2017-2595853 | Return on Equity |
| **South Dakota Public Utilities Commission** | | | | |
| MidAmerican Energy Company | 05/22 | MidAmerican Energy Company | D-NG22-005 | Return on Equity |
| Northern States Power Company | 06/14 | Northern States Power Company | Docket No. EL14-058 | Return on Equity |
| **Texas Public Utility Commission** | | | | |
| CenterPoint Energy Houston | 03/24 | CenterPoint Energy Houston | D-56211 | Return on Equity |
| AEP Texas | 02/24 | AEP Texas | D-56165 | Return on Equity |
| Entergy Texas, Inc. | 07/22 | Entergy Texas, Inc. | D-53719 | Return on Equity |
| Southwestern Public Service Commission | 08/19 | Southwestern Public Service Commission | Docket No. D-49831 | Return on Equity |
| Southwestern Public Service Company | 01/14 | Southwestern Public Service Company | Docket No. 42004 | Return on Equity |
| **Texas Railroad Commission** | | | | |



VERITEXT LEGAL SOLUTIONS

Brattle

| SPONSOR | DATE | CASE/APPLICANT | DOCKET /CASE NO. | SUBJECT |
|---|---|---|---|---|
| CenterPoint Energy Entex and CenterPoint Energy Texas Gas | 10/23 | CenterPoint Energy Entex and CenterPoint Energy Texas Gas | 2023 Texas Division Rate Case Case No. OS-23-00015513 | Return on Equity |
| **Utah Public Service Commission** | | | | |
| PacifiCorp d/b/a Rocky Mountain Power | 06/24 | PacifiCorp d/b/a Rocky Mountain Power | Docket No. 24-035-04 | Return on Equity |
| PacifiCorp d/b/a Rocky Mountain Power | 05/20 | PacifiCorp d/b/a Rocky Mountain Power | Docket No. 20-035-04 | Return on Equity |
| **Virginia State Corporation Commission** | | | | |
| Virginia American Water Company, Inc. | 11/23 | Virginia American Water Company, Inc. | Docket No. PUR-2023-00194 | Return on Equity |
| Virginia American Water Company, Inc. | 11/21 | Virginia American Water Company, Inc. | Docket No. PUR-2021-00255 | Return on Equity |
| Virginia American Water Company, Inc. | 11/18 | Virginia American Water Company, Inc. | Docket No. PUR-2018-00175 | Return on Equity |
| **Washington Utilities Transportation Commission** | | | | |
| Cascade Natural Gas Corporation | 03/24 | Cascade Natural Gas Corporation | Docket No. UG-240008 | Return on Equity |
| Puget Sound Energy Inc. | 02/24 | Puget Sound Energy Inc. | Docket No. UE-240004 UG-240005 | Return on Equity |
| PacifiCorp d/b/a Pacific Power & Light | 03/23 | PacifiCorp d/b/a Pacific Power & Light | Docket No. UE-230172 | Return on Equity |
| Cascade Natural Gas Corporation | 06/20 | Cascade Natural Gas Corporation | Docket No. UG-200568 | Return on Equity |
| PacifiCorp d/b/a Pacific Power & Light | 12/19 | PacifiCorp d/b/a Pacific Power & Light | Docket No. UE-191024 | Return on Equity |
| Cascade Natural Gas Corporation | 04/19 | Cascade Natural Gas Corporation | Docket No. UG-190210 | Return on Equity |
| **West Virginia Public Service Commission** | | | | |



VERITEXT LEGAL SOLUTIONS

| SPONSOR | DATE | CASE/APPLICANT | DOCKET /CASE NO. | SUBJECT |
|---|---|---|---|---|
| West Virginia American Water Company | 05/23 | West Virginia American Water Company | Case No. 23-0383-W-42T | Return on Equity |
| West Virginia American Water Company | 04/21 | West Virginia American Water Company | Case No. 21-02369-W-42T | Return on Equity |
| West Virginia American Water Company | 04/18 | West Virginia American Water Company | Case No. 18-0573-W-42T<br>Case No. 18-0576-S-42T | Return on Equity |
| **Wisconsin Public Service Commission** | | | | |
| Wisconsin Power and Light | 04/24 | Wisconsin Power and Light | Docket No. 6680-UR-128 | Return on Equity |
| Wisconsin Electric Power Company and Wisconsin Gas LLC | 04/24 | Wisconsin Electric Power Company and Wisconsin Gas LLC | Docket No. 05-UR-111 | Return on Equity |
| Wisconsin Power and Light | 05/23 | Wisconsin Power and Light | Docket No. 6680-UR-124 | Return on Equity |
| Wisconsin Electric Power Company and Wisconsin Gas LLC | 04/22 | Wisconsin Electric Power Company and Wisconsin Gas LLC | Docket No. 05-UR-110 | Return on Equity |
| Wisconsin Public Service Corp. | 04/22 | Wisconsin Public Service Corp. | 6690-UR-127 | Return on Equity |
| Alliant Energy | | Alliant Energy | | Return on Equity |
| Wisconsin Electric Power Company and Wisconsin Gas LLC | 03/19 | Wisconsin Electric Power Company and Wisconsin Gas LLC | Docket No. 05-UR-109 | Return on Equity |
| Wisconsin Public Service Corp. | 03/19 | Wisconsin Public Service Corp. | 6690-UR-126 | Return on Equity |
| **Wyoming Public Service Commission** | | | | |
| PacifiCorp d/b/a Rocky Mountain Power | 08/24 | PacifiCorp d/b/a Rocky Mountain Power | Docket No. 20000-671-ER-24 | Return on Equity |
| PacifiCorp d/b/a Rocky Mountain Power | 02/23 | PacifiCorp d/b/a Rocky Mountain Power | Docket No. 20000-633-ER-23 | Return on Equity |
| PacifiCorp d/b/a Rocky Mountain Power | 03/20 | PacifiCorp d/b/a Rocky Mountain Power | Docket No. 20000-578-ER-20 | Return on Equity |



VERITEXT LEGAL SOLUTIONS

| SPONSOR | DATE | CASE/APPLICANT | DOCKET /CASE NO. | SUBJECT |
|---|---|---|---|---|
| Montana-Dakota Utilities Co. | 05/19 | Montana-Dakota Utilities Co. | 30013-351-GR-19 | Return on Equity |

CERTIFICATIONS/ACCREDITATIONS

Certified General Appraiser, licensed in the Commonwealth of Massachusetts



VERITEXT LEGAL SOLUTIONS

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

| | | |
|---|---|---|
| In the matter of the application of<br>**CONSUMERS ENERGY COMPANY**<br>for authority to increase its rates for the<br>distribution of natural gas and for other relief. | )<br>)<br>)<br>)<br>) | Case No. U-21806 |

**REBUTTAL TESTIMONY**

**OF**

**ANN E. BULKLEY**

**ON BEHALF OF**

**CONSUMERS ENERGY COMPANY**

May 2025

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## I. INTRODUCTION

**Q. Please state your name and business address.**

A. My name is Ann E. Bulkley. My business address is One Beacon Street, Suite 2600, Boston, Massachusetts 02108. I am a Principal at The Brattle Group ("Brattle"), a consulting firm that advises clients on regulatory finance and ratemaking issues.

**Q. Are you the same Ann E. Bulkley that previously filed direct testimony in this proceeding?**

A. Yes. I previously submitted direct testimony before the Michigan Public Service Commission ("MPSC" or the "Commission") in this proceeding on behalf of Consumers Energy Company ("Consumers Energy" or the "Company").

**Q. What is the purpose of your rebuttal testimony?**

A. The purpose of my rebuttal testimony is to respond to the issues raised in the testimonies of Kirk D. Megginson on behalf of the Commission Staff ("Staff"),[1] Sebastian Coppola on behalf of the Attorney General,[2] Matthew J. Bandyk on behalf of Citizens Utility Board of Michigan ("CUB"),[3] and Christopher Walters on behalf of the Association of Businesses Advocating Tariff Equity ("ABATE"),[4] regarding the just and reasonable return on equity ("ROE") for the Company in this proceeding. To the extent that I do not address a

[1] Michigan Public Service Commission, Case No. U-21806, Testimony of Kirk D. Megginson, April 23, 2025 ("Megginson Direct").

[2] Michigan Public Service Commission, Case No. U-21806, Testimony of Sebastian Coppola, April 23, 2025 ("Coppola Direct").

[3] Michigan Public Service Commission, Case No. U-21806, Testimony of Matthew J. Bandyk, April 23, 2025 ("Bandyk Direct").

[4] Michigan Public Service Commission, Case No. U-21806, Testimony of Christopher W. Walters, April 23, 2025 ("Walters Direct").

particular issue raised by these witnesses in my rebuttal testimony should not be viewed as acceptance of that issue.

**Q. Are you sponsoring any exhibits in support of your rebuttal testimony?**

A. I am sponsoring the following exhibits:

Exhibit A-127 (AEB-2) Cost of Common Shareholder's Equity; and

Exhibit A-128 (AEB-3) Jurisdictions Using ECAPM.

**Q. Was this exhibit prepared by you or under your supervision?**

A. Yes.

**Q. Have you updated the cost of equity analyses that you presented in your direct testimony to reflect current market conditions?**

A. Yes. As discussed in more detail herein, I have updated my cost of equity analyses based on market data through April 30, 2025. These results provide continual support for my recommended ROE range of 10.25% to 11.25% and the Company's requested ROE of 10.25%. While the analytical results of the cost of equity estimation models provide a starting point, I continue to base my recommendation on consideration of not only the results of multiple cost of equity models, but also other factors, including capital market conditions, the capital attraction and comparable return standards, and Company-specific risks.

**Q. How is the remainder of your rebuttal testimony organized?**

A. The remainder of my rebuttal testimony is organized as follows:

- Section II provides a summary and overview of my rebuttal testimony and the important factors to be considered in establishing the authorized ROE for the Company.

- Section III provides cost of equity analyses based on market data as of April 25, 2025.

- Section IV discusses the changes in capital market conditions since my direct testimony and their effect on the cost of equity and authorized ROEs for comparable utilities nationwide relative to the witnesses' ROE recommendations in this proceeding.

- Section V provides my response to the issues raised by the parties regarding the proxy group.

- Section VI provides my response to the issues raised by the parties regarding the Discounted Cash Flow ("DCF") model.

- Section VII provides my response to the issues raised by the parties regarding the Capital Asset Pricing Model ("CAPM") analysis.

- Section VIII provides my response to the issues raised by the parties regarding the Empirical CAPM ("ECAPM") analysis.

- Section IX provides my response to the issues raised by the parties regarding the Bond Yield Plus Risk Premium analysis.

- Section X provides the adjusted results of the cost of equity analyses of Mr. Megginson, Mr. Coppola, Mr. Bandyk, and Mr. Walters based on the issues that I have identified with their respective analyses.

- Section XI provides my response to the issues raised by the parties regarding the Company's business risks.

## II. SUMMARY OF ANALYSES AND CONCLUSIONS

**Q. What factors should be considered in evaluating the results of the cost of equity analyses and establishing the authorized ROE?**

A. The primary factors that should be considered are: (1) the importance of providing a return that is comparable to returns on alternative investments with commensurate risk; (2) the need for a return that supports a utility's ability to attract needed capital at reasonable terms; (3) the effect of current and expected capital market conditions; and (4) achieving a reasonable balance between the interests of investors and customers.

**Q. Please summarize the ROE recommendations of the parties in this proceeding.**

A. Figure 1 below summarizes the results of the cost of equity analyses presented by Mr. Megginson, Mr. Coppola, Mr. Bandyk, and Mr. Walters in this proceeding and each of their final ROE recommendations. As shown, the ROE recommendations of Mr. Megginson and Mr. Coppola are 9.75%, Mr. Bandyk recommends 9.24%, and Mr. Walters recommends 9.45%. Despite a significant increase in interest rates since the Company's last rate proceeding suggesting a higher overall cost of capital, all intervening witnesses recommend an ROE for the Company lower than the Company's currently authorized ROE of 9.90 percent. None of their recommendations are reasonable or appropriate based on changes in the cost of equity as reflected in current market conditions and the Company's overall risk profile.

**Figure 1: Summary of Cost of Equity Analyses Results and ROE Recommendations of Mr. Megginson, Mr. Coppola, Mr. Bandyk, and Mr. Walters**

| Methods | Megginson | Coppola | Bandyk | Walters |
|---|---|---|---|---|
| DCF | | | | |
| Constant DCF | 9.40% | 9.11% | - | 8.38-8.70% and 10.74%-13.54%[5] |
| Two-Stage DCF | - | - | 9.22% | - |
| Multi-Stage DCF | - | - | - | 8.47%-9.26% |
| CAPM | 8.25%-9.93% | 10.66% | 7.95% | 8.72%-10.74% |
| Risk Premium | 9.46%-9.72% | 9.20% | - | 9.73%-10.23% |
| Current Authorized ROE | - | - | 9.90% | - |
| Recommended ROE Range | 9.25%-10.25% | - | - | 9.00%-9.90% |
| **Recommended ROE** | **9.75%** | **9.75%** | **9.24%** | **9.45%** |

[5] Mr. Walters's results of 8.37% - 8.70% use a "sustainable growth" rate, and the results of 10.74% – 13.54% use analyst earnings growth projections.

**Q. What are your key conclusions and recommendations regarding the appropriate ROE for the Company?**

A. Nothing in the direct testimonies of Mr. Megginson, Mr. Coppola, Mr. Bandyk, or Mr. Walters has caused me to change my conclusions or recommendations. My key conclusions regarding a reasonable ROE for the Company in this proceeding are as follows:

**Cost of Equity**

- Updated cost of equity analyses based on data through April 25, 2025 continue to support the reasonableness of the Company's proposed ROE of 10.25%.
- Changes in market conditions and heightened uncertainty in the macro environment support a higher ROE than the Company's last proceeding, and Mr. Megginson, Mr. Coppola, Mr. Bandyk, and Mr. Walters do not adequately consider current capital market conditions.
- Mr. Bandyk recommends an ROE that is more than a *65-basis point decrease* relative to the Company's currently authorized ROE, which is primarily a function of his CAPM estimate that is substantially below any authorized ROE for a natural gas or electric utility since at least 1980.
- When reasonable adjustments are reflected to the cost of equity analyses prepared by Mr. Megginson, Mr. Coppola, Mr. Bandyk, and Mr. Walters to update and correct their analyses, it demonstrates that the Company's proposed ROE is reasonable.
    - The adjusted results of Mr. Megginson's, Mr. Coppola's, Mr. Bandyk's and Mr. Walters's analyses indicate a cost of equity in the range of 10.50% to 10.70%, which is higher than the Company's proposed ROE of 10.25%.
- There is no basis to Mr. Bandyk's claim that regulators have incorrectly authorized ROEs substantially higher than the cost of equity for decades.
- No intervening witness has independently evaluated the comparative risk of the Company relative to their respective proxy groups. Therefore, there is no basis to conclude that the risk factors that I evaluated in my direct testimony should not be considered.

## III. COST OF EQUITY ANALYSES

**Q. Have you prepared cost of equity analyses to support your rebuttal testimony?**

A. Yes. I updated the results of the cost of equity analyses conducted in my direct testimony based on market data through April 25, 2025, to rebut the outdated cost of equity analyses provided by Mr. Megginson, Mr. Coppola, Mr. Bandyk, and Mr. Walters. To develop my updated cost of equity analyses, I relied on the same methodologies used in my direct testimony except for one modification. In my direct testimony, I relied on projected earnings per share ("EPS") growth rates provided by *Yahoo! Finance* as one of the estimates of long-term growth in my constant growth DCF model; however, *Yahoo! Finance* no longer reports consensus projected three to five-year EPS growth rates. As a result, in my rebuttal testimony, I am now instead relying on the consensus projected three to five-year EPS growth rates reported by *S&P Capital IQ Pro* in my constant growth DCF model.

**Q. What are the updated results of your cost of equity analyses?**

A. Figure 2 summarizes the results of my updated analyses, which are also presented in Exhibit A-127 (AEB-2), pages 1 through 42.

**Figure 2: Cost of Equity Model Results**

***Constant Growth DCF***

| | Minimum Growth Rate | Average Growth Rate | Maximum Growth Rate |
|---|---|---|---|
| Mean Results: | | | |
| 30-Day Avg. Stock Price | 9.99% | 10.86% | 11.68% |
| 90-Day Avg. Stock Price | 10.09% | 10.97% | 11.78% |
| 180-Day Avg. Stock Price | 10.17% | 11.05% | 11.86% |
| Average | 10.08% | 10.96% | 11.77% |
| Median Results: | | | |
| 30-Day Avg. Stock Price | 9.78% | 10.91% | 12.14% |
| 90-Day Avg. Stock Price | 9.92% | 11.06% | 12.28% |
| 180-Day Avg. Stock Price | 10.10% | 11.24% | 12.47% |
| Average | 9.93% | 11.07% | 12.30% |

***CAPM / ECAPM / Bond Yield Risk Premium***

| | 30-Year Treasury Bond Yield | | |
|---|---|---|---|
| | Current 30-Day Avg | Near-Term Projected | Longer-Term Projected |
| CAPM: | | | |
| Current *Value Line* Beta | 11.25% | 11.23% | 11.22% |
| Current Bloomberg Beta | 10.11% | 10.05% | 10.02% |
| Long-term Avg. *Value Line* Beta | 10.23% | 10.18% | 10.14% |
| ECAPM: | | | |
| Current *Value Line* Beta | 11.42% | 11.40% | 11.39% |
| Current Bloomberg Beta | 10.56% | 10.52% | 10.49% |
| Long-term Avg. *Value Line* Beta | 10.65% | 10.61% | 10.59% |
| Bond Yield Risk Premium | 10.55% | 10.41% | 10.33% |

**Q. Do the updated results support the Company's requested ROE of 10.25% in this proceeding?**

A. Yes. The results of each of the DCF analyses have increased since the filing of my direct testimony, while the results of my CAPM and ECAPM analyses are generally consistent

with those filed in my direct testimony (i.e. the results of some scenarios have slightly increased while others have slightly decreased). The results of the Bond Yield Risk Premium have generally increased modestly since the filing of my direct testimony. Therefore, as shown, the results of the cost of equity analyses continue to support my direct testimony and exhibits and the Company's proposed ROE of 10.25% in this proceeding.

## IV. CAPITAL MARKET CONDITIONS AND A COMPARABLE RETURN

**Q. Do any parties analyze capital market conditions and its impact on the Company's ROE?**

A. Only Mr. Walters addresses capital market conditions in the context of setting an ROE,[6] while Mr. Coppola discusses interest rates in the context of mortgages, housing starts, and service connections.[7] Mr. Megginson and Mr. Bandyk do not discuss capital markets in any context.

**Q. What do Mr. Walters and Mr. Coppola say about capital market conditions?**

A. Mr. Walters believes that "economic activity is expanding solidly, with solid labor market conditions though inflation remains somewhat elevated," and cites a Federal Reserve Board statement from March 19, 2025 in support of this view.[8] Mr. Walters observes that there have been more credit downgrades than upgrades to utilities due to higher capital expenditures, wildfire risk, and uneven regulatory outcomes,[9] and he further observes that utility stocks have outperformed the broader market since the second half of 2021 due to a

[6] Walters Direct, at 11-21.
[7] Coppola Direct, at 20.
[8] Walters Direct, at 13.
[9] *Id*., at 17.

macro environment with "elevated inflation, rising interest rates, and uncertainty because of geopolitical events around the world."[10]

Mr. Coppola acknowledges that "persistently high inflation rates and other economic factors have prevented the Federal Reserve Bank from lowering interest rates with no clear expectation currently of further declines in 2025."[11] To account for "uncertainty of the timing in the decline in interest rates," Mr. Coppola arbitrarily adds 23 basis points to his cost of capital results of 9.52% to reach his recommended 9.75%.[12]

**Q. Do changes in capital market conditions since the Company's last rate proceeding continue to indicate an increase in the cost of equity?**

A. Yes. Changes in long-term bond yields since the Company's last rate proceeding, as well as since the filing of the Company's direct testimony in this proceeding, demonstrate an increase in the cost of capital. Specifically, as shown in Figure 3, although the federal funds rate has declined since the filing of the Company's direct testimony in this proceeding, long-term interest rates have increased 20 basis points over this period, which is indicative of an increase in the cost of equity. Core inflation has declined since the last rate proceeding and the filing of the direct testimony; although, it remains above the Federal Reserve's long-term target of 2.00%. The VIX, which is a measure of volatility, has increased significantly since both the Company's previous rate case and the Company's direct testimony in this proceeding, indicating heightened uncertainty in capital markets.

[10] *Id*., at 20-21.
[11] Coppola Direct, at 20.
[12] *Id*., at 153.

**Figure 3: Change in Market Conditions Since Consumers Energy's Last Rate Proceeding[13]**

| Docket | Date | Federal Funds Rate | 30-Day Avg 30 Year Treasury Bond Yield | Core Inflation Rate | 30-Day Avg VIX Index |
|---|---|---|---|---|---|
| Previous Case: U-21490 | 7/23/2024 | 5.33% | 4.44% | 3.23% | 13.04 |
| Current Case: U-21806 | | | | | |
| Direct | 12/16/2024 | 4.58% | 4.50% | 3.21% | 14.77 |
| Rebuttal | 4/30/2025 | 4.33% | 4.70% | 2.81% | 28.20 |
| *Increase / (Decrease):* | | | | | |
| Previous Case to Direct | | -0.75% | 0.05% | -0.01% | 1.74 |
| Previous Case to Rebuttal | | -1.00% | 0.26% | -0.42% | 15.16 |

**Q. Do you agree with Mr. Coppola's assessment of his recommended ROE in the context of current and projected interest rates?**

A. Although I appreciate that Mr. Coppola attempts to consider the uncertainty in the direction of interest rate policy, his recommended ROE, which includes an arbitrary adjustment to his model results of 23 basis points is inadequate.[14] Current market conditions demonstrate that there is no basis for a reduction in the Company's currently authorized ROE of 9.90%, and further demonstrate that there has been an increase in interest rates and uncertainty that suggests that the investor-required return has increased since the Company's last rate proceeding.

**Q. Do you agree with Mr. Walters's assessment of capital market conditions and its impact on the ROE?**

A. No. While I agree with Mr. Walters's summary of macroeconomic conditions, I disagree with his contention that utilities have been performing well since the second half of 2021.[15]

[13] St. Louis Federal Reserve Bank; Bureau of Labor Statistics; Bloomberg Professional.

[14] Coppola Direct, at 153.

[15] Walters Direct, at 20-22.

In addition, Mr. Walters fails to sufficiently discuss the heightened uncertainty in the economy that has an impact on capital investments.

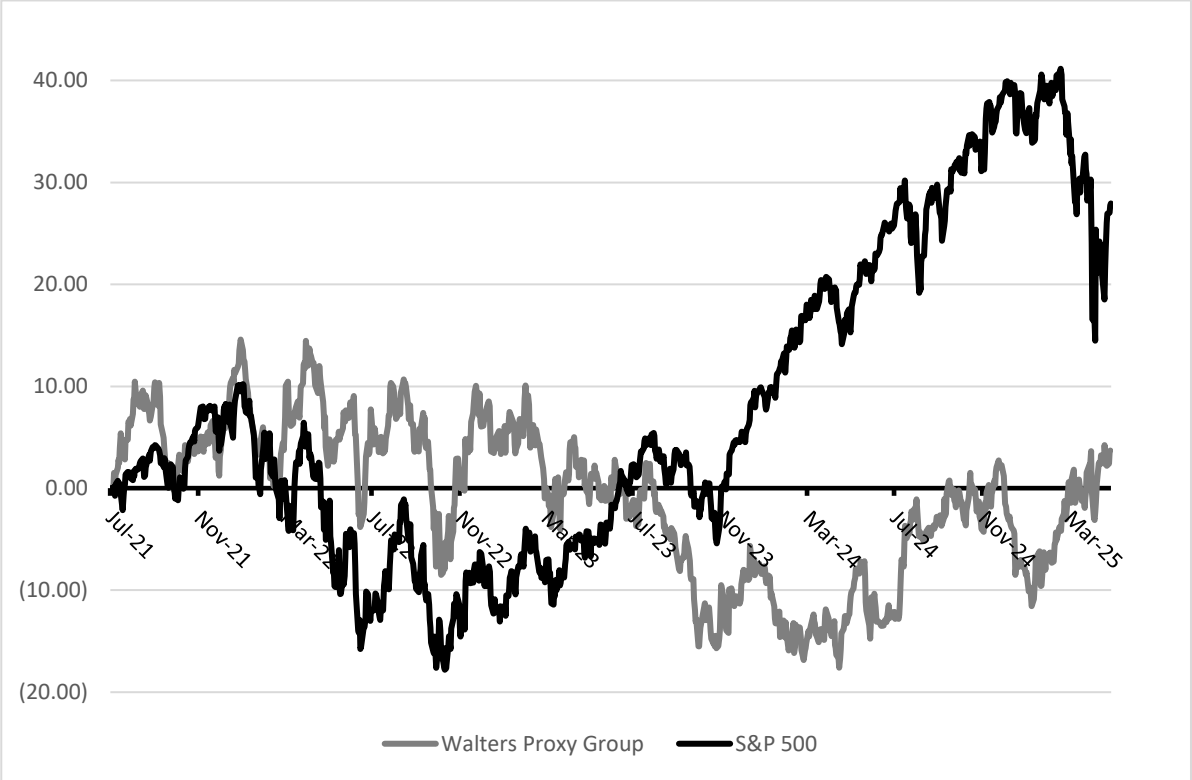
First, Mr. Walters's Figure CCW-4 provides misleading conclusions that the natural gas utility sector has outperformed the broader market in the recent period characterized by "elevated inflation, rising interest rates, and uncertainty because of geopolitical events around the world."[16] Specifically:

- Mr. Walters chooses to begin his analysis in the second half of 2021.
- Mr. Walters's S&P 500 Gas Utilities Sub Ind Index is misleading because there are only two gas utilities in the S&P 500, Atmos and NiSource, which is not representative of the entire natural gas industry.
- Mr. Walters does not show how water companies performed during this time, which is important considering he includes water companies in his proxy group, implying that he believes they have comparable risk profiles to natural gas utilities.

Figure 4 below shows the returns of the S&P 500 and Mr. Walters' proxy group since the second half of 2021, the same starting time-period Mr. Walters selects in his Figure CCW-4.[17] Because Mr. Walters views his proxy group as comparable to Consumers Energy, an index consisting of his proxy group companies is the appropriate benchmark to compare to the overall market. As shown in Figure 4, the S&P 500 significantly outperforms his proxy group; therefore, his conclusion that utilities have had "positive and relatively stable returns" is misleading.[18]

[16] *Id.*, at 21.
[17] Capital IQ Market Charts created a market capitalization weighted index.
[18] *Id*.

**Figure 4: Mr. Walters' Weighted Proxy Group Return and S&P 500 Index Price Index July 2021 through April 2025[19]**




In addition, despite mentioning it in passing, Mr. Walters does not sufficiently discuss uncertainty in macro conditions and its impact on capital markets and the cost of equity. He does not present any data on elevated volatility or market uncertainty. A recent article from *The Wall Street Journal* reports that companies are delaying investments and projects due to heightened uncertainty driven by the recent Trump tariffs.[20] Increased uncertainty means increased risk, which, all else equal, increases the cost of equity.

[19] *S&P Capital IQ*. Proxy group return is market capitalization weighted.

[20] Chip Cutter, "America Inc. Slashes Spending as Tariff Uncertainty Swirls," *The Wall Street Journal*, April 27, 2025.

**Q. What are the expectations for inflation and monetary policy over the near-term?**

A. At the March 2025 Federal Open Market Committee ("FOMC") meeting, Chairman Powell noted that labor market conditions are "solid" and while inflation has declined it remains above the Federal Reserve's target of 2.00%, as a result, the FOMC decided to maintain the current federal fund rate range of 4.25% to 4.50%.[21]

Regarding the possible path of monetary policy, Chairman Powell continued to reiterate that policy is "not on any preset course"; but he acknowledged increased uncertainly due to the implementation of significant policy changes (i.e. trade, immigration, fiscal policy, and regulation) by the Trump administration.[22] Mr. Walters' citation from the Federal Reserve notes that "[u]ncertainty around the economic outlook has increased."[23] Chairman Powell noted that the FOMC will continue to analyze incoming data to determine the effect of such policy changes and was in a good position to adjust the course of monetary policy if needed.[24] Thus, the FOMC's forecast of the federal funds rate remained unchanged from the December 2024 meeting, forecasting just two rate cuts before the end of 2025.[25]

More recently, during an event at the Economic Club in Chicago, Chairman Powell acknowledged that the recent tariff policy of the Trump Administration has caused volatility and uncertainty in the market, but that policy was currently well positioned and that the Federal Reserve could rely on incoming economic data to gain greater clarity on

[21] Transcript of Chair Powell's Press Conference, March 19, 2025.
[22] *Id.*
[23] Walters Direct, at 13.
[24] *Id.*
[25] Federal Reserve, Summary of Economic Projections, March 19, 2025, at 2.

the economic effects of the tariffs before considering changes to policy.[26] Further, in regard to economic conditions, Chairman Powell reiterated that the labor market was "in solid condition" but he did acknowledge that tariffs would cause temporary inflation that could be more persistent depending on how long it takes the tariffs to fully flow through to prices which the Federal Reserve is monitoring.[27]

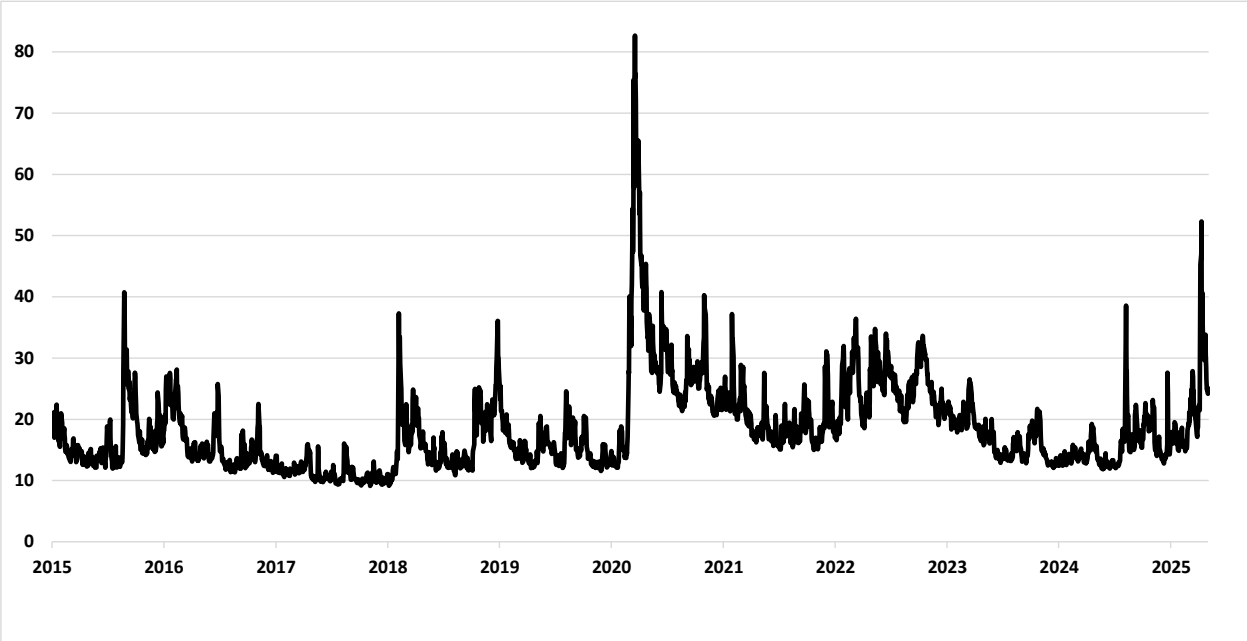
**Q. Has the recent tariff policy of the Trump Administration resulted in increased volatility in financial markets?**

A. Yes, financial markets have been extremely volatile since President Trump announced a significant set of tariffs on April 2, 2025. For example, as shown in Figure 5, the VIX, which measures investors' expectation of volatility in the S&P 500 over the next 30 days, has remained elevated since April 2, 2025, and peaked at 52.33 on April 8, 2025. The VIX has not reached 50.00 since April 2020 during the height of the COVID-19 pandemic. The high level of uncertainty associated with the economic effects of the Trump Administration's tariff policy has resulted in significant volatility increasing the risk of holding equity investments and implying an increase in the cost of equity.

[26] Howard Schneider and Ann Saphir, "Powell says Fed remains in wait-and-see mode; markets processing policy shifts," *Reuters*, April 16, 2025.

[27] *Id*.

**Figure 5: CBOE VIX, January 2015 – April 2025[28]**




**Q. Have you reviewed any other indicators that show that the Trump Administration's tariff policy has resulted in increased uncertainty?**

A. Yes. In addition to the recent high volatility as measured by the VIX, the University of Michigan's consumer sentiment index indicates consumer sentiment is at its second lowest point since 1952 and that inflation expectations are at the highest levels in 44 years.[29] Furthermore, a recent Bank of America Global Fund Manager Survey conducted in April 2025, shows investor sentiment at its 5th lowest point since the study began in 2001.[30]

[28] Bloomberg Professional Services.

[29] Harriet Torry, "'From anxious to petrified': Consumer sentiment plunges further," *Wall Street Journal*, April 11, 2025.

[30] Michael Hartnett, *et al*., "Global Fund Manager Survey: The Bear Necessities," *BoA Global Research*, April 15, 2025.

**Q. What are investors' expectations for the yields on long-term government bonds given the sustained elevated levels of inflation and the Federal Reserve's restrictive monetary policy?**

A. Economists and analysts are expecting elevated rates. *Blue Chip Financial Forecasts* provides a forecast from economists on the 30-year Treasury bond. In the most recently published *Blue Chip Financial Forecasts* report, economists projected the 30-year Treasury bond yield to remain relatively stable and decrease only slightly from 4.60% in Q2/2025 to 4.40% in Q2/2026.[31] Additionally, the most consensus estimate over the longer-term (i.e. 2026-2030) is 4.30%.[32] This is important because it means that long-term interest rates are expected to remain elevated during the period that the Company's rates will be in effect.

**Q. What are your conclusions regarding current market conditions?**

A. Although the federal funds rate and core inflation have decreased since the Company's last rate proceeding, the 30-year Treasury bond yield remains elevated and the VIX has significantly increased as a result of tariffs and the uncertainty related to the current administration's policies. Chairman Powell has indicated that the Federal Reserve is in wait-and-see mode and will rely on incoming data to determine when it is appropriate to adjust the federal funds rate. Furthermore, there are economic indicators that suggest both consumer and investor sentiment is weakening. With elevated expected interest rates, borrowing is more expensive, which in turn raises the cost of capital. As a result, investors demand higher returns on equity, leading to an increase in the cost of equity.

[31] *Blue Chip Financial Forecasts*, Vol. 44, No. 5, May 1, 2025, at 2.
[32] *Blue Chip Financial Forecasts*, Vol. 43, No. 12, November 27, 2024, at 14.

**Q. What is Mr. Megginson's view on recently authorized ROEs?**

A. Mr. Megginson provides the average authorized ROE for 2022, 2023, and 2024, which recognizes that the authorized ROEs have been increasing, from 9.53% to 9.72%. Mr. Megginson suggests that the three-year average is 9.63%, which he concludes is "well below" Staff's ROE recommendation of 9.75%.[33]

**Q. Do you agree with Mr. Megginson's analysis of authorized ROEs?**

A. No. As discussed in more detail in the remainder of my testimony, the relationship between the cost of equity and interest rates is important to consider. In averaging data for the three-year period from 2022 through 2024, Mr. Megginson fails to consider the interest rate environment over this time-period. As shown in Figure 4 of my direct testimony, in 2022, the yield on the 10-year Treasury bond was significantly lower than in current market conditions, beginning at 1.50% and increasing over the year, reaching approximately 4.25% by year end. Given the lag associated with the regulatory process, it is reasonable to expect that many of the ROEs that were authorized in 2022 were based on 2021 data or data as of the beginning of 2022; a time-period that does not reflect the current interest rate environment. Including data from 2022 in the average return that he uses to benchmark his proposed ROE in the current interest rate environment, is not an appropriate comparison.

[33] Megginson Direct, at 35.

**Q. Have you reviewed more current authorized ROEs data than Mr. Megginson presented?**

A. Yes. I reviewed the range of authorized ROEs in 2024 and the averages. While I agree with Mr. Megginson that the average authorized ROE in 2024 for natural gas utilities was 9.71%, the high end of the range was 11.88%.

**Q. What is Mr. Bandyk's position regarding previously authorized ROEs?**

A. Mr. Bandyk claims that the Commission, as well as all other regulatory commissions across the United States, have incorrectly authorized ROEs for decades. Mr. Bandyk cites three sources to support his claim. Specifically, Mr. Bandyk contends that regulated utilities have "been awarded ROEs above market return," and that "regulatory commissions have tended to accept estimates for ROE that are above fair, market-based ROE estimates."[34] Based on this assumption, Mr. Bandyk suggests that previously authorized ROEs should not be considered for purposes of establishing the ROE for the Company in this proceeding. Furthermore, Mr. Bandyk claims that the Commission's goal is to help maintain a utility's "financial integrity":

> But a return sufficient to maintain "financial integrity" only implies that the utility be able to attract capital – not that it can attract capital on the terms that it currently does. A utility can still attract capital with a lower ROE. For example, if a lower ROE causes the stock price to drop, that lower price will attract new investors.[35]

[34] Bandyk Direct, at 7.
[35] *Id*., at 8.

**Q. Is Mr. Bandyk's position consistent with Mr. Megginson's, Mr. Coppola's, or Mr. Walters' testimony?**

A. No, Mr. Bandyk is alone in his position. Mr. Megginson specifically considers previously authorized ROEs for natural gas utilities in developing his recommended ROE in this proceeding, Mr. Coppola also references previously authorized ROEs as support for his recommended ROE, and Mr. Walters analyzes trends in authorized ROEs when reviewing capital markets and his Risk Premium analysis. [36]

**Q. Based on his position that regulators have consistently incorrectly authorized ROEs in the past, what is Mr. Bandyk's ROE recommendation for the Company?**

A. Mr. Bandyk states that the average of his cost of equity model results suggests a market-based cost of equity for Consumers Energy that is lower than his recommended ROE of 9.24%. However, Mr. Bandyk acknowledges that there is uncertainty in any financial model and there is a need "not to create unnecessary instability in the company's market value, which is based to a great degree on the outcomes of regulatory proceedings like this one."[37] Therefore, Mr. Bandyk states that his ROE recommendation represents "gradualism" in moving from the Company's currently authorized ROE to his recommended ROE, despite his claim that his recommendation is higher than the market-based cost of equity for Consumers Energy.[38]

[36] Megginson Direct, at 35-36; Coppola Direct, at 146-147; Walters Direct, at 4-5, and 44.
[37] Bandyk Direct, at 12.
[38] *Id*.

**Q. Does Mr. Bandyk indicate the point or range to which he believes the Company's ROE should transition to over time?**

A. No. Mr. Bandyk has not defined where he believes the ultimate end point is of his proposed "gradualism."

**Q. Do you agree with Mr. Bandyk's position?**

A. No. Mr. Bandyk and I have a fundamental disagreement regarding his claim that regulators have incorrectly authorized ROEs substantially higher than the cost of equity for decades. I agree with him that: (1) there is a distinction between the cost of equity and the ROE authorized by regulatory commissions in setting just and reasonable rates; (2) the cost of equity cannot be definitively determined and therefore must be estimated by analysts; and (3) there is significant disagreement as to the way in which to estimate the cost of equity. However, he has provided no evidence that supports his position that regulatory commissions, including this Commission, have consistently erred for decades in establishing utilities' ROEs.

**Q. Why is this disagreement with Mr. Bandyk so fundamental?**

A. Regulatory commissions have an obligation to establish rates that balance the interests of customers and shareholders and that are just and reasonable. There is no evidence that Mr. Bandyk's estimate of the cost of equity, which includes the results of his CAPM analysis that is substantially lower than any ROE that has been authorized by a regulatory commission in the past, is in fact reasonable and that regulatory commissions have been consistently approving unjust and unreasonable rates.

**Q. As a threshold matter, are you aware of any other regulatory jurisdiction in the United States that has adopted Mr. Bandyk's views?**

A. No. I am not aware of any regulatory commission in the United States – state or Federal – that has adopted Mr. Bandyk's position.

**Q. Are you aware of any regulatory commissions that have specifically disagreed with Mr. Bandyk's notion that there is and has been a substantial difference between authorized ROEs and the cost of equity for utilities?**

A. Yes. For example, when the same argument was made by the Minnesota Department of Commerce, Division of Energy Resources, the Minnesota Public Utilities Commission clearly stated in a recent decision that it did not agree that utility ROEs have exceeded the cost of equity historically:

> The Department's recommended cost of equity of 9.30% is informed by an underlying assumption that the cost of equity and the return on equity are distinct concepts in the sense that utility earnings exceed the cost of equity over time. This understanding, according to the Department, undermines the reliability of earnings' estimates in predicting long-term growth and instead justifies the use of a multi-stage DCF analysis that uses GDP to forecast the long-term cost of equity. ***The Commission does not share this concern***.[39]

**Q. Are you aware of examples where capital attraction and willingness to invest have been hampered when a regulatory jurisdiction is perceived as not being credit supportive?**

A. Yes. Connecticut and Illinois are two recent examples. In Illinois, market reactions to regulatory decisions in December 2023 for Ameren Illinois Co. and Commonwealth

[39] Minnesota Public Utilities Commission, Docket No. E-015/GR-21-335, Findings of Fact, Conclusions, and Order, February 28, 2023, at 45; emphasis added.

Edison Co. were universally negative and both utilities considered shifting investment to their other utility operating subsidiaries outside of Illinois.

Connecticut, which is viewed by research analysts, equity analysts, and investors as among the least credit supportive jurisdictions in the United States for utilities, is the most recent example of where capital attraction and a willingness to invest have been hampered. For example:

- The two major utility holding companies operating in Connecticut (i.e. Eversource Energy ("Eversource") and Avangrid Inc. ("Avangrid")) have announced their unwillingness to continue discretionary investment in the state until the regulatory environment and cost recovery outcomes change.
- Avangrid's utility operating subsidiaries in Connecticut (i.e. Connecticut Natural Gas Corporation ("CNG") and Southern Connecticut Gas Company ("SCG")) have recently experienced difficulty fully subscribing bond issuances, and while able to do so, the premiums were higher than anticipated.

Specifically, in May 2024, Eversource, which owns Connecticut Light & Power and Aquarion Water in Connecticut, announced on its earnings call that it would be cutting investment by its utilities within the state due to "unreasonable, arbitrary decisions by the regulator," (i.e. the Public Utilities Regulatory Authority ("PURA")), and that the company had "grave concerns" regarding the Connecticut regulatory environment.[40] Eversource executives stated that the company is unwilling to place capital at risk within Connecticut given that the state's regulatory policy discourages investment.[41] Driving the cut in utility investment is Eversource's view that utility regulators have been slow to approve the recovery of $635 million in storm costs incurred from 2018 through 2021, $400 million in

[40] Mark Pazniokas, "Eversource escalates CT fight, saying it will cut investments," CT Mirror, May 2, 2024.

[41] Jared Anderson, "Eversource cutting investment in Connecticut by up to $500 million over 5 years," S&P Capital IQ Pro, May 3, 2024.

uncollected bills from ratepayers, a rate reduction imposed on Aquarion Water in its most recent rate proceeding, and elimination of a program supporting electric vehicles.[42] Consequently, Eversource stated that it is taking a "hard look" at its capital deployment priorities in Connecticut and plans to reduce its capital investment in Connecticut by $500 million over the next five years, which will likely come from reliability areas until "Connecticut's regulatory decisions come back into alignment with law and state policy."[43] Eversource indicated that it will not reduce safety spending, but that it has made significant investments in reliability over the past decade but is unwilling to continue doing so without a secure and predictable cost recovery path.[44] Moreover, since that time, Eversource has entered into an agreement to sell Aquarion Water.[45]

Similarly, Avangrid, which owns United Illuminating, CNG, and SCG in Connecticut, has also announced that its planned $191 million in capital investment in the state hinges on the regulatory decisions associated with the pending rate cases of CNG and SCG, and the resolution of Avangrid's ongoing legal appeal of PURA's August 2023 order whereby United Illuminating's rate request was reduced from $131 million to $23 million, which the utility says will require it to operate at a loss.

In addition, Avangrid has indicated that it experienced difficulties in attracting adequate subscription levels for debt issuances by its Connecticut utilities that closed in

[42] Mark Pazniokas, "Eversource escalates CT fight, saying it will cut investments," CT Mirror, May 2, 2024.

[43] Jared Anderson, "Eversource cutting investment in Connecticut by up to $500 million over 5 years," S&P Capital IQ Pro, May 3, 2024.

[44] *Id*.

[45] "Eversource Energy Announces Sale of Aquarion Water Company," Business Wire, January 27, 2025.

December 2023, and the bonds priced at a higher coupon rate than anticipated.[46] Specifically, as stated in its currently pending rate proceeding:

> The debt issuance was a private offering in which four banks served as lead placement agents and worked with the Company to market the transaction to investors in advance of pricing. On the day of pricing, November 15th, the subscriptions sought for CNG and SCG were only 65% and 50% fulfilled, respectively. This compares to the offering for one of the other Avangrid utilities which was more than two-times subscribed. After some additional negotiation, the banks were able to get one investor to fill the remaining portions of the issuance sought for CNG and SCG and the full transaction priced on the following day; however, the credit spreads were wider than anticipated across the Avangrid Connecticut utilities, raising the financing cost by approximately 10-15 basis points. *The bankers informed Avangrid that the difficulty in fulfilling the necessary subscription levels and the wider credit spreads attracted were caused in part by the limited interest to invest in Connecticut utilities due to concerns over the regulatory environment and potential impacts to current ratings*.[47]

**Q. Have utilities shifted investment outside of a jurisdiction that is viewed as unsupportive?**

A. Yes. After Eversource's announcement to curtail investment in Connecticut, Guggenheim Partners analyst Shahriar Pourreza noted that the threats to reduce investment should be taken seriously and that it has happened in other states, most recently in Illinois. Because utilities are capital intensive and inherently cash-flow negative, Mr. Pourreza stated that he has seen utilities that operate in multiple jurisdictions shift capital to where the return is more predictable.[48]

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[46] Public Utilities Regulatory Authority, Docket No. 23-11-02, Response of Connecticut Natural Gas Corporation to data request RRU-402, February 27, 2024.

[47] *Id*., emphasis added.

[48] Mark Pazniokas, "Eversource escalates CT fight, saying it will cut investments," CT Mirror, May 2, 2024.

**Q. What three sources does Mr. Bandyk cite to claim that awarded ROEs are too high and why are they not credible sources to support his conclusions?**

A. The three sources that Mr. Bandyk cites are: (1) a paper published by Rode and Fischbeck (2019) on the growing market risk premium; (2) an Energy Institute *working paper* that Mr. Bandyk claims is published to presumably lend it more credibility; and (3) an op-ed article from *Fortnightly Magazine* from 2016 by a lawyer.[49] None of these sources credibly support Mr. Bandyk's claim that "public regulatory commissions on average have tended to set electric utility ROEs above what economists would arrive at using the widely-accepted methods for estimating ROE."[50]

Rode and Fischbeck (2019) is the only peer-reviewed published academic article, and it studies the spread between *electric* ROEs and risk-free rates. As a threshold matter, this paper does not look at *natural gas* ROEs. The paper does not use causal empirical techniques to support a conclusion that ROEs are too high. The paper only considers the CAPM model, and it does not evaluate the DCF and other considerations that may impact ROEs such as capital market conditions. Most strikingly, the authors conclude that "[o]ur research does not necessarily imply that the rates of return authorized by regulators are too high, or otherwise necessarily inappropriate for utilities."[51] Therefore the paper does not support Mr. Bandyk's conclusion that a "market-based ROE" should be lower than recently authorized ROEs.

[49] Bandyk Direct, at 5-6.
[50] *Id*., at 5.
[51] David Rode and Paul Fischbeck, "Regulated equity returns: A puzzle," *Energy Policy*, October 2019.

The working paper by Werner and Jarvis suffers from several limitations. First, the study, which benchmarks authorized returns to corporate bond yields and Treasury bond yields, incorrectly assumes that a 1.00 percentage point change in the yield on Treasury bonds will result in a 1.00 percentage point change in the authorized returns. However, the authors provide no references to studies or other information to support their assumption. Further, when the authors calculated an alternative scenario that assumed the authorized return would change at only half the rate of change in the Treasury yield (i.e. a 100 basis point increase in the Treasury yield would result in a 50 basis point increase in the authorized ROE), the spread between the estimated benchmark returns and the authorized returns decreased significantly and did not show an increasing trend over the study period, which suggests that their initial 1-to-1 relationship between the change in the yield on Treasury bonds and the change in authorized ROEs is flawed.[52]

Second, the authors acknowledged that their analysis, which compares authorized returns to the cost of equity estimates resulting from the CAPM, is highly dependent on the assumptions used to calculate the CAPM. Further, their analyses demonstrated the sensitivity of their results to the assumptions relied on in the CAPM. The authors used two CAPM analyses, with significantly different assumptions and demonstrated that the spread between the cost of equity results of these models and authorized returns were dramatically different. For example, the first CAPM analysis resulted in a spread between the estimated cost of equity and the authorized return of 3.89 percentage points in 2022, while the second

[52] Karl Dunkle Werner and Stephen Jarvis, "Rate of Return Regulation Revisited," Working Paper, Energy Institute, University of California at Berkeley, 2024, at 20.

CAPM analysis produced a spread of only 1.19 percentage points.[53] Therefore, this test demonstrated that their analysis was highly dependent on the assumptions used in the CAPM and did not support a conclusion that authorized ROEs were systematically higher than the cost of equity:

> Bolstering the financial expertise of regulators is another promising path forward. Seemingly objective methods like the capital asset pricing model cannot provide a definitive answer on the cost of equity. As we have documented, a range of plausible input assumptions can lead to widely divergent estimates of the cost of equity. When incorporating evidence from these methods regulators need to have the expertise to understand their limitations and push back on the assumptions utilities put forward when using them.[54]

Finally, the authors acknowledge that "there are many differences between the utility sector and investor environment in the US and UK," and these differences in the risk factors between utility operations in the United States and the United Kingdom ought to be addressed but are not addressed in their work.[55] Given that the authors acknowledge there are differences in the regulatory environments, yet have not considered the effect of those differences on the cost of equity for the electric and natural gas utilities in either the UK or US, it is not reasonable to conclude that the authorized ROEs in the US are too high based on a comparison to the returns authorized for utilities in the UK. As a result, the limitations of the Werner and Jarvis (2024) study do not support Mr. Bandyk's contention that US state regulatory commissions have consistently authorized ROEs in excess of the cost of equity.

[53] *Id.*, at Appendix B.2 page 12.
[54] *Id.*, at 39.
[55] *Id.*, at 21.

The third source cited by Mr. Bandyk is an op-ed from *Public Utilities Fortnightly* from 2016 by Steve Huntoon, a utility attorney who claims that commissions set authorized ROEs at rates that are higher and not consistent to utilities' risk level.[56] As a threshold matter, although Mr. Huntoon has a background in energy, he is not a cost of capital expert, and this article is merely his opinion. Mr. Huntoon recommends individuals invest in Vanguard's utility ETF, VPU, because there have been periods where regulated utilities have outperformed the broader market. However, since the article's publication in August 2016, the VPU has significantly lagged the S&P 500 Index through April 30, 2025, with the VPU returning approximately 94% over this period, while the S&P 500 has returned approximately 199%.[57] Clearly, this refutes Mr. Bandyk's claims that utilities violate "the economic reality that lower risk means lower return."[58]

**Q. Does Mr. Bandyk define "financial integrity" or at what point a utility will struggle to attract capital with a low ROE?**

A. No. Mr. Bandyk believes that a utility can attract capital and new investors under any circumstances, regardless of a low ROE leading to a stock price decline.[59] This ignores the opportunity cost principle in finance. As discussed in my direct testimony, utilities compete for capital with other investments of similar risk.[60] If both ROE and stock price decrease, investors' required returns would increase as the perceived Company's risk increases. Mr. Bandyk does not suggest at what low ROE level it becomes infeasible to

[56] Steve Huntoon, "Nice Work If You Can Get It," *Fortnightly*, August 2016; Mr. Bandyk did not provide the article as the article is behind a paywall, and only two pages of the article is accessible.
[57] *S&P Capital IQ* from August 1, 2016 – April 30, 2025.
[58] Bandyk Direct, at 6.
[59] Bandyk Direct, at 8.
[60] *Id*., at 7.

attract capital, nor does he describe the difficulty Consumers Energy would face to fund its operations with a lower ROE and lower stock price.

In conclusion, I strongly disagree with Mr. Bandyk's suggestion that authorized ROEs have been set too high by regulatory commissions across the United States, including this Commission, and that ROEs of any level can attract adequate capital even with resulting lower stock price.

## V. PROXY GROUP

**Q. How have Mr. Megginson, Mr. Coppola, Mr. Walters, and Mr. Bandyk specified their respective proxy groups?**

A. To estimate the cost of equity for Consumers Energy, Mr. Megginson, Mr. Coppola, Mr. Walters, and Mr. Bandyk develop their respective proxy groups as follows:

- Mr. Megginson utilizes a proxy group of eight companies, six of which overlap with my proxy group. Relative to my proxy group, Mr. Megginson includes two additional companies: New Jersey Resources ("NJR") and DTE Energy ("DTE"). While DTE did not meet the screening criteria applied by Mr. Megginson, he includes DTE because it is the "primary comparison utility" to Consumers Energy in Michigan.[61]

- Mr. Coppola relies on a proxy group of eight companies, six of which are the companies in my proxy group. The two additional companies in Mr. Coppola's proxy group are: Black Hills Corp. ("BKH") and Chesapeake Utilities ("Chesapeake").[62]

- Mr. Walters starts with the same proxy group that I have utilized, but excludes NiSource since, in early 2024, the company completed the sale of a 20% ownership interest in Northern Indiana Public Service Company ("NIPSCO"). In addition, Mr. Walters states that since there are only five companies remaining in the proxy group once he excludes NiSource, he includes six

[61] Megginson Direct, at 20.
[62] Coppola Direct, at 131.

additional water utilities in his proxy group in order to expand the proxy group.[63]

- Mr. Bandyk relies on the same proxy group for his cost of equity analyses as I have utilized.

**Q. Do you have any concerns with the screening criteria relied upon by Mr. Megginson?**

A. Yes, I disagree with Mr. Megginson's screen that ensures the companies included in the proxy group derive a certain portion of their operations from regulated natural gas distribution operations for two reasons. First, Mr. Megginson's screen relies on revenue instead of operating income. However, operating income is the more appropriate screening criterion because it better reflects the contribution of each business segment to the corporation's earnings. For regulated utilities that collect the cost of purchased gas, fuel, and/or power on a pass-through basis through rates, regulated revenue can fluctuate materially with changes in weather without affecting the corporation's earnings or financial position. In contrast, operating income, which excludes purchased commodity costs, more closely represents the effect of each business segment on the corporation's overall risk profile.

Second, Mr. Megginson requires that a company derive at least 50% of revenues from regulated natural gas distribution operations; however, the required percentage should be greater than 50% because Mr. Megginson's screen could result in a company being included in the proxy group that derives 50% of total revenue from unregulated operations. It is unreasonable to conclude that a company that derives 50% of total revenue from

[63] Walter Direct, at 30.

unregulated operations would be considered comparable to a company that derives 100% of revenue from regulated natural gas distribution operations such as Consumers Energy.

**Q. Would the composition of Mr. Megginson's proxy group change had he relied on an operating income screen as opposed to a revenue screen?**

A. Yes. If Mr. Megginson correctly relied on an operating income screen as opposed to a revenue screen, he would have excluded NJR from his proxy. As shown in Exhibit A-127 (AEB-2), page 25, NJR derived only 50.02% of its total operating income from regulated natural gas distribution operations for the three-year period of 2022-2024. While NJR would meet an operating income screen that, similar to Mr. Megginson's screen, required a company to have greater than 50% of total operating income derived from natural gas operations; as also shown in Exhibit A-127 (AEB-2), page 25, NJR derives only 56.48% of total operating income from regulated operations for the three-year period of 2022-2024. Therefore, NJR has significant unregulated operations and should have been excluded from Mr. Megginson's proxy group.

**Q. Do you agree with Mr. Megginson's inclusion of DTE in his proxy group?**

A. No. While I do not agree with the screening criteria developed by Mr. Megginson, he developed the criteria to select companies that would be viewed by investors as comparable to Consumers Energy's natural gas operations. However, as Mr. Megginson acknowledges, DTE did not meet his screening criteria. Furthermore, DTE is classified by *Value Line* as an electric utility because DTE provides electric service to approximately 2.3 million customers across Michigan and owns and operates approximately 12,000 MW

of electric generation.[64] As shown in Exhibit A-127 (AEB-2), page 25, DTE derived only 22.49% of total operating income from regulated natural gas operations for the three-year period of 2022-2024 whereas DTE derived 65.83% of total operating income from regulated electric operations. Given DTE's substantial electric operations, it is clear that DTE is not comparable to Consumers Energy's natural gas operations and should have been excluded from Mr. Megginson's proxy group. It is not reasonable to conclude as Mr. Megginson has that a company such as DTE should be included in the proxy group if the company operates in the same state as the subject company.

**Q. Do any of the other witnesses include either NJR or DTE in their respective proxy groups?**

A. No. Neither Mr. Coppola, Mr. Walters, nor Mr. Bandyk have included NJR or DTE in their respective proxy groups. Further, Mr. Coppola specifically notes that he excluded NJR because "it earns less than 50% of its income from the utility business".[65]

**Q. Have you identified any errors in Mr. Coppola's application of his "utility business" screen?**

A. Yes. Mr. Coppola appears to rely on a screen that requires a company to derive approximately 50% of its operations (as measured by either revenue, operating income or net income) from its utility business (i.e. regulated electric and natural gas operations) to be included in his proxy group.[66] However, Mr. Coppola incorrectly calculated the percentage of total operating income derived from regulated electric and natural gas

[64] DTE, 2024 Form 10-K, at 7-8.
[65] Coppola Direct, at 131.
[66] *Id*.

operations, which resulted in the erroneous inclusion of Chesapeake in Mr. Coppola's proxy group. Specifically, Mr. Coppola incorrectly classified the operating income associated with Chesapeake's natural gas transmission assets as operating income associated with its "utility business." Further, as shown in Exhibit AG-46, this classification is in direct conflict with his calculation for Atmos Energy where he excluded the pipeline business from its "utility business". As a result, as shown in Exhibit AG-46, Mr. Coppola incorrectly concluded that Chesapeake derived 86 percent of their total operating income from utility operations. However, as shown in Exhibit A-127 (AEB-2), page 25, excluding the operating income derived from natural gas transmission operations, Chesapeake derived only 44.03% of its total operating income from regulated electric and natural gas operations (i.e. "utility business") for the three-year period of 2022-2024. Further, excluding both the operating income from natural gas transmission operations and electric operations, Chesapeake only derived 39.52% of its total operating income from regulated natural gas operations, which, as shown in Exhibit A-127 (AEB-2), page 25, is less than NJR, a company that Mr. Coppola excluded from his proxy group. It is clear that Mr. Coppola should have excluded Chesapeake from his proxy group.

**Q. Do you agree with Mr. Coppola's decisions to include BKH in his proxy group?**

A. No. As Mr. Coppola acknowledges, BKH is classified by *Value Line* as an electric utility. Further, while I agree with Mr. Coppola that approximately 50% of the company's operating income is from natural gas utility operation, the reason that *Value Line* classifies BKH as an electric utility is that the company provides electric service to approximately 222,000 customers across four states and owns and operates approximately 1,400 MW of

electric generation.[67] The fact that the company has substantial vertically-integrated electric utility operations makes it not comparable to Consumers Energy's natural gas utility operations in Michigan.

**Q. Do any of the other witnesses include either Chesapeake or BKH in their respective proxy groups?**

A. No. Neither Mr. Megginson, Mr. Walters, nor Mr. Bandyk have included either Chesapeake or BKH in their respective proxy groups.

**Q. Do you have any concerns with Mr. Walters's proxy group?**

A. Yes. My primary concern with Mr. Walters's proxy group is that he excludes NiSource because he contends the company was engaged in a transformative transaction.

**Q. Do you agree that companies engaged in transformative transactions should be excluded from the proxy group?**

A. Yes. As noted in the proxy group screening criteria discussed in my direct testimony, I agree with Mr. Walters that significant merger and acquisition ("M&A") activity that materially affects a company's finances should be excluded from use in a proxy. The purpose of applying an M&A screen is to isolate companies that are involved in transformative transactions that cause a fundamental change in a company and its financials. The larger the size of the transaction, the greater the likelihood that the transaction will have a significant effect on the share prices of the firms involved. Thus, it is important to exclude the companies involved in transformative transactions from the proxy group so that the temporary effect of the transaction does not affect the inputs to the

[67] S&P Capital IQ Pro.

cost of equity analyses. However, excluding companies based on non-transformative transactions unnecessarily reduces the size of the proxy group and eliminates companies that investors would consider alternatives.

**Q. Was the NiSource transaction transformative?**

A. No. As Mr. Walters notes, NiSource announced the sale of a minority ownership interest in one of its subsidiary utilities (i.e. a 19.9% noncontrolling interest in NIPSCO) on June 20, 2023. However, this sale of a noncontrolling interest in NIPSCO did not affect the stock price of NiSource when the transaction was announced, and thus there is no reason to exclude it from the proxy group. Specifically, in the 10 trading days prior to the transaction announcement, NiSource's stock price traded between $25.76 and $26.36. Likewise, in the 10 trading days after the transaction announcement, NiSource's stock traded between $25.71 and $26.82 – or effectively the same range.[68] Thus, there is no evidence to suggest that NiSource's sale of a noncontrolling interest in NIPSCO was transformative, and thus, there is no basis to exclude NiSource from the proxy group.

**Q. Are there other reasons that this transaction should not be the reason that NiSource is excluded from a proxy group at this time?**

A. Yes. The transaction occurred in June 2023, which means that it is prior to the analytical period that was used by any of the witnesses in this proceeding. Since the transaction preceded the analytical period that is being used in this case, it cannot have an effect on the current market data, which is the reason that we eliminate transformative transactions. For

[68] Stock prices reflect the adjusted closing price for NiSource as reported by *Yahoo! Finance*.

this reason, it is unreasonable to exclude NiSource from the proxy group based on this transaction.

**Q. Have the other witnesses included NiSource in their respective proxy groups?**

A. Yes. Mr. Megginson, Mr. Coppola, and Mr. Bandyk have each included NiSource in their respective proxy groups.

**Q. What is your conclusion regarding the appropriate proxy group for Consumers Energy?**

A. I continue to support the use of the screening criteria outlined in my direct testimony to develop the proxy group for Consumers Energy.

## VI. DCF ANALYSIS

**Q. Please summarize the DCF analyses of these witnesses.**

A. Mr. Megginson, Mr. Coppola, Mr. Walters, and Mr. Bandyk have each conducted a form of the DCF analysis. Specifically:

- Mr. Megginson conducts a constant growth DCF, and for each of his proxy group companies relies on (1) an average of closing monthly stock prices as of January 1, February 1, and March 1, 2025; (2) annualized dividends that reflect one-half of the estimated growth rate; and (3) projected EPS growth rates from *Value Line* and *Zacks Investment Research* ("*Zacks*"). The average cost of equity resulting from Mr. Megginson's constant growth DCF analysis is 9.40%.[69]

- Mr. Coppola conducts a constant growth DCF, and for each of his proxy group companies relies on (1) an average of the 30-day high and low stock prices; (2) projected dividends as reported by *Value Line*; and (3) analysts' projected EPS growth rates as published by *Value Line* and *Zacks* as his growth rates.[70] Mr. Coppola does not rely on the projected EPS growth rates published by *Value Line*, but instead calculates projected EPS growth rates using the actual

[69] Megginson Direct, at 24.
[70] Coppola Direct, Exhibit AG-43.

EPS for 2024 and projected EPS for 2029 as published by *Value Line*. The average cost of equity from Mr. Coppola's constant growth DCF analysis is 9.11%.

- Mr. Walters conducts three DCF analyses: two constant growth DCF models (i.e. one version that relies on analysts' projected EPS growth rates and the other that relies on estimated sustainable growth rates), and a multi-stage DCF model. Mr. Walters' multi-stage DCF model relies on analysts' projected EPS growth rates in Stage 1 (years 1-5) and a growth rate of 4.14% in Stage 3 (year 11 onward) to represent projected long-term gross domestic product ("GDP") growth, while the growth rate in Stage 2 (years 6-10) transitions between the Stage 1 and Stage 3 growth rates.[71] The results of these analyses range from 8.38% to 13.54%.[72]

- Mr. Bandyk conducts a two-stage DCF analysis whereby he relies on: (1) an average of the 30-day high and low stock prices; (2) annualized dividends that I relied on in my direct testimony; (3) projected EPS growth rates that I relied on in my direct testimony; and (4) a projected nominal GDP growth rate of 3.80%. To calculate the growth rate, Mr. Bandyk applies a weighting of 80% to the average of the analysts' projected EPS growth rates and a weighting of 20% to his long-term growth rate of 3.80%.[73] The resulting cost of equity of Mr. Bandyk's constant growth DCF is 9.22%.

**Q. What is your primary area of disagreement with the constant growth DCF analyses conducted by Mr. Megginson?**

A. I have two primary concerns with Mr. Megginson's constant growth DCF model. First, as noted previously, I disagree with Mr. Megginson's inclusion of DTE and NJR in the proxy group. NJR has substantial unregulated operations and DTE has substantial vertically integrated electric utility operations; thus, neither company is comparable to Consumers Energy.

[71] Walters Direct, at 37-38.
[72] *Id.,* at 43.
[73] Bandyk Direct, at 23 and Exhibit CUB-18.

Second, while Mr. Megginson contends that he has relied on projected EPS growth rates from *Zacks* as of March 12, 2025, the projected EPS growth rates he relies on for each of the companies included in his proxy group do not appear to tie to the projected EPS growth rates reported by *Zacks*. For example, while I do not have access to the projected EPS report by *Zacks* on March 12, 2025, I did download from *Zacks* the projected EPS growth rates for each of the companies included in Mr. Megginson's proxy group as of February 28, 2025, and March 31, 2025. As shown in Figure 6 below, for seven of the eight companies included in Mr. Megginson's proxy group, the projected EPS growth rate from *Zacks* did not change from February 28, 2025 to March 31, 2025. However, of the seven companies that did not have a change in the projected EPS growth rate, Mr. Megginson reported a different growth rate for six out of the seven companies. Therefore, while the source of Mr. Megginson's projected EPS growth rates appears unclear, it is reasonable to conclude that they do not represent the projected EPS growth rates reported by *Zacks* on March 12, 2025.

**Figure 6: Projected EPS Growth Rates – Zacks**

| Company | Ticker | Megginson (March 12, 2025) | Zacks (Feb. 28, 2025) | Zacks (March 31, 2025) |
|---|---|---|---|---|
| Atmos Energy Corporation | ATO | 7.10% | 7.10% | 7.10% |
| DTE Energy Company | DTE | n/a | 7.60% | 7.60% |
| New Jersey Resources Corporation | NJR | 6.00% | n/a | n/a |
| NiSource Inc. | NI | 6.00% | 8.20% | 8.20% |
| Northwest Natural Gas Company | NWN | 3.70% | n/a | n/a |
| ONE Gas, Inc. | OGS | 3.98% | 4.70% | 4.70% |
| Southwest Gas Corporation | SWX | 5.00% | 6.60% | 6.60% |
| Spire, Inc. | SR | 5.62% | 5.80% | 6.50% |

**Q. Did you adjust Mr. Megginson's constant growth DCF analysis to reflect the issues you have identified?**

A. Yes. Specifically, I adjusted Mr. Megginson's constant growth DCF analysis to: (1) exclude NJR and DTE from his proxy group; (2) rely on projected EPS growth rates from *Zacks* as of March 31, 2025. As shown in Exhibit A-127 (AEB-2), page 27, applying these reasonable adjustments and corrections to Mr. Megginson's constant growth DCF increases his constant growth DCF result 95 basis points from 9.40% to 10.34%.

**Q. Did you also update Mr. Megginson's constant growth DCF analysis to reflect more recent market data?**

A. Yes. Given the recent changes in market conditions referenced in Section IV, I updated Mr. Megginson's constant growth DCF analysis to reflect market data through April 30, 2025. As shown in Exhibit A-127 (AEB-2), page 28, when Mr. Megginson's analysis is updated with current data and DTE and NJR are excluded from his proxy group, the mean cost of equity results is 10.58%.

**Q. What are your primary disagreements with Mr. Coppola's application of the constant growth DCF model?**

A. In addition to the adjustment to Mr. Coppola's proxy group discussed in Section V above, I also disagree with Mr. Coppola's reliance on the projected EPS growth rates from *Zacks* that I relied on in my direct testimony which were as of September 30, 2024. The projected EPS growth rate from *Zacks* as of September 30, 2024 are clearly outdated and should have been updated by Mr. Coppola considering his constant growth DCF analysis relies on share prices through March 17, 2025.

**Q. Have you adjusted Mr. Coppola's constant growth DCF analyses to address the issues you just discussed?**

A. Yes, I have. I modified Mr. Coppola's constant growth DCF analysis to: (1) remove CPK and BKH from his proxy group, and (2) reflect market data (i.e. share prices, dividends, and growth rates) through April 30, 2025. As shown in Exhibit A-127 (AEB-2), page 30, by making these reasonable adjustments to Mr. Coppola's constant growth DCF analysis, the mean ROE result increases by 68 basis points from 9.11% to 9.79%.

**Q. How does Mr. Walters use the results of his DCF models to establish his ROE recommendation?**

A. While his specification of the DCF analyses have not changed, Mr. Walters's use of the DCF model results to establish his ROE range has changed over time. Specifically, Mr. Walters has gone from primarily weighting his constant growth DCF using projected EPS growth rates, to generally weighting all three of his DCF analyses equally, to now in the current proceeding, stating that he gives primary weight to his constant growth DCF using sustainable growth rates and his multi-stage DCF.[74]

[74] See, e.g., Oklahoma Corporation Commission, Case No. 2021-00164, Responsive Testimony of Christopher C. Walters, April 22, 2022, at 35, 38 and Exhibit CCW-3; Oklahoma Corporation Commission, Case No. 2022-000093, Responsive Testimony of Christopher C. Walters, March 7, 2023, at 35, 38 and Exhibit CCW-3; Wyoming Public Service Commission, Docket No. 20000-633-ER-23, Direct Testimony of Christopher C. Walters, August 14, 2023 at 41, 43 and WOCA Exhibit No. 602.5; Michigan Public Service Commission, Case No. U-21389, Direct Testimony of Christopher C. Walters, August 29, 2023, at 39, 42 and Exhibit AB-14.

**Q. Why does Mr. Walters contend that primary weight should be placed on the results of his constant growth DCF model that relies on sustainable growth rates and his multi-stage DCF analyses?**

A. Mr. Walters states that he supports placing less weight on his constant growth DCF that relies on analysts' projected EPS growth rates because the average projected EPS growth rate exceeds his projected GDP growth rate.[75]

**Q. Is this rationale for the change in his approach credible?**

A. No. While Mr. Walters offers this as his current rationale for limiting the weight on his DCF models that rely on EPS growth rates, the fact is that the average projected EPS growth rates that he has relied on in prior cases referenced previously have exceeded his projected GDP growth rates in each of those cases.

**Q. Are the results of Mr. Walters' constant growth DCF using sustainable growth rates reasonable?**

A. No. As a threshold matter, Mr. Walters' constant growth DCF results using the sustainable growth rate, which range from 8.38% to 8.70%, are not reasonable as they are either below or at the very low-end of the range of comparable authorized returns for natural gas utilities in the last 40 years, including even the lowest interest rate environments. The *Hope* and *Bluefield* decisions[76], which Mr. Walters acknowledges are standards to be followed in setting a just and reasonable return, require the authorized return to be comparable to other

[75] Walters Direct, at 42.

[76] *Federal Power Commission v. Hope Natural Gas Co.*, 320 U.S. 591 (1944) ("Hope"); *Bluefield Waterworks & Improvement Co., v. Public Service Commission of West Virginia*, 262 U.S. 679 (1923) ("Bluefield").

returns available to investors in companies with similar risk. Mr. Walters' constant growth DCF results using the sustainable growth rate do not meet this standard.

**Q. Why do you disagree with Mr. Walters's constant growth DCF analysis that relies on sustainable growth rates?**

A. The use of a sustainable growth rate in the DCF suggests there is a positive relationship between future earnings and the retention ratio; however, the amount of earnings retained and not paid as dividends varies as a result of management decisions as opposed to earnings that are largely market driven. For example, management may decide to: (1) conserve cash for capital investments; (2) manage the dividend payout for the purpose of minimizing future dividend reductions; (3) manage its capital structure; or (4) signal future earnings prospects. These decisions can and do influence the amount of earnings retained versus paid out as dividends, and such decisions have been seen recently in the market. For example, due to the economic effects of COVID-19, more than 40 S&P 500 companies temporarily suspended their dividends.[77]

**Q. Is there academic research that supports your conclusion?**

A. Yes. Zhou and Ruland (2006), Gwilym, et. al. (2006) and Vivian (2006) discussed the theory that high dividend payouts (i.e. low retention ratios) are associated with low future earnings growth.[78] Each of these studies also cited Arnott and Asness (2003) that found,

[77] Karen Langley, "U.S. Companies Slashed Dividends at Fastest Pace in More Than a Decade," *The Wall Street Journal*, July 8, 2020.

[78] Ping Zhou and William Ruland, "Dividend Payout and Future Earnings Growth," *Financial Analysts Journal*, Vol. 62, No. 3, 2006; Owain Gwilym, James Seaton, Karina Suddason, and Stephen Thomas, "International Evidence on the Payout Ratio, Earnings, Dividends and Returns," *Financial Analysts Journa*l, Vol. 62, No. 1, 2006; Andrew Vivian, "The Payout Ratio, Earnings Growth Returns: UK Industry Evidence," Working Paper, School of Economics, Finance and Business, University of Durham, 2006.

over the course of 130 years of data, future earnings growth is associated with high, rather than low payout ratios.[79] Specifically, Arnott and Asness (2003) concluded:

> Unlike optimistic new-paradigm advocates, we found that low payout ratios (high retention rates) historically precede low earnings growth. This relationship is statistically strong and robust. We found that the empirical facts conform to a world in which managers possess private information that causes them to pay out a large share of earnings when they are optimistic that dividend cuts will not be necessary and to pay out a small share when they are pessimistic, perhaps so that they can be confident of maintaining the dividend payouts. Alternatively, the facts also fit a world in which low payout ratios lead to, or come with, inefficient empire building and the funding of less than-ideal projects and investments, leading to poor subsequent growth, whereas high payout ratios lead to more carefully chosen projects. The empire-building story also fits the initial macroeconomic evidence quite well. At this point, these explanations are conjectures; more work on discriminating among competing stories is appropriate.[80]

All four studies found that there is a negative, not a positive, relationship between earnings growth rates and retention ratios. As such, Mr. Walters's reliance on retention growth rates in the constant growth DCF model is not appropriate.

**Q. Are there other reasons why you believe that sustainable growth rates should not be used in the DCF model?**

A. Yes. First, the use of the sustainable or retention growth rates involves estimating investor expectations for four separate variables over the near-term: (1) the retention ratio, reflected as the "b" variable; (2) the expected return on book equity, reflected as the "r" variable;

[79] Robert Arnott and Clifford Asness, "Surprise: Higher Dividends = Higher Earnings Growth," *Financial Analysts Journal*, Vol. 59, No. 1, January/February 2003. Since the payout ratio is the inverse of the retention ratio, the authors found that future earnings growth is negatively related to the retention ratio.

[80] *Id*.

(3) the growth in the number of share of common equity, reflected as the "s" variable; and (4) the portion of the market-to-book ratio that exceeds unity, reflected as the "v" variable. This means that the growth estimate includes the forecasting error of the four separate variables.

Second, Mr. Walters relies on two growth rates that he suggests represent the long-term growth of the proxy group (i.e. the sustainable growth rate assumed in his constant growth DCF analysis and the long-term growth rate assumed in his multi-stage DCF analysis); however, these assumed growth rates are significantly different from one another and affect the results of his DCF analyses. The average long-term "sustainable" growth rate that Mr. Walters relies on in a constant growth DCF model is 5.32%.[81] Mr. Walters states that the sustainable growth rate is limited by the projected long-term GDP growth rate as that reflects the projected long-term growth in the economy as a whole, yet this growth rate is inconsistent with the long-term growth rate that he assumes in his multi-stage DCF model (i.e. 4.14%).[82]

Finally, the use of sustainable growth rates ignores the extensive academic research demonstrating that EPS growth rates are most relevant in stock price valuation.[83]

[81] Walters Direct, at Exhibit AB-11, pg. 1.

[82] *Id*., at 40.

[83] See, e.g., Robert S. Harris, "Using Analysts' Growth Forecasts to Estimate Shareholder Required Rates of Return," *Financial Management*, Spring 1986, at 66; James H. Vander Weide and Willard T. Carleton, "Investor growth expectations: Analysts vs. history," *The Journal of Portfolio Management*, Spring, 1988; Robert S. Harris and Felicia C. Marston, "Estimating Shareholder Risk Premia Using Analysts' Growth Forecasts," *Financial Management*, Summer, 1992; Advanced Research Center, "Investor Growth Expectations," Summer 2004; Eugene F. Brigham, Dilip K. Shome and Steve R. Vinson, "The Risk Premium Approach to Measuring a Utility's Cost of Equity," *Financial Management*, Vol. 14, No. 1, Spring, 1985; Dr. Roger A. Morin, *New Regulatory Finance*, Public Utilities Reports, Inc., 2006, at 299-303; Jing Liu, *et. al*., "Equity Valuation Using Multiples," *Journal of Accounting Research*, Vol. 40 No. 1, March 2002; C. A. Gleason, *et. al*., "Valuation Model Use and the Price Target Performance of Sell-Side Equity Analysts," *Contemporary Accounting Research*, September 2011; Bochun Jung, *et.. al*., "Do financial analysts' long-term growth forecasts matter? Evidence from stock

Continued on next page

**Q. Do you agree with Mr. Walters' and Mr. Bandyk's use of multi-stage DCF analyses to estimate the ROE for the Company?**

A. No, I do not. The utility industry is considered a mature industry due to its regulated status and relatively stable demand. Thus, financial projections such as earnings growth rate projections are also likely to be relatively stable over the long-term. The relative stability of the financial forecasts for utilities supports the use of a constant growth DCF model to estimate the cost of equity for a mature industry like utilities. As noted, both Mr. Megginson and Mr. Coppola also conduct constant growth DCF analyses and do not rely on a multi-stage DCF model. For these reasons, the constant growth DCF model is the more appropriate model to estimate the cost of equity for the Company rather than the multi-stage analyses conducted by Mr. Walters and Mr. Bandyk.

**Q. Do the two-stage and multi-stage forms of the DCF model increase the number of subjective inputs required to estimate the DCF model?**

A. Yes. The multi-stage DCF model introduces additional assumptions and potential analyst bias. Specifically, the multi-stage DCF models presented by Mr. Walters and Mr. Bandyk in this proceeding resulted in the following additional assumptions that require subjective judgment:

- Specification of the Model: In this case, Mr. Bandyk and Mr. Walters present two different specifications of the model (i.e. Mr. Bandyk presents a two-stage growth DCF which is a form of the constant growth DCF model but relies on a blended growth rate calculated using a weighted average of short-term and long-term growth, and Mr. Walters presents a multi-stage DCF with three stages of growth).

recommendations and career outcomes," *Journal of Accounting and Economics*, Vol. 53 Issues 1-2, February-April 2012.

- Selection of the Growth Rates: Mr. Bandyk's DCF that relies on a blended growth rate requires selecting a short-term and long-term growth rate, while Mr. Walters's multi-stage DCF with three stages of growth requires the additional selection of an intermediate growth rate.

- Weighting Factors for the Blended Growth Rate: Mr. Bandyk places 80% weight on the short-term growth rate and 20% on the long-term growth rate when calculating his blended growth rate, which is consistent with the Federal Energy Regulatory Commission ("FERC") methodology.[84] The selection of the weighting factor will have a direct effect on the result produced by Mr. Bandyk's two-stage DCF model.

- Duration of Each Stage of the Multi-Stage DCF Model: For his multi-stage DCF model with three stages of growth, Mr. Walters assumes stage 1 growth is years 1-5, stage 2 growth is years 6-10, and stage 3 growth is year 11 and after.

Given the number of additional subjective assumptions required, it is reasonable to conclude that a multi-stage DCF analysis creates greater opportunity for an analyst to influence the results of the DCF model.

**Q. How do you respond to Mr. Walters' and Mr. Bandyk's contention that the use of projected EPS growth rates is not consistent with the infinite time horizon in the DCF model?**

A. There are multiple reasons why there is no basis to Mr. Walters's and Mr. Bandyk's claims.

First, both Mr. Bandyk[85] and Mr. Walters[86] appear to support their conclusion by comparing the projected EPS growth rates to their respective projected GDP growth rates, noting that it is not reasonable to assume that utilities can grow at a rate that is greater than

[84] FERC Opinion No. 569-A, issued May 21, 2020, at P57.
[85] Bandyk Direct, at 22-23.
[86] Walters Direct, at 64-65.

the economy over the long-term. However, this comparison relies entirely on the accuracy of Mr. Bandyk's and Mr. Walters' estimate of the long-term GDP growth rate.

Second, considering the empirical studies comparing the total factor productivity ("TFP") growth of the utility industry relative to the economy, it is not unreasonable to assume that earnings growth for utilities could exceed GDP growth over the long term. In a study filed as part of the Rate Regulation Initiative of the Alberta Utilities Commission, the authors calculated TFP growth[87] for 72 U.S. electric and combination electric and natural gas utilities and for the U.S. economy for the period of 1972 through 2009. For the U.S. utility group, TFP growth averaged 0.96% over the period of 1972 to 2009,[88] while TFP growth for the U.S. economy was 0.91%,[89] indicating that electric and combination electric and natural gas utilities were approximately 5% more productive than the U.S. economy over the study period. Therefore, the authors demonstrated that utility growth exceeded growth for the U.S. economy for approximately 40 years.

**Q. Is there academic research that refutes Mr. Bandyk's and Mr. Walters' contention that the use of analysts' projected EPS growth rates is not consistent with a long-term growth rate that matches investors' expectations of the domestic economy as a whole.**

A. Yes. Both Mr. Walters and Mr. Bandyk support their conclusion that a multi-stage DCF is necessary by comparing the analysts' projected EPS growth rates to their respective projected GDP growth rates and suggests that it is not reasonable to assume that utilities

[87] TFP growth is a measure of productivity calculated as the difference between output growth and input growth. Higher TFP growth indicates that a company is converting inputs into higher levels of output growth (i.e. increased productivity).

[88] Alberta Utilities Commission, Jeff Makholm and Agustin Ros, "Update, Reply and PBR Plan Review for AUC Proceeding 566 – Rate Regulation Initiative", February 22, 2012, at 5.

[89] *Id*., at 19.

can grow at a rate that is greater than the economy over the long term. However, as noted above, there is significant academic literature that supports the use of earnings growth rates in the DCF analysis and texts that challenge the assumption of GDP growth used in a multi-stage DCF model. For example, in a recent publication, Dr. Roger Morin notes the following:

> One central assumption in Multi-Stage DCF models, and a potential Achilles' heel, in my view, is that utility growth rates will eventually match the growth of the macroeconomy usually measured by the growth of the Gross Domestic Product (GDP). I am not aware of any financial literature supporting the notion that utility earnings per share are expected to grow at the average growth of the economy, or GDP.
>
> As discussed in Chapter 10, based upon the wealth of empirical and academic literature that supports the superiority of analyst's forecasts as a measure of investor expectations for the use of such forecasts in the DCF model, current earnings growth forecasts are the appropriate growth rates to use in a DCF analysis. Besides, to the extent that economic trends influence growth, it is reasonable to assume that they are already captured in analysts' growth estimates for utilities.
>
> Multi-stage DCF applications appear somewhat disconnected from the assumptions of the method and the consensus expectations of investors. The investment community does not look to GDP growth over the next several decades when evaluating an investment in utility stocks, nor does it anticipate a series of discrete muti-stage decennial stages. I am not aware of any evidence that investors evaluate the future based on the assumptions and data sources required to apply the two-stage or three-stage DCF model.[90]

[90] Roger A. Morin, *Modern Regulatory Finance*, Public Utilities Reports, Inc., 2021, at 486.

**Q. How do Mr. Bandyk and Mr. Walters develop their projected GDP growth rates?**

A. Mr. Bandyk relies on the projected nominal GDP growth rate over the period of 2028-2035 from the Congressional Budget Office ("CBO") of 3.80%.[91] Mr. Walters relies on a projected nominal GDP of 4.14% as reported by *Blue Chip Economic Indicators*.[92]

**Q. Do you agree with Mr. Bandyk's and Mr. Walters's projected GDP growth rate?**

A. No. Mr. Bandyk relies on a projected nominal GDP growth rate from CBO for the period of 2028 to 2035. However, Mr. Bandyk's two-stage DCF analysis relies on a blended growth rate that continues into perpetuity. Therefore, the projected nominal GDP growth rate from CBO would only reflect growth for the seven-year period of 2028 through 2035, even though his two-stage DCF model extends into perpetuity. In other words, his assumed long-term growth rate only covers a small portion of the long-term period to which it is being applied in his DCF analyses. As a result, the projected GDP growth rates from CBO may not be indicative of the expected growth in GDP over the long term, and therefore, cannot be used as the basis to conclude that the projected EPS growth rate for my proxy group will not be sustained in perpetuity.

Mr. Walters relies on a projected nominal GDP growth rate of 4.14% as reported by *Blue Chip Economic Indicators,* which is only for the next 5 to 10 years. As a result, similar to the growth rate of CBO relied on by Mr. Bandyk, the projected GDP growth rate from *Blue Chip Economic Indicators* may not be indicative of the expected growth in GDP over the long term and therefore cannot be used to conclude that my projected EPS growth rates are not sustainable.

[91] Bandyk Direct, at Exhibit CUB-19.
[92] Walters Direct, at 40.

**Q. Is Mr. Walters's assumed long-term growth rate in his multi-stage DCF consistent with the analyst literature that he relies on?**

A. No. Mr. Walters's assumed long-term growth rate in his multi-stage DCF of 4.14% is inconsistent with the analyst literature he cites in his testimony. When discussing the long-term growth rate for his multi-stage DCF, Mr. Walters references the following quote from the *Ibbotson* SBBI 2013 Valuation Yearbook:

> Another approach to estimating long-term growth rates is to focus on estimating the overall economic growth rate. Again, this is the approach used in the *Ibbotson Cost of Capital Yearbook*. To obtain the economic growth rate, a forecast is made of the growth rate's component parts. Expected growth can be broken into two main parts: expected inflation and expected real growth. By analyzing these components separately, it is easier to see the factors that drive growth.[93]

However, Mr. Walters cites only a portion of the quote and omits the remainder of the discussion, which indicates that his assumed long-term growth rate is inconsistent with the approach recommended by *Ibbotson* for establishing a long-term growth rate:

> Once the long-term expected inflation rate is estimated, the real growth rate must be determined. The growth rate in real Gross Domestic Product (GDP) for the period 1929 to 2012 was approximately 3.22 percent. Growth in real GDP (with only a few exceptions) has been reasonably stable over time; therefore, its historical performance is a good estimate of expected long-term (future) performance.
>
> By combining the inflation estimate with the real growth rate estimate, a long-term estimate of nominal growth is formed.[94]

[93] *Id.,* at 39.

[94] *Morningstar, Inc*., Ibbotson SBBI 2013 Valuation Yearbook, at 52.

The *Ibbotson* SBBI 2013 Valuation Yearbook recommends that the long-term growth rate reflect the sum of the long-term historical average real GDP growth rate and the expected inflation rate. As shown in Exhibit A-127 (AEB-2), page 31, had Mr. Walters used the *Ibbotson* approach, based on the full citation, taking into consideration the real GDP growth rate and expected inflation, the resulting long-term growth is 5.45%. As a result, Mr. Walters understates the long-term growth rate consistent with *Ibbotson's* methodology that he cites in his testimony.

**Q. If Mr. Walters had appropriately included NiSource in his proxy group and placed primary weight on the results of his constant growth DCF model that relies on analysts' EPS growth rates consistent with his approach in prior proceedings, what is the resulting cost of equity?**

A. As shown in Exhibit A-127 (AEB-2), page 33, when Mr. Walters' constant growth DCF relying on analysts' projected EPS growth rates is updated to rely on a proxy group including NiSource, the median cost of equity result is 11.05%.[95]

**Q. Did you also adjust Mr. Bandyk's DCF analysis?**

A. Yes. I modified Mr. Bandyk's DCF analysis to: (1) rely on the constant growth DCF model as opposed to the two-stage DCF model; and (2) reflect market data (i.e. share prices, dividends, and growth rates) through April 30, 2025, because Mr. Bandyk was relying on the annualized dividends and projected EPS growth rates that I relied on in my direct

[95] The mean was not considered due to a projected EPS growth rate for California Water Service Group of approximately 42 percent from Zacks, S&P and I/B/E/S, which has a significant effect on the average. It is more appropriate to rely on the median which is not affected to a large degree by the presence of outliers.

testimony which are outdated.[96] As shown in Exhibit A-127 (AEB-2), page 35, by making these reasonable adjustments to Mr. Bandyk's DCF analysis, the mean ROE result increases by from 9.22% to 10.99%.

## VII. CAPM ANALYSIS

**Q. Please summarize the CAPM analyses prepared by Mr. Megginson, Mr. Coppola, Mr. Walters, and Mr. Bandyk.**

A. Mr. Megginson conducts three CAPM analyses, one using a historical market risk premium, and two additional scenarios using different implied projected market risk premia, one based on the trailing 12-month cash yield and the other based on the average cash yield over the past 10 years.[97] For all three of his CAPM analyses, Mr. Megginson relies on (1) a risk-free rate of 4.25%, which is based on a weighted average of projected 30-year Treasury bond yields for 2025 and 2026 as reported by S&P Global Market and *econforecasting.com*; and (2) current betas for each of the proxy group companies as published by *Value Line*. Mr. Megginson calculates his historical market risk premium, which is 6.94%, as the arithmetic mean realized return on large company stocks over the period 1928-2024 minus the income-only total return on long-term government bonds over that same period. For each of his CAPM scenarios relying on a projected market risk premium, Mr. Megginson relies on data reported by Professor Damodaran. The average cost of equity result of Mr. Megginson's CAPM analyses are 10.63% (historical market

[96] In my direct testimony, I relied on projected EPS growth rates from *Yahoo! Finance*; however, *Yahoo! Finance* is no longer reporting projected EPS growth rates. Therefore, when updating my constant growth DCF analysis in my rebuttal testimony, I instead relied on projected EPS growth rates from S&P Capital IQ Pro. Thus, when adjusting Mr. Bandyk's DCF analysis, I relied on projected EPS growth rates from S&P Capital IQ Pro in addition to the projected EPS growth rates from *Zacks* and *Value Line*.

[97] Megginson Direct, Exhibit No. S-4, Schedule D-5, at 8-9.

risk premium), 8.25% (12-month trailing projected market risk premium), and 9.93% (10-year projected market risk premium).[98]

Mr. Coppola conducts a CAPM analysis that relies on (1) a risk-free rate of 4.00%, based on the near-term projected 30-year Treasury bond yield as reported by *Blue Chip Financial Forecasts* as of October 1, 2024; (2) current betas for each of the proxy group companies as published by *Value Line*; and (3) a market risk premium of 7.30%, which is the historical market return of large company stocks minus the income-only return on long-term government bonds from 1926 through 2023 as published by *Kroll*.[99] The cost of equity resulting from Mr. Coppola's CAPM analysis is 10.66%.

Mr. Walters produces 12 different cost of equity estimates from his CAPM analysis, relying on different estimates of the risk-free rate, beta, and market risk premium. Specifically, for the risk-free rate, Mr. Walters relies on a projected 30-year Treasury yield in eight scenarios, and a *Kroll* "normalized" risk-free rate in the remaining four scenarios. For beta, Mr. Walters relies on four estimates for the proxy group companies: (1) current five-year betas published by *Value Line*; (2) historical average betas published by *Value Line*; (3) current beta estimates from S&P Market Intelligence's Beta Generator ("Market Intelligence"); and (4) current three-year raw betas published by Market Intelligence and then applying the Blume adjustment similar to *Value Line's* adjustment. For the market risk premium, Mr. Walters also relies on three estimates: (1) the long-term historical arithmetic average real return on the S&P 500 plus an expected inflation rate, less the risk-free rate; (2) a constant growth DCF-derived return on the S&P 500, averaging the

[98] Megginson Direct, at 27-30 and Exhibit S-4, Schedule D-5, at 7-9.
[99] Coppola Direct, at 134-136 and Exhibit AG-44.

method prescribed by FERC in Order No. 569-A with an alternative where all the companies in the S&P 500 are used rather than just the dividend-paying companies, less the risk-free rate; and (3) a "normalized" market risk premium published by *Kroll*. Mr. Walters's CAPM results produce a cost of equity range from 8.19% to 11.44%.[100]

Mr. Bandyk's CAPM analysis relies on (1) a risk-free rate of 4.41%; (2) current betas for each of the proxy group companies as published by *Value Line* and Bloomberg, but adjusted to remove the Blume adjustment reflected in those betas such that he relies on the raw betas; and (3) an estimated market risk premium that is an average of three sources: Professor Damodaran; the IESE Business School survey; and *Kroll*.[101]

**A. Risk-Free Rate**

**Q. Is the risk-free rate that Mr. Coppola relies on in his CAPM analysis reasonable?**

A. No. Mr. Coppola's risk-free rate is outdated and does not reflect current expectations and therefore should not be relied upon. Specifically, Mr. Coppola relies on a risk-free rate of 4.00% based on the *Blue Chip Financial Forecasts* as of October 1, 2024, and states that his 4.00% risk-free rate is "forecasted for the first quarter of 2026, which is about the mid-point of the projected test year."[102] However, the *Blue Chip Financial Forecast* is a monthly publication, and thus Mr. Coppola's analysis should have been based on the most recent data available. It is unclear why Mr. Coppola relies on an outdated risk-free rate that is more than six months old given the availability of more current data prior to the filing of his testimony on April 23, 2025.

[100] Walters Direct, at 49-58 and Exhibit AB-20.
[101] Bandyk Direct, Exhibits CUB-15, CUB-16, and CUB-17.
[102] Coppola Direct, at 140.

**Q. Is the current consensus estimate of the 30-year Treasury bond yield significantly different than assumed in Mr. Coppola's CAPM analysis?**

A. Yes. As reported in the most recent publication of the *Blue Chip Financial Forecasts*, the consensus estimate of the 30-year Treasury bond yield for the first quarter of 2026 as relied on by Mr. Coppola is 4.50%.[103]

**Q. Is Mr. Megginson's calculation of the risk-free rate similarly understated?**

A. Yes, at least in part. As noted, Mr. Megginson relies on two projections of the 30-year Treasury bond yield for his risk-free rate: a projection published by S&P Global Market Intelligence from IHS Markit and a projection published by *econforecasting.com*. While I do not have access to the source of Mr. Megginson's risk-free rate published by S&P Global Market Intelligence from IHS Markit, the current projections from *econforecasting.com* indicate a projected 30-year Treasury bond yield for the remainder of 2025 of 4.69%, and for calendar year 2026 of 4.12%.[104] Even assuming no change in Mr. Megginson's S&P Global Market Intelligence data, the resulting risk-free rate, when updating the *econforecasting.com* data and weighting the sources in the same manner as Mr. Megginson has in his testimony, results in a risk-free rate of 4.38% as compared to Mr. Megginson's assumed 4.25%.

[103] *Blue Chip Financial Forecasts*, Vol. 44, No. 4, April 1, 2025, at 2.
[104] *econforecasting.com*; data accessed as of April 28, 2025.

**B. Market Risk Premium**

**Q. What is the primary criticism that you have of the development of the market risk premium used by each of the witnesses recommending an ROE for the Company in this proceeding?**

A. Each of the other witnesses in this proceeding develop their market risk premium independent from the risk-free rate that they are using in their CAPM analyses, which ignores the academic research that there is an inverse relationship between the risk-free rate and the market risk premium.[105] As I will discuss, this misalignment of the risk-free rate and market risk premium in their respective CAPM analyses serves to underestimate the cost of equity.

**Q. Do you disagree with other aspects of the market risk premium assumptions developed by the witnesses in this proceeding?**

A. Yes. I also disagree with the use of the historical market risk premium, as applied by Mr. Megginson and Mr. Coppola, and I disagree with the projected market risk premium developed by Mr. Megginson and find the methodologies that he uses in this case to develop the market risk premia to be inconsistent with his prior testimony and the prior testimony of other staff members.

[105] See e.g., S. Keith Berry, "Interest Rate Risk and Utility Risk Premia during 1982-93," *Managerial and Decision Economics*, Vol. 19, No. 2, March, 1998. *See also*, Robert S. Harris, "Using Analysts' Growth Forecasts to Estimate Shareholder Required Rates of Return," *Financial Management*, Spring 1986, at 66.

**Q. Please explain why you disagree with Mr. Megginson's and Mr. Coppola's use of a historical market risk premium for estimating the CAPM.**

A. Fundamentally, the market return and market risk premium should be forward-looking. Neither Mr. Megginson nor Mr. Coppola have provided any evidence that the historical averages that they calculate for the market return or the market risk premium reflect the expected market conditions during the period in which the Company's proposed rates will be in effect. As *Morningstar* has observed, the market risk premium is a forward-looking concept, not a historical analysis:

> It is important to note that the expected equity risk premium, as it is used in discount rates and the cost of capital analysis, is a forward-looking concept. That is, the equity risk premium that is used in the discount rate should be reflective of what investors think the risk premium will be going forward.[106]

Interest rates have increased significantly since historical lows and are expected to remain elevated over at least the next year. Inflation remains above the Federal Reserve's target level, and uncertainty (i.e. overall higher risk) in the market has increased because of the effect of the current administration's policies with respect to tariffs, immigration, and taxes on the economy. All of these conditions affect the current and projected equity risk premium and should be considered in establishing the ROE in this proceeding.

[106] *Morningstar Inc*., 2010 Ibbotson SBBI Valuation Yearbook, at 55.

**Q. Are there other reasons why using a historical market risk premium for estimating the forward-looking cost of equity is not appropriate in the calculation of the CAPM based on current market conditions?**

A. Yes. As noted previously, Mr. Megginson's and Mr. Coppola's use of the historical market risk premium disregards the demonstrated relationship between interest rates and the market risk premium. Both Mr. Megginson and Mr. Coppola calculate the cost of equity using the CAPM by relying on a long-term historical average market risk premia and a near-term projected risk-free rate. However, in Mr. Megginson's and Mr. Coppola's specification of the CAPM, their respective near-term projected risk-free rates bear no relationship to the historical average interest rates underlying the historical average market risk premia on which they rely. Therefore, the use of assumptions from different time periods fails to account for the inverse relationship that exists between the risk-free rate and the equity risk premium. Both academic literature and market evidence indicate that the equity risk premium is inversely related to the level of interest rates (i.e. as interest rates increase, the equity risk premium decreases, and vice versa), and given that current interest rates on long-term government bonds are below the historical average interest rate of those same bonds, the market risk premium should be *greater than* the long-term historical average market risk premium – which is not the case for either Mr. Megginson's or Mr. Coppola's CAPM analyses.

**Q. Can you illustrate the inconsistency between Mr. Megginson's and Mr. Coppola's risk-free rate and equity risk premium?**

A. Yes. Mr. Megginson's estimate of the historical market risk premium, relies on the arithmetic average market risk premium for the period of 1928-2023 (i.e. 6.94%), which is

based on the difference between the historical average return on large company stocks (i.e. 11.79%) and the historical average income-only return on long-term government bonds (i.e. 4.85%) over this period.[107] However, Mr. Megginson relies on a near-term projected risk-free rate on long-term government bonds of 4.25% to estimate the cost of equity in the CAPM, which is *lower than* the historical average return on long-term government bonds (i.e., 4.85%) that he relies on to estimate the market risk premium. Considering the academic research that demonstrates the inverse relationship between interest rates and the market risk premium, since Mr. Megginson's current return on long-term government bonds is *less than* the historical average return on those same bonds, the current market risk premium should be *greater than* the long-term historical average of 6.94% that Mr. Megginson assumes. Consequently, Mr. Megginson's use of a historical market risk premium understates the market risk premium in the current market environment when interest rates are below the long-term average. This flaw in Mr. Coppola's analysis is even more pronounced given that he uses the same historical average return on long-term government bonds that Mr. Megginson relies on (i.e. 4.85%) to estimate the equity risk premium, but relies on an even lower forward-looking risk-free rate of 4.00%.[108] Therefore, Mr. Coppola's CAPM analysis also understates the cost of equity.

[107] Megginson Direct, Exhibit No. S-4, Schedule D-5, at 7.
[108] Coppola Direct, Exhibit AG-44.

**Q. Has *Kroll*, the publisher of the historical data on which Mr. Megginson and Mr. Coppola rely to estimate the historical market risk premium, highlighted a potential inconsistency with relying on historical data for a forward-looking analysis such as the CAPM?**

A. Yes. *Kroll* has stated that, "[i]n using a historical measure of the equity risk premium, one assumes that what has happened in the past is representative of what might be expected in the future."[109] However, because the near-term projected long-term government bond yields are currently below those that Mr. Megginson and Mr. Coppola have relied on in their historical average market risk premium estimates, the market risk premium based on long-term historical average data is certainly not representative of what is expected in the future. Given the inverse relationship between the market risk premium and interest rates, since the projected interest rate is lower than the historical average, it is reasonable to expect that the market risk premium would be higher than the historical average.

**Q. Is there also evidence that the use of a historical market premium can produce counter-intuitive results?**

A. Yes. Figure 7 illustrates the problem with relying on the historical market risk premium such as Mr. Megginson and Mr. Coppola have done. Specifically, the figure shows that from 2007-2009, the historical market risk premium decreased even as market volatility (the primary statistical measure of risk) significantly increased. Further, this figure demonstrates the significant swings in the annual equity risk premium that are averaged into the long-term historical average calculations. As shown, in 2008, the annual equity

[109] *Kroll*, 2022 SBBI Yearbook, at 198.

"premium" was actually negative, which implies a discount for equity holders relative to the cost of debt. It is incomprehensible that the perceived risk for equity was negative (implying a lower required return) in the height of the financial market collapse when the overall market return was a negative 37%. As shown, this individual observation alone, which runs counter to the theory of the equity risk premium, reduces the historical average market risk premium for the prior 80 years by 60 basis points.

**Figure 7: Historical Market Risk Premium and Market Volatility**

| | Market Volatility | Market Return | Annual Equity Premium | Long-term Average Historical Market Risk Premium[110] |
|---|---|---|---|---|
| 2007 | 17.54 | 5.49% | 0.63% | 7.10% |
| 2008 | 32.69 | -37.00% | -41.45% | 6.50% |
| 2009 | 31.48 | 26.46% | 3.47% | 6.70% |

The assumption that investors would expect or require a lower equity risk premium during periods of increased volatility is counter-intuitive and leads to unreliable analytical results. As noted earlier, the relevant objective in the application of the CAPM is to ensure that all three components of the model (i.e. the risk-free rate, the beta, and the market risk premium) are consistent with market conditions and investor perceptions. The forecasted market risk premium estimates used in my original and rebuttal CAPM analyses specifically address that concern.

[110] Ibbotson SBBI Yearbook. *Morningstar Inc*. 2008, at 28. *Ibbotson SBBI Yearbook*. *Morningstar Inc*. 2009, at 23; Ibbotson SBBI Yearbook. *Morningstar Inc*. 2010, at 23. The historical market risk premium equals the total return on large company stocks less the income-only return on long-term government securities.

**Q. Is the method that Mr. Megginson relies on for purposes of estimating his historical market risk premium consistent with Staff's prior methodology?**

A. No. The calculation of the historical average market risk premium that Mr. Megginson relies on is inconsistent with the method that Staff utilized previously in another recent proceeding. As noted, Mr. Megginson relies on a historical average market risk premium of 6.94%, which is based on a subset of the historical data reported by *Kroll*, from 1928 through 2023, plus data for 2023 and 2024 obtained from other market sources since *Kroll* has discontinued publishing the SBBI Yearbook. However, in Case No. U-21461, the Staff witness also relied on a historical market risk premium based on the data published by *Kroll*, however they used the full analytical period that *Kroll* publishes from 1926 through the current year – not arbitrarily starting in 1928 as Mr. Megginson has done in this proceeding.[111]

**Q. What is the effect of relying on a shorter historical data set than what Staff has relied on in prior cases?**

A. Relying on data starting in 1928 rather than the full data set understates the long-term market return and market risk premium. Mr. Megginson calculates a market return of 11.79% and a market risk premium of 6.94% using the truncated data set. However, on their online Cost of Capital Navigator, *Kroll* reports that the historical long-term market return for 1926 through 2024 is 12.17% and that the long-term income-only return on long-term government bonds over the same period is 4.86%, and thus the long-term

[111] Michigan Public Service Commission, Case No. U-21461, Qualifications and Direct Testimony of Joseph E. Ufolla, January 18, 2024, at 13.

historical average equity risk premium over this period is 7.31%.[112] This historical calculation is higher than Mr. Megginson's market risk premium and is consistent with the historical market risk premium on which Mr. Coppola relies for this CAPM analysis.[113] Therefore, while Mr. Megginson's and Mr. Coppola's use of a historical average market risk premium in their CAPM analyses understates the market risk premium and thus understates the cost of equity by failing to account for current market conditions and the inverse relationship between interest rates and the market risk premium, Mr. Megginson has further understated the historical average market risk premium, and thus cost of equity, by arbitrarily not relying on the entire historical data set published by *Kroll*.

**Q. Mr. Megginson also calculates two CAPM analyses using projected market risk premia. Are these analyses reasonable?**

A. No. First, as a threshold matter, the first of Mr. Megginson's CAPM analyses that relies on the 12-month trailing market risk premium of 4.35% results in a cost of equity of 8.25%, which is unreasonable,[114] as it is well below the low end of any authorized ROE in a comparable regulatory jurisdiction for a natural gas utility since at least 1980. Moreover, his CAPM scenarios that rely on projected market risk premia are also inconsistent with the inverse relationship between the risk-free rate and the market risk premium, and, as a result, significantly understate the cost of equity. Specifically, Mr. Megginson relies on a risk-free rate of 4.25%, which is well below the historical average return on long-term government bonds (i.e. 4.85%), which means that one would expect Mr. Megginson's

[112] *Kroll*, Cost of Capital Navigator, Historical Long-Term (1926-2024) equity risk premium; https://costofcapital.kroll.com/coc-inputs/rfr-and-erp.

[113] Coppola Direct, Exhibit AG-44; see "Sources, column (d)."

[114] Megginson Direct, Exhibit No S-4, Schedule D-5, at 8.

projected market risk premia to be *greater than* the long-term historical average market risk premium of 7.31%; however, Mr. Megginson's projected market risk premia are nearly 300 basis points and more than 110 basis points, respectively, below the long-term historical average.[115]

**Q. Is Mr. Megginson's projected market risk premium consistent with his prior testimony?**

A. No. In the recent Michigan Gas Utilities proceeding in Case No. U-21540, Mr. Megginson relied on a projected market risk premium as calculated in the same manner as I have done in my direct testimony (i.e. the projected return on the S&P 500 less the assumed risk-free rate).[116] In addition, in the Company's last electric division rate proceeding in Case No. U-21585, Mr. Megginson also relied on a similar approach, although he used an outdated market risk premium based on data filed more than 16 months prior in another rate proceeding.[117] Mr. Megginson has provided no basis for his change in approach in this proceeding.

[115] *Id*., at 8-9.

[116] Qualifications and Direct Testimony of Kirk D. Megginson, Case No. U-21540, July 1, 2024, Exhibit No. S-4, Schedule D-5, at 6 of 11. Note, the heading in column (e) of this exhibit mistakenly refers to the market risk premium as a "historical market risk premium;" however, the exhibit is clear that the market risk premium assumed by Mr. Megginson is a projected market risk premium consistent with the method relied on by the company in that proceeding.

[117] Direct Testimony of Kirk D. Megginson, Case No. U-21585, September 27, 2024, Exhibit No. S-4, Schedule D-5, at 8, whereby Mr. Megginson referenced and relied on the market risk premium in the Direct Testimony of Todd A. Wehner, Case No. U-21389, May 1, 2023, Exhibit No. A-14, Schedule D-5, page 10 of 12.

**Q. Does this change in Mr. Megginson's approach when using a projected market risk premium produce a significantly different result for his projected market risk premium?**

A. Yes. If Mr. Megginson had calculated the market risk premium in a manner consistent with his prior testimony in Case No. U-21540, his projected market risk premium would be 7.79% (i.e. the market return of 12.04% as shown in my direct testimony in Exhibit No. A-14, Schedule D-5, page 16, minus Mr. Megginson's assumed risk-free rate in this proceeding of 4.25%), or *nearly 350 basis points higher* than the 4.35% that he assumes for his projected market risk premium in the current proceeding.

**Q. Do the market risk premia relied on by Mr. Walters and Mr. Bandyk suffer from the same failure to appropriately reflect the inverse relationship between interest rates and the market risk premium as you previously discussed in your response to Mr. Megginson and Mr. Coppola?**

A. Yes. As shown in Figure 8, Mr. Walters' four CAPM analyses that rely on his *Kroll* "normalized" market risk premium, as well as the assumed market risk premium in Mr. Bandyk's CAPM analysis, which reflects an average of his three sources (i.e. Professor Damodaran; the IESE Business School survey; and *Kroll*), are also inconsistent with the inverse relationship between interest rates and the market risk premium and thus understates the cost of equity. Specifically, the risk-free rate assumptions used in their CAPM analyses are either below or consistent with the long-term average risk-free rate, and yet contrary to the inverse relationship between interest rates and the market risk premium, their respective market risk premia are well below the long-term term average market risk premium.

**Figure 8: Misalignment of Market Risk Premia Relied on by Mr. Walters and Mr. Bandyk[118]**

| Witness | Source | Market Risk Premium | Amount Below Long-Term Avg. | Risk-Free Rate | Amount Below Long-Term Avg. |
|---|---|---|---|---|---|
| | **Long-Term Historical Avg.** | **7.31%** | | **4.86%** | |
| Walters | *Kroll* - Normalized | 5.00% | -2.31% | 4.78% | -0.08% |
| Bandyk | Damodaran (TTM sustainable payout) | 4.43% | -2.88% | 4.24% | -0.62% |
| Bandyk | Damodaran (TTM) | 4.61% | -2.70% | 4.24% | -0.62% |
| Bandyk | Damodaran (smoothed) | 5.91% | -1.40% | 4.24% | -0.62% |
| Bandyk | Damodaran (normalized) | 4.07% | -3.24% | 4.24% | -0.62% |
| Bandyk | Damodaran (net cash yield) | 4.33% | -2.98% | 4.24% | -0.62% |
| Bandyk | IESE Survey | 5.70% | -1.61% | 4.10% | -0.76% |
| Bandyk | *Kroll* | 5.00% | -2.31% | 4.88% | 0.02% |

**Q. Are there other issues with the data used by Mr. Walters and Mr. Bandyk?**

A. Yes. Both Mr. Walters and Mr. Bandyk rely on outdated estimates of the market risk premium. Both witnesses use a *Kroll* projected risk premium of 5.00% as part of their respective CAPM analyses; however, the current forecasted market risk premium by *Kroll* is 5.50%.[119] Furthermore, as shown in Figure 8 above, Mr. Bandyk relies on five different estimates from Professor Damodaran for purposes of deriving an average market risk premium; however, these data are from September 2024, and are therefore more than eight months old and do not reflect current market conditions.[120]

[118] *Kroll*, Cost of Capital Navigator, Historical Long-Term (1926-2024) equity risk premium; https://costofcapital.kroll.com/coc-inputs/rfr-and-erp.

[119] *Kroll*, Cost of Capital Navigator, https://costofcapital.kroll.com/coc-inputs/rfr-and-erp. Mr. Bandyk also states on page 16 of his testimony that he relies on data from September 2024 for estimating his market risk premium; however, it appears that is in error as Exhibit CUB-16 indicates that the data was accessed as of April 2025.

[120] Bandyk Direct, at 16.

**Q. Are the results of either Mr. Walters's CAPM analyses that rely on the *Kroll* "normalized" market risk premium or Mr. Bandyk's CAPM reasonable?**

A. No. The cost of equity results from their CAPM analyses are unreasonable. Specifically, the results of Mr. Walters's *Kroll* "normalized" market risk premium CAPM scenarios are 8.19%, 8.57%, 8.72%, and 9.17%,[121] while the results of Mr. Bandyk's CAPM analysis is 7.95%. Due to their misspecification of the market risk premium in these scenarios, all of these results are either at or well below the low end of any authorized ROE in a comparable regulatory jurisdiction for a natural gas utility in nearly half a century. I recognize that Mr. Bandyk believes it is not appropriate to compare his CAPM result to previously authorized ROEs given that he claims that regulatory commissions have consistently authorized ROEs well in excess of the cost of equity for decades; however, as I have discussed, his position is unsupported and unfounded given the obligation of regulatory commissions to authorize just and reasonable rates.

**Q. What are your concerns with Mr. Walters' "forward-looking" risk premium-derived market return and thus market risk premium?**

A. I disagree with what Mr. Walters considers a "forward-looking" estimate of the market return. Mr. Walters calculates what he terms a "forward-looking" estimate of the market return, which reflects the long-term historical arithmetic average real return of the S&P 500 from 1926 through 2023 of 9.02% plus a projected inflation rate based on the Consumer Price Index of 2.50% as reported by *Blue Chip Financial Forecasts* as of February 28, 2025.[122] From this market return of 11.75%, Mr. Walters then subtracts his

[121] Walters Direct, Exhibit AB-20, at 1.
[122] Walters Direct, at 53.

projected risk-free rate of 4.60% to estimate a market risk premium that he then uses in four of his 12 CAPM scenarios.[123]

**Q. Why do you disagree with Mr. Walter's "forward-looking" risk premium-based estimate of the market return?**

A. Mr. Walters's risk premium-derived estimate of the market return is neither "forward-looking" nor does it reflect the current and expected market conditions during which the Company's rates will be in effect. First, while Mr. Walters characterizes his market return as "forward-looking," which presumably is to recognize that the market return estimate of the CAPM should be forward-looking, simply applying a projected inflation rate to a long-term historical average market return does not produce a "forward-looking" market return. Second, while Mr. Walters' use of the average real return of the S&P 500 from 1926 through 2023 is reflective of the returns realized by investors under different market and economic conditions, it is not necessarily reflective of the market return required by investors in the current and expected market environment. Mr. Walters provides no evidence that the historical average market return is reflective of the expected market conditions during the period in which the Company's proposed rates will be in effect.

**Q. Have you identified inconsistencies in the analyses prepared by Mr. Bandyk?**

A. Yes. The assumptions used in Mr. Bandyk's CAPM are inconsistent with the results of his DCF analyses. As shown in Figure 9, in four of the five estimates of the market risk premium on which Mr. Bandyk relies from Professor Damodaran, the market risk premium

[123] *Id*.

reflects an implied *market* return that ranges from 8.31% to 8.35%, which are all lower than his average DCF result for his proxy group of natural gas distribution companies of 9.22%.[124] This result is counterintuitive, as it is reasonable to expect that the return on the overall market, with a presumed beta of 1.0, would be higher than the return on Mr. Bandyk's proxy group of natural gas utilities, which he assumes have an average beta coefficient of 0.81 (*Value Line*) and 0.64 (*Bloomberg*) in his CAPM analysis. However, as shown in Figure 9, the results of Mr. Bandyk's analyses indicate the exact opposite of the expected risk/return trade off. As shown in Figure 9, Mr. Bandyk's overall market return is lower than the return he estimates for the natural gas utility proxy group, despite the expectation that this proxy group has lower overall risk than the market.

**Figure 9: Mr. Bandyk's Implied Market Return in the CAPM Analysis as Compared to His DCF Results**

| | Mr. Bandyk CAPM Assumptions | | | | Mr. Bandyk |
|---|---|---|---|---|---|
| Source | Market Risk Premium | Risk-Free Rate | Implied Return for the *Market* | | DCF Return for *Gas Utilities* |
| Damodaran (TTM sust. payout) | 4.43% | 4.24% | 8.67% | | 9.21% |
| Damodaran (TTM) | 4.61% | 4.24% | 8.85% | | 9.21% |
| Damodaran (normalized) | 4.07% | 4.24% | 8.31% | v. | 9.21% |
| Damodaran (net cash yield) | 4.33% | 4.24% | 8.57% | | 9.21% |

**Q. Is it reasonable for Mr. Bandyk to have relied on the IESE Business School survey as an estimate of the market risk premium?**

A. No. It specifically states in the IESE Business School survey that the average of the distribution of the required equity premium from the survey, which Mr. Bandyk relies on,

[124] Bandyk Direct, at 12 and Exhibit CUB-18.

*cannot be interpreted as the required equity premium of the market nor of a representative investor*.[125]

Further, there are several other academic sources that caution against the use of survey data:

- The drawbacks of survey data include biased responses and biased sampling as noted by Brigham, Shome, and Vinson (1985).[126]
- Professor Damodaran, who Mr. Bandyk also relies on for his other market risk premium estimate, noted that survey results were affected by how the questions were asked in the survey and on recent stock price movements.[127]
- The response rates to surveys can be limited, as Graham and Harvey (2018) noted in their CFO survey where the response rate was only 5% to 8%.[128]

### C. Beta Coefficients

**Q. What are the primary areas where you disagree with the betas used by the witnesses in this case?**

A. I disagree with Mr. Bandyk's reliance on raw betas, and Mr. Walters' reliance on betas from S&P Market Intelligence that reflect a Vasicek adjustment whereby the raw beta is adjusted to assume that a company's beta coefficient will trend toward the *industry* average as opposed to the *market* average of 1.0.

[125] Pablo Fernandez, Diego Garcia de la Garza, and Lucia Fernandez Acin, "Survey: Market Risk Premium and Risk-Free Rate used for 96 countries in 2024," IESE Business School, March 11, 2024, at 11; emphasis added.

[126] Eugene F. Brigham, Dilip K.Shome, and Steve R. Vinson, "The Risk Premium Approach to Measuring Utility's Cost of Equity," *Financial Management*, Vol. 14, No. 1, 1985, at 33.

[127] Aswath Damodaran, "Equity Risk Premiums (ERP): Determinants, Estimation, and Implications," March 23, 2023, at 28.

[128] John R. Graham and Campbell R Harvey, "The Equity Risk Premium in 2018," *Social Science Research Network*, March 27, 2018.

**Q. Why you do you disagree with these betas relied on by Mr. Bandyk and Mr. Walters?**

A. The use of either raw betas as Mr. Bandyk has utilized or the Vasicek-adjusted betas that Mr. Walters has utilized is not appropriate for regulated utilities because these beta coefficients likely understate the true beta of utility stocks given that the utility sector is not only correlated to the broader market, but is also sensitive to changes in interest rates, which are *not* factored into either the raw beta or Vasicek-adjusted beta calculations. Therefore, neither of Mr. Bandyk's raw beta coefficients nor Mr. Walters's Vasicek-adjusted betas consider interest rate risk and likely understate the actual risk, which in turn understates the result of the CAPM analysis. Conversely, the Blume adjustment applied by *Value Line* and *Bloomberg* adjusts the raw beta coefficients toward the market average of 1.0, thus likely better reflecting the true beta of the utility sector inclusive of interest rate risk.

**Q. Do any of the other witnesses in this proceeding rely on the raw beta coefficients that Mr. Bandyk has relied on for his CAPM analysis?**

A. No. Mr. Megginson, Mr. Coppola, Mr. Walters, and I have all relied on beta coefficients that have been adjusted using the Blume adjustment for purposes of our CAPM analyses, and as discussed, Mr. Walters has also relied on betas in one scenario adjusted using the Vasicek adjustment.

**D. <u>Response to Intervenor Positions</u>**

**Q. What are the positions of Mr. Megginson, Mr. Coppola, Mr. Walters, and Mr. Bandyk regarding your CAPM analysis?**

A. These witnesses offer the following positions regarding my CAPM analyses:

- Mr. Coppola alleges that my use of multiple risk-free rates "seems to be a hunt for an approach that will result in a higher ROE rate."[129]

- Mr. Megginson, Mr. Coppola, Mr. Walters, and Mr. Bandyk contend that my market risk premium is excessive, with Mr. Walters and Mr. Bandyk suggesting that I should have considered multiple methodologies to estimate the expected market return and market risk premium.[130]

- Mr. Coppola also contends that a problem with my calculation of the market return is that there are many companies with dividend yields and long-term growth estimates that are omitted.[131]

**Q. Is your use of three different risk-free rates an intentional attempt to achieve a higher CAPM result as Mr. Coppola alleges?**

A. No. There is no basis to Mr. Coppola's claim that I have intentionally selected three risk-free rates in an attempt to increase the resulting cost of equity from the CAPM. The Company's authorized ROE should be a forward-looking estimate of the cost of equity, and, as stated in my direct testimony, I have relied on a current risk-free rate, a near-projected risk-free rate, and a longer-term risk-free rate consistent with estimating a forward-looking cost of equity. While Mr. Coppola suggests my use of a longer-term projected risk-free rate is used to achieve a specific result, it is important to note that the long-term risk-free rate is the lowest of the three risk-free rates that I have relied upon in my analyses. Therefore, it is inconceivable that I would have relied on this projection to increase the results of my analyses.

[129] Coppola Direct, at 140.
[130] Megginson Direct, at 23; Bandyk Direct, at 17-18; Walters Direct, at 67.
[131] Coppola Direct, at 141.

**Q. Is there any basis to the claims by Mr. Megginson, Mr. Walters, or Mr. Bandyk regarding your market return and thus market risk premium?**

A. No. There are multiple reasons why there is no basis to their contention regarding the market return and thus market risk premia used in my CAPM analyses. As discussed, the market return used in my CAPM analyses is reasonable, consistent with the range established by historical market return data,[132] and has been relied upon in other regulatory jurisdictions.

First, as shown in Figure 7 of my direct testimony, an expected market return of 12.04% is reasonable given that the realized total equity return was at least at this level or greater in 52 out of the past 98 years (i.e. 53% of the observations). In addition, as reflected in Exhibit A-127 (AEB-2), pages 15-20, the forward-looking market return has declined slightly since the filing of my direct testimony and is currently 11.92%.

Second, in a cost of capital proceeding for the electric utilities in California, the California Public Utilities Commission ("California PUC") noted that all parties recognized historical market returns, and economically logical projections, fall within the range of 12%.[133]

Third, various state utility regulatory commissions have supported the use of a constant growth DCF model to estimate the market return in the CAPM such as I have done. As shown in Figure 10, the Staff of the Illinois Commerce Commission ("ICC"), the Bureau of Investigation and Enforcement ("I&E") of the Pennsylvania Public Utility

[132] Bulkley Direct, at 42-43.

[133] California Public Utilities Commission, Application No. 22-04-008, Decision No. 22-12-031, December 15, 2022, at 23.

Commission ("Pennsylvania PUC"), and the Staff of the Maine Public Utilities Commission ("Maine PUC") have each supported the forward-looking market risk premium, and the market return estimates using the constant growth DCF model. In each of these cases, the respective regulatory commission relied on the estimated CAPM results by these parties to determine the authorized ROE and did not dispute the use of the constant growth DCF model to calculate the market return.

**Figure 10: Examples of Jurisdictions Where Market Return Estimated Using the Constant Growth DCF Model**

| Intervening Party | Applicant | Docket No. | Approach of Intervening Party to Calculating the Market Return | Date of Order | Did the Commission Rely on the Intervening Party's CAPM? |
|---|---|---|---|---|---|
| Staff of the ICC | North Shore Gas Company | 20-0810 | Constant growth DCF of the dividend-paying companies in the S&P 500 (11.95%)[134] | 9/8/21 | Yes[135] |
| I&E | Aqua Pennsylvania, Inc. | R-2021-3027385 | CGDCF of the Value Line Universe and S&P 500 (12.14%)[136] | 5/12/22 | Yes, the regulator placed primary weight on I&E's CAPM[137] |
| Staff of the Maine PUC | Northern Utilities, Inc. | 2019-00092 | CGDCF of the dividend-paying companies in the S&P 500 (11.33%-13.49%)[138] | 4/1/20 | Yes[139] |

Fourth, the Federal Reserve Bank of New York published an analysis in 2015 that reviewed 20 methodologies over the period 1960 through 2013 for estimating the market risk premium. The result of this study demonstrates that my market risk premium

134 Illinois Commerce Commission, Docket No. 20-0810, Order, September 8, 2021, at 71.

135 *Id*., at 86-87.

136 Pennsylvania Public Utility Commission, Docket No. R-2021-3027385, Opinion and Order, May 16, 2022, at 147.

137 *Id*. at 178.

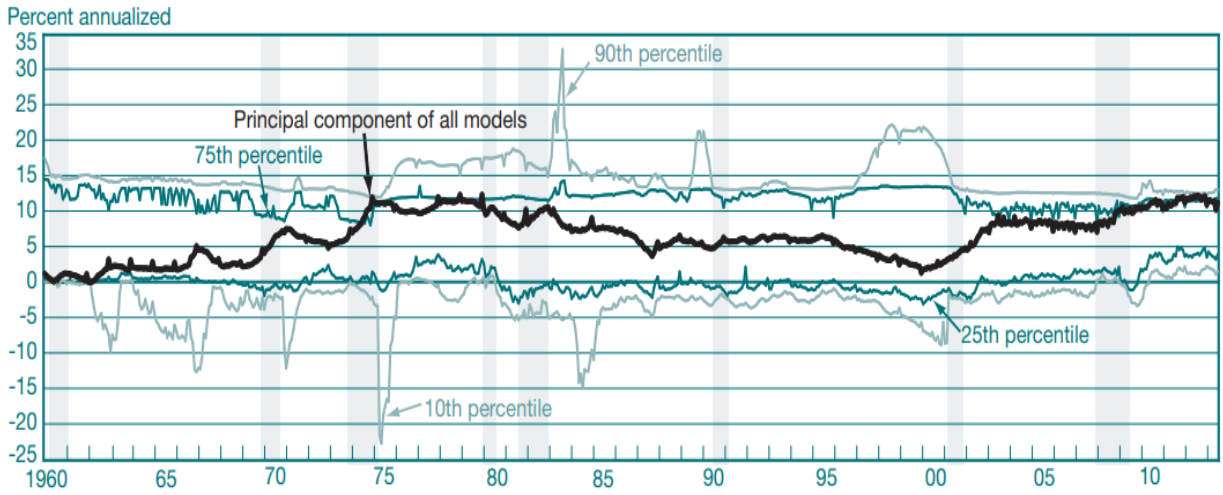
138 Maine Public Utilities Commission, Docket No. 2019-00092, Bench Analysis, October 29, 2019, at 21.

139 *Id*., Order Part II, April 1, 2020, at 58.

estimates, which, as shown on Exhibit A-127 (AEB-2), pages 5-13, of my rebuttal cost of equity analyses, are in the range of 7.24% to 7.62%, are reasonable. Specifically, the key conclusions from this study are:

- The 20 methodologies reviewed reflected a range for the market risk premium of between -1.0% to 14.5%.
- As shown in Figure 11, the principal component analysis of the 20 models (i.e. the bold black line) produced a range for the market risk premium of approximately 0% to over 10% from 1960 through 2013.
- The one-year-ahead market risk premium was consistently greater than 10% following the financial crisis of 2008/09.

**Figure 11: The Federal Reserve Bank of New York, One-Year-Ahead Market Risk Premium[140]**




Further, the Federal Reserve Bank of New York also noted the following:

> Chart 2 shows the first principal component of all twenty models in black (the black line is the same principal component shown in black in each of the panels of Chart 1). ***As expected, the principal component tends to peak during financial turmoil, recessions, and periods of low real GDP growth or high inflation***. It tends to bottom out after periods

[140] Fernando Duarte and Carla Rosa, "The Equity Risk Premium: A Review of Models," Federal Reserve Bank of New York, 2015, at 50.

> of sustained bullish stock markets and high real GDP growth. Evaluated by the first principal component, the one-year ahead ERP [*equity risk premium*] reaches a local peak in June 2012 at 12.2 percent. The surrounding months have ERP estimates of similar magnitude, with the most recent estimate in June 2013 at 11.2 percent. This behavior is not so clearly seen by simply looking at the collection of individual models in Chart 1, a finding that highlights the usefulness of principal component analysis. Similarly high levels were observed in the mid- and late 1970s, during a period of stagflation, while the recent financial crisis had slightly lower ERP estimates, closer to 10 percent.[141]

Thus, the Federal Reserve Bank of New York noted that the market risk premium is higher during periods of increased inflation. As discussed at length in my direct testimony as well as herein, inflation remains well above the Federal Reserve's target of 2% and is expected to remain elevated over the near term. Given the results of the analysis conducted by the Federal Reserve Bank of New York, it is clear that my estimates of the market risk premium are reasonable.

Lastly, it is also important to note that, despite their criticisms:

- Mr. Walters calculates a market risk premium using a forward-looking single stage DCF analysis in this proceeding (which are both higher than in my direct testimony).[142]

- As discussed previously, Mr. Megginson has conducted a CAPM scenario using a forward-looking single stage DCF analysis in prior cases and offers no discussion as to why he has changed his methodology in this proceeding.

- Mr. Coppola relies on a historically based market risk premium of 7.30%, which is not materially different than the market risk premium of 7.74% in my direct testimony. In fact, while Mr. Coppola inappropriately compares the results of his CAPM analysis to the highest result of my CAPM analysis, the resulting

[141] *Id*.; emphasis and clarification added.

[142] As shown in Exhibit AB-20, the market return in his analysis is 12.48% and the market risk premium is 7.90%, which are both higher

cost of equity from Mr. Coppola's CAPM is 10.66%, which is higher than the average of all of my CAPM analyses in my direct testimony of 10.43%.[143]

Therefore, for all of the reasons just discussed, the market return, and thus market risk premium, in my CAPM analyses are reasonable and consistent with the findings of the Federal Reserve and other utility regulatory commissions, and there is no basis for the claims that the market return, and thus market risk premium, in my CAPM analyses is excessive.

**Q. Have courts addressed these witnesses' assertion that your forward-looking market return is inflated?**

A. Yes. In its review of FERC Opinion No. 569-B, the U.S. State Court of Appeals for the District of Columbia addressed the concern regarding the use of projected EPS growth rates in a constant growth DCF model to estimate the market return. In the Court's decision, it acknowledged that FERC has relied on the use of projected EPS growth rates in the calculation of the market return on the S&P 500 because the S&P 500 is regularly updated to include companies with high market capitalization and it includes companies at all stages of growth, including lower and higher growth potential. The Court determined that FERC's rationale for using projected EPS growth rates was sufficient and did not accept the challenge to this assumption.[144]

[143] Coppola Direct, at 139 and Exhibit AG-44; Bulkley Direct, at 48.

[144] United States Court of Appeals, District of Columbia Circuit, Opinion, Docket No. 16-1325, August 9, 2022, at 19.

**Q. Mr. Coppola also suggests that there is a concern with your market return in that certain companies have been omitted. Is there any merit to Mr. Coppola's contention?**

A. No. Mr. Coppola's suggestion that my calculation of the market return on the S&P 500 Index results in a modified population of companies that is inconsistent with the S&P 500 Index or the equity markets is incorrect. As shown on Exhibit A-14, Schedule D-5, of my direct testimony, companies in the S&P 500 Index are only excluded from my constant growth DCF analysis if their projected EPS growth rate was either negative or greater than 20%. While I believe that the calculation of the weighted projected earnings growth rate for the S&P 500 Index should include all of the companies in the index, my calculation of the market return for the CAPM and ECAPM excludes companies in the S&P 500 Index that have a long-term earnings growth rate that is negative or greater than 20% to address previously raised concerns by parties regarding the use of a constant growth DCF model relying on projected EPS growth rates.

**E. <u>Adjusted CAPM Results</u>**

**Q. Have you recalculated the CAPM analyses of Mr. Megginson, Mr. Coppola, Mr. Walters, and Mr. Bandyk to address your concerns with their reliance on a historical market risk premium?**

A. Yes, I have adjusted their respective CAPM analyses to address the issues that I have discussed:

- As noted, Mr. Megginson relies on both a historical market risk premium and projected market risk premia for his CAPM analysis.
  - First, rather than relying on the historical market risk premium for the reasons discussed, I have adjusted Mr. Megginson's CAPM analysis to

calculate the market risk premium as the historical arithmetic average market return from 1926 through 2023 minus his estimate of the risk-free rate. While I do not agree with the use of the historical market return as the estimate of the forward-looking market return for the reasons discussed, a calculation that at least derives the market risk premium from the risk-free rate that is being used in the CAPM to estimate the cost of equity is more appropriate than the calculation performed by Mr. Megginson. This is because the derived market risk premium will reflect an inverse relationship between interest rates and the market risk premium that is established in the CAPM equation (i.e. because near-term interest rates are lower than the long-term historical average, the market risk premium should be greater than the historical average risk premium). As shown on Exhibit A-127 (AEB-2), page 37, when the market risk premium is adjusted as just discussed, the average cost of equity for Mr. Megginson's CAPM analysis is 11.53%, which is an increase of 90 basis points from his as-filed position.

- Second, given that Mr. Megginson's approach for his projected market risk premia is inconsistent with his prior testimony, I have updated his CAPM analysis to rely on a projected market risk premium consistent with his prior approach. As shown on Exhibit A-127 (AEB-2), page 38, this results in a cost of equity of 11.41%.

- Therefore, whether using Mr. Megginson's historical market risk premium or his prior approach of a projected market risk premium, the cost of equity results support the reasonableness of the Company's proposed ROE in this proceeding.

- I have also adjusted the market risk premium for Mr. Coppola's CAPM analysis in the same manner as I just discussed regarding Mr. Megginson's CAPM analysis, and I have also updated Mr. Coppola's risk-free rate through April 30, 2025. As shown on Exhibit A-127 (AEB-2), page 40, this results in a cost of equity of 11.50%, which fully supports the reasonableness of the Company's proposed ROE in this proceeding.

- As discussed, four of Mr. Walters's 12 CAPM scenarios rely on a *Kroll* "normalized" market risk premium that does not properly reflect the inverse relationship between interest rates and the market risk premium. When those scenarios of Mr. Walters's CAPM analyses are excluded for this reason, the average result of his remaining eight CAPM scenarios is 10.38%, which

supports the reasonableness of the Company's proposed ROE in this proceeding.

- Mr. Bandyk's projected market risk premium also is inconsistent with the inverse relationship between interest rates and the market risk premium. As a result, I have adjusted Mr. Bandyk's CAPM analysis to rely on the projected market return of 12.04% that I relied on in my direct testimony, which is a more reasonable estimate of the market return than the implied market return based on the market risk premia in his CAPM analysis. As shown on Exhibit A-127 (AEB-2), page 42, making this adjustment produces a cost of equity result of 9.99%, or approximately 200 basis points higher than Mr. Bandyk's as-filed position. At a minimum, this supports the reasonableness of an increase in the Company's ROE for this proceeding. I also do not agree with Mr. Bandyk's use of raw betas for the reasons discussed; however, I have not adjusted his betas for purposes of the analysis shown on Exhibit A-127 (AEB-2), page 42.

## VIII. ECAPM ANALYSIS

**Q. Please summarize the positions of Mr. Megginson, Mr. Coppola, Mr. Walters, and Mr. Bandyk regarding your ECAPM analyses.**

A. Mr. Megginson, Mr. Coppola, and Mr. Walters suggest that the use of an adjusted beta in the ECAPM analysis is duplicative, as the weighting adjustments applied in the ECAPM are mathematically the same as adjusting beta, and thus the ECAPM produces a result that is overstated.[145] In addition, Mr. Megginson and Mr. Coppola also claim that the use of long-term interest rates as the risk-free rate is inconsistent with the ECAPM.[146] Mr. Bandyk states that he has not conducted an ECAPM since the Staff has historically declined using an ECAPM and the Commission has not previously recognized the ECAPM as a valid methodology.[147]

[145] Megginson Direct, at 31-33; Coppola Direct, at 142-143; Walters Direct, at 68-71.
[146] Megginson Direct, at 31; Coppola Direct, at 142-143.
[147] Bandyk Direct, at 21.

**Q. Is it appropriate to use adjusted betas in the ECAPM?**

A. Yes, it is entirely appropriate to use adjusted betas in the ECAPM, and doing so is consistent with academic literature and the estimation of the ECAPM in this manner has been accepted by various regulatory commissions. There is no merit to any of these witnesses' contentions regarding the ECAPM.

**Q. What is the purpose of using adjusted betas in the ECAPM?**

A. The purpose of adjusting beta in the CAPM is to account for the tendency of beta to trend back over time to the market beta of 1.00. As noted by Mr. Megginson, the betas published by *Value Line* include this adjustment,[148] which was first proposed by Marshall E. Blume in 1975.[149] The use of adjusted betas in the CAPM is important because if beta trends towards 1.00, as Blume noted, then the adjusted beta will be more reflective of the beta that can be expected over the near-term. This is equally important in the specification of the CAPM in this case since the cost of equity for the Company is being estimated over the near term.

The ECAPM does not account for the tendency of beta to trend toward 1.00. The purpose of the ECAPM is to account for the fact that the risk-return relationship is flatter than what is estimated by the CAPM, ***even when using adjusted betas***. While beta is not observable and must be estimated, the theory behind the ECAPM is that even if the true value of a stock's beta were observable, the CAPM would understate the results for stocks with betas less than 1.00 and overstate the results for stocks with betas greater than 1.00.

[148] Megginson Direct, at 32.

[149] Marshall E. Blume, "Betas And Their Regression Tendencies," *The Journal of Finance*, Vol. 30, No. 3, 1975, at 785-795.

Therefore, contrary to the assertions of Mr. Megginson, Mr. Coppola, and Mr. Walters, the purpose of each adjustment is different and thus applying both adjustments in the ECAPM is not duplicative.

**Q. Mr. Coppola cites a chapter in Dr. Morin's text *New Regulatory Finance* to support his view that there is academic disagreement with the studies that led to the use of the ECAPM.[150] Do you agree with Mr. Coppola's conclusion from this text?**

A. No. Reviewing the excerpt provided by Mr. Coppola, it is clear that, while Dr. Morin identifies some who have argued that the use of ECAPM is inconsistent with the use of adjusted betas, Dr. Morin further explains that the argument that has been used to support this concern is erroneous. Importantly, Dr. Morin's text fully supports the use of adjusted betas in the ECAPM and explains why it is appropriate:

> Some have argued that the use of the ECAPM is inconsistent with the use of adjusted betas, such as those supplied by Value Line and Bloomberg. This is because the reason for using the ECAPM is to allow for the tendency of betas to regress toward the mean value of 1.00 over time, and, since Value Line betas are already adjusted for such a trend, an ECAPM analysis results in double-counting. This argument is erroneous. Fundamentally, the ECAPM is not an adjustment, increase or decrease, in beta. This is obvious from the fact that the expected return on high beta securities is actually lower than that produced by the CAPM estimate. The ECAPM is a formal recognition that the observed risk-return tradeoff is flatter than predicted by the CAPM based on myriad empirical evidence. The ECAPM and the use of adjusted betas comprise two separate features of asset pricing. Even if a company's beta is estimated accurately, the CAPM still understates the return for low-beta stocks. Even if the ECAPM is used, the return for low-beta securities is understated if the betas are understated…***Both adjustments are necessary. Moreover, recall from Chapter 3 that the use of adjusted betas compensates for interest***

[150] Coppola Direct, at 142-143.

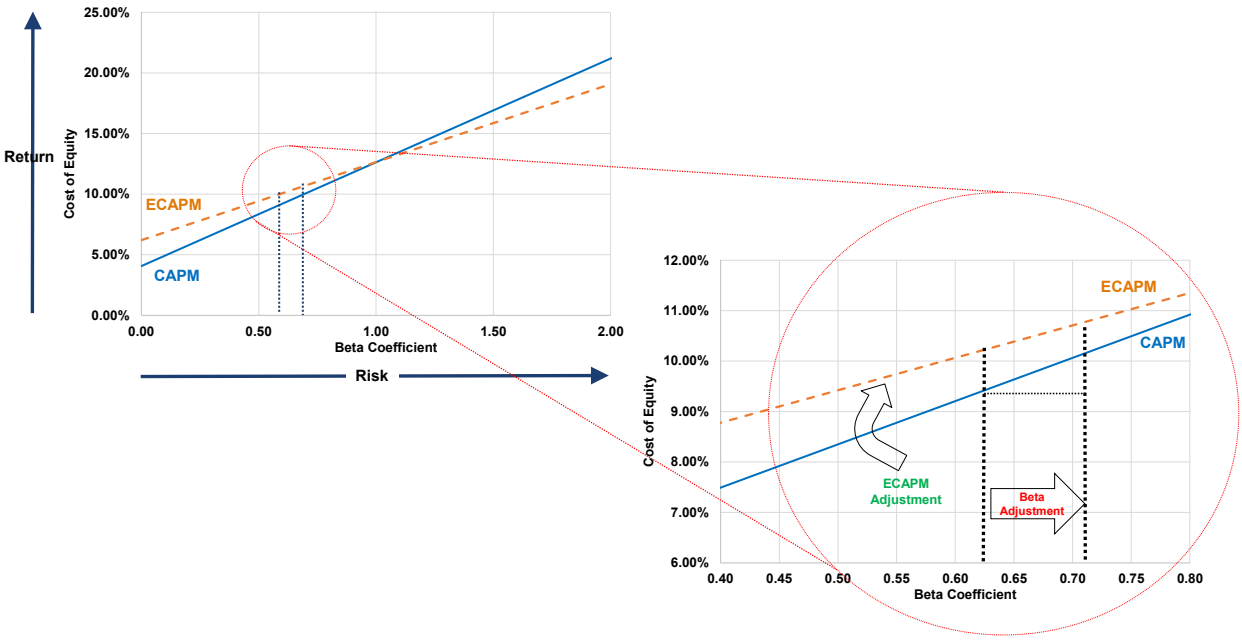
***rate sensitivity of utility stocks not captured by unadjusted betas***.[151]

**Q. Can you demonstrate that using adjusted betas in the CAPM and relying on the ECAPM are two distinct adjustments to the CAPM?**

A. Yes. Figure 12 demonstrates the point that adjusting betas and adjusting the slope of the risk/return relationship through the ECAPM are two distinct adjustments and are not duplicative as alleged by Mr. Megginson, Mr. Coppola, and Mr. Walters. As shown in Figure 12, when beta is adjusted to recognize that betas revert to the market mean of 1.0 over time and used in the CAPM, the resulting adjustment is shown by the red arrow in the lower right-hand corner. Separately, when the ECAPM is employed to recognize that the risk/return relationship is flatter than predicted by the CAPM, the resulting adjustment is shown by the green arrow in the lower right-hand corner. To the extent that a company with a beta greater than 1.0 is being evaluated, the same process of two separate adjustments would apply, albeit in the opposite direction from what is shown in Figure 12 and would result in a decrease in the cost of equity otherwise predicted by the CAPM.

[151] Dr. Roger A. Morin, *New Regulatory Finance*, Public Utilities Reports, Inc., 2006, at 191 (emphasis added).

**Figure 12: Risk/Return Relationship between CAPM and ECAPM**




**Q. Are you aware of academic studies that have used adjusted betas to estimate the ECAPM?**

A. Yes. For example, Litzenberger, Ramaswamy, Sosin (1980) studied the ability of the CAPM to estimate the returns for utilities, and found that the CAPM tends to understate the return for stocks such as utilities, which have a beta less than 1.0.[152] To develop the analysis, Litzenberger, *et al*. utilized both adjusted and raw betas, and in both cases, the CAPM understated the return for utilities with betas less than 1.0. In addition, Chrétien and Coggins (2011) studied the CAPM and its ability to estimate the risk premium for the utility industry in particular subgroups of utilities for a data set that included market data through the end of 2006.[153] Chrétien and Coggins considered the CAPM, the Fama-French

[152] Robert Litzenberger, *et al*., "On the CAPM Approach to the Estimation of A Public Utility's Cost of Equity Capital," *The Journal of Finance*, Vol. 35, No. 2, 1980, at 369-383.

[153] Stéphane Chrétien and Frank Coggins, "Cost Of Equity For Energy Utilities: Beyond The CAPM," *Energy Studies Review*, Vol. 18, No. 2, 2011.

three-factor model, and a model similar to the ECAPM. The study shows that the ECAPM significantly outperformed the traditional CAPM at predicting the observed risk premium for the various utility subgroups.

Additionally, Dr. Morin directly addresses the issue in his 2021 text *Modern Regulatory Finance* as follows:

> Because of this adjustment, some critics of the ECAPM argue that the use of Value Line adjusted betas in the traditional CAPM amounts to using an ECAPM. This is incorrect. The use of adjusted betas in a CAPM analysis is not equivalent to the ECAPM. Betas are adjusted because of the regression tendency of betas to converge towards 1.0 over time. We have seen that numerous empirical studies have determined that the SML [Security Market Line] described by the CAPM formula at *any given moment* in time is not as steeply sloped as the predicted SML. The slope of the SML should not be confused with Beta. On the point, Eugene F. Brigham, finance professor and the author of many financial textbooks states:
>
> > The Slope of the SML (5% in Figure 6-16) reflects the degree of risk aversion in the economy. The greater the average investor's aversion to risk, then (a) the steeper the slope of the line, (b) the greater the risk premium for all stocks, and (c) the higher required rate of return on all stocks. Students sometimes confuse beta with the slope of the SML. This is a mistake.
>
> The use of an adjusted beta by Value Line is correcting for a different problem than the ECAPM. The adjusted beta captures the fact that betas regress towards one over time. The ECAPM corrects for the fact that the CAPM under-predicts observed returns when beta is less than one and over-predicts observed returns when beta is greater than one.[154]

[154] Roger A. Morin, *New Regulatory Finance*, Public Utilities Reports, Inc., 2006, at 223-224 (emphasis added).

**Q. Do you agree with Mr. Megginson and Mr. Coppola that your ECAPM is flawed because of the use of a long-term risk-free rate as opposed to a short-term risk-free rate?**

A. No. While Mr. Megginson does not explain his disagreement on this issue, Mr. Coppola contends that Dr. Morin concluded in *New Regulatory Finance* that the use of the ECAPM was not required if long-term interest rates were used as the risk-free rate as opposed to short-term interest rates.[155] However, Mr. Coppola misquotes Dr. Morin and, thus, misrepresents Dr. Morin's conclusion regarding the ECAPM. Specifically, Dr. Morin states the following:

> ***An alpha range of 1%-2% is somewhat lower than estimated empirically. The use of a lower value for alpha leads to a lower estimate of the cost of capital for low-beta stocks such as regulated utilities. That is because the use of a long-term risk-free rate rather than a short-term risk-free rate already incorporates some of the desired effect of using the ECAPM. That is, the long-term risk-free rate version of the CAPM has a higher intercept and a flatter slope than the short-term risk-free rate version which has been tested. Thus, it is reasonable to apply a conservative alpha adjustment***. Moreover, the lowering of the tax burden on capital gains and dividend income enacted in 2002 may have decreased the required return for taxable investors, steepening the slope of the ECAPM risk-return trade-off and bring it closer to the CAPM predicted returns.[156]

Thus, Dr. Morin developed the ECAPM based on a conservative estimate of alpha (i.e. 1% to 2%) relative to the range of alphas estimated empirically to account for the effect of using a long-term risk-free rate as opposed to a short-term risk-free rate. Figure 13 provides the list of studies summarized by Dr. Morin. As shown, six of the eight studies

[155] Coppola Direct, at 142-143.

[156] Dr. Roger A. Morin, *New Regulatory Finance*, Public Utilities Reports, Inc., 2006, at 191; emphasis added.

estimated positive values of the constant term, and among the six studies that estimate only positive values of the constant term, the range of the constant term was 1.63% to 13.56%. It is evident that Dr. Morin's use of an alpha in the range of 1% to 2% to develop the 0.25 and 0.75 factors included in the ECAPM is conservative. The ECAPM was developed to be used with a long-term risk-free rate, and thus the use of a long-term risk-free rate is not a substitute for the ECAPM as suggested by Mr. Megginson and Mr. Coppola.

**Figure 13: Empirical Evidence on the Alpha Factor (Constant Term)[157]**

| Author | Range of Alpha |
|---|---|
| Fischer (1993) | -3.6% to 3.6% |
| Fischer, Jensen and Scholes (1972) | -9.61% to 12.24% |
| Fama and McBeth (1972) | 4.08% to 9.36% |
| Fama and French (1992) | 10.08% to 13.56% |
| Litzenberger and Ramaswamy (1979) | 5.32% to 8.17% |
| Litzenberger, Ramaswamy and Sosin (1980) | 1.63% to 5.04% |
| Pettengill, Sundaram and Mathur (1995) | 4.6% |
| Morin (1989) | 2.0% |

[157] Roger A. Morin, *Modern Regulatory Finance*, Public Utilities Reports, Inc., 2021, at 222.

**Q. While Mr. Megginson and Mr. Bandyk state that the Commission has not previously considered the merits of the ECAPM,[158] and Mr. Coppola states that the ECAPM is not widely accepted by state regulatory commissions,[159] are you aware of state regulatory commissions that have accepted the use of the ECAPM in the manner as you have conducted?**

A. Yes. While Mr. Coppola references a Company data response from a proceeding filed in 2017 as support for his position,[160] there are various regulatory commissions that have supported the use of the ECAPM in establishing an authorized ROE and have done so when adjusted betas are used in the ECAPM analysis. For example, the New York Public Service Commission ("NYPSC"), the Montana Public Service Commission ("Montana PSC"), and North Carolina Utilities Commission ("NCUC") have accepted the ECAPM analysis with the use of adjusted beta coefficients in establishing the authorized ROE for regulated utilities. Specifically, the NYPSC gives equal weight to the CAPM and ECAPM (which it refers to as the "Zero Beta" CAPM) results,[161] the Montana PSC has expressed preference for the ECAPM analysis,[162] and the NCUC has recently found that both the adjustment to beta in the CAPM and the adjustment in the ECAPM were needed because they correct for different things.[163] Exhibit A-128 (AEB-3).

158 Megginson Direct, at 33; Bandyk Direct, at 21.
159 Coppola Direct, at 143-144.
160 *Id*., at 143.
161 New York Public Service Commission Case No. 20-G-0101, Order, May 19, 2021, at 44-46.
162 Montana Public Service Commission, Docket No. D2017.9.80, Order No. 7575c, September 26, 2018, at 40.
163 North Carolina Utilities Commission, Docket No. E-2, SUB 1300, Order Accepting Stipulations, Granting Partial Rate Increase, and Requiring Public Notice, August 18, 2023, at 162-63.

## IX. BOND YIELD RISK PREMIUM ANALYSIS

**Q. Do any of the witnesses conduct a Risk Premium analysis?**

A. Yes. Mr. Megginson, Mr. Coppola, and Mr. Walters have each conducted a Risk Premium analysis. Specifically:

- Mr. Megginson conducts two forms of a Risk Premium analysis: one reflecting the historical equity risk premium of gas utility stock returns less utility bond yields over the period 1954 to 2024 plus a projected utility bond yield on A-rated rated utility bonds ("Utility Bond Approach"); and another reflecting the historical equity risk premium of gas utility stock returns less 30-year Treasury bond yields over the period 1954 to 2024 plus a projected 30-year Treasury bond yield ("Treasury Bond Approach"). The cost of equity resulting from Mr. Megginson's Utility Bond Approach is 9.56%, respectively, while the cost of equity from his Treasury Bond Approach is 9.46%.[164]

- Mr. Coppola's Risk Premium analysis is similar to Mr. Megginson's Utility Bond Approach, as Mr. Coppola's analysis reflects the historical equity risk premium of gas utility stock returns less A-rated utility bond yields over the period 1954 to 2023 plus a projected average yield on A-rated/BBB-rated utility bonds. Mr. Coppola calculates his projected utility yield by averaging the 2024 spreads between A-rated utility bonds and the 30-year Treasury, and BBB-rated utility bonds and the 30-year Treasury. He adds this average spread to the 4.00% 30-year Treasury rate from his CAPM. Mr. Coppola's risk premium model produces a cost of equity of 9.20%.[165]

- Similarly, Mr. Walters develops five cost of equity estimates based on two forms of a Risk Premium analysis: one reflecting the risk premium relative to yields on 30-year Treasury by subtracting the average 30-year Treasury yield from the average authorized Gas ROE over the period 1986-2024 plus a projected 30-year Treasury yield ("Treasury Bond Approach") to produce a 10.23% cost of equity; and four based on the utility equity risk premium relative to yields on both the Moody's A-rated and Baa-rated utility bonds both using

[164] Megginson Direct, at 33-34 and Exhibit S-4, Schedule D-5.
[165] Coppola Direct, at 137 and Exhibit AG-45.

3-month average yield data and 6-month yield data ("Utility Bond Approach") to produce a cost of capital estimate ranging from 9.73% to 9.98%.[166]

**Q. Do you agree with Mr. Megginson's, Mr. Coppola's, and Mr. Walters' Risk Premium analyses?**

A. No. The key issue, as previously discussed, is that their analyses apply a historical risk premium to a projected interest rate which fails to consider the inverse relationship between interest rates and the market risk premium. Specifically, the witnesses' risk premium methods add a current or projected yield (i.e. a utility bond yield or a Treasury bond yield) that differs from the historical average rate used to estimate the risk premium. There is an interest rate mismatch in their calculation. Consequently, their Bond Yield to Risk Premium ("BYRP") results do not reflect what it would be if the historical rate had been used consistently, resulting in ROEs that fail to appropriately account for the dynamic, inverse relationship between risk premiums and interest rates. Because historical bond yields are higher than the bond yields utilized by the witnesses in their analyses, and given inverse relationship between risk premiums and interest rates, their analyses, which utilize a historical risk premium, understate the cost of equity.

For example, in his Treasury Bond Approach, Mr. Megginson adds a near-term projected Treasury bond yield of 4.25% to his historical average Treasury bond risk premium of 5.21%, resulting in his estimated cost of equity of 9.46%.[167] However, as shown on Mr. Megginson's Exhibit S-4, Schedule D-5, the average 30-year Treasury bond yield over the 1954-2024 period was 5.73%, *or more than 145 basis points higher* than the

[166] Walters Direct, at 43-47.
[167] Megginson Direct, at 34.

near-term projected Treasury bond yield of 4.25% that he relies on to calculate the cost of equity for this version of his Risk Premium analysis.

**Q. Can you show the impact to ROE estimates by mismatching historical and projected interest rates?**

A. Figure 14 shows how the witnesses' mismatching of the historical and projected interest rates leads to understated cost of capital estimates. All witnesses projected interest rates are less than the historical interest rates that were used for their risk premium calculation. When adding the historical interest rate to the risk premium for consistency, estimates for the cost of capital are significantly higher by at least 54 basis points[168] in all cases and on average 115 basis points higher.[169] Please note that I do not endorse this method, but simply demonstrate how the witnesses materially understate the ROE by being inconsistent with their interest rates usage in their risk premium models.

[168] Mr. Walters' adjusted 10.77% less his 10.23% ROE result.

[169] Average spread between ROE using only historical bond yield less ROE as reported from Figure 14.

**Figure 14: Update of Mr. Megginson's, Mr. Coppola's, and Mr. Walters' Risk Premium Analyses[170]**

| | Historical Bond Yield | Current or Projected Bond Yield | Historical Risk Premium as Reported | ROE as Reported | ROE Using Only Historical Bond Yield |
|---|---|---|---|---|---|
| **Mr. Megginson** | | | | | |
| Utility Bond Approach (A-Rated) | 7.14% | 5.76% | 3.80% | 9.56% | 10.94% |
| Treasury Bond Approach | 5.73% | 4.25% | 5.21% | 9.46% | 10.94% |
| **Mr. Coppola Utility Bond Approach** | 7.14% | 5.40% | 3.80% | 9.20% | 10.94% |
| **Mr. Walters** | | | | | |
| Treasury Bond Approach | 5.14% | 4.60% | 5.63% | 10.23% | 10.77% |
| 3-Month Average Yields | | | | | |
| Utility Bond Approach (A-Rated) | 6.50% | 5.51% | 4.27% | 9.78% | 10.77% |
| Utility Bond Approach (Baa-Rated) | 6.70% | 5.71% | 4.27% | 9.98% | 10.97% |
| 6-Month Average Yields | | | | | |
| Utility Bond Approach (A-Rated) | 6.50% | 5.46% | 4.27% | 9.73% | 10.77% |
| Utility Bond Approach (Baa-Rated) | 6.70% | 5.67% | 4.27% | 9.94% | 10.97% |

**Q. Do you have any additional concerns with the Risk Premium analysis conducted by Mr. Coppola?**

A. Yes. As discussed previously in my response to Mr. Coppola's CAPM analysis, he relies on an outdated near-term projected risk-free rate as of October 2024 from the *Blue Chip Financial Forecasts* when more current data is available, particularly when his testimony was filed on April 23, 2025.[171]

[170] Megginson Exhibit S-4, Schedule D-5; Coppola workpapers; Walters Exhibit AB-15, Exhibit AB-16, and Exhibit AB-18. Mr. Walters uses the same risk premium derived from A-rated utility bonds as he does for Baa-rated utility bonds. As a result, the 6.70% historical Baa-rated bond is implied.

[171] Coppola Exhibit AG-44 and Exhibit AG-45.

**Q. What are the positions offered by Mr. Megginson, Mr. Coppola, Mr. Bandyk, and Mr. Walters regarding your Risk Premium analyses?**

A. The following summarizes the reasons offered by each of these witnesses to suggest that my Risk Premium approach should be given little weight or not be relied upon:[172]

- Mr. Megginson and Mr. Coppola claim that my Risk Premium analyses reflect a simplistic inverse relationship between equity risk premiums and interest rates and contend that this relationship can be influenced by factors other than interest rates.[173]

- Mr. Megginson and Mr. Coppola oppose the use of my Risk Premium analysis because they contend that authorized ROEs are not market behavior but rather a reflection of regulator behavior.[174]

- Mr. Coppola objects that interest rates of up to 12.10% in the late 1980s are not comparable to today's environment, and therefore should not be included in a BYRP analysis.[175]

- Mr. Walters believes that my BYRP analysis uses electric utilities and uses overstated equity risk premiums.[176]

- Mr. Bandyk believes that authorized ROEs used as an input in my BYRP have been "excessive." Mr. Bandyk rejects my BYRP and does not perform one himself.[177]

- Mr. Walters believes that my BYRP analysis is predicated on an overstated risk premium.[178]

[172] Megginson Direct, at 35. Walters Direct, at 73. Coppola Direct, at 138. Bandyk Direct, at 24.
[173] Megginson Direct, at 34-35; Coppola Direct, at 138.
[174] *Id*.
[175] Coppola Direct, at 138.
[176] Walters Direct, at 72.
[177] Bandyk Direct, at 24-25.
[178] Walters Direct, at 73.

**Q. Is there any validity to Mr. Megginson's or Mr. Coppola's claims regarding your Risk Premium analyses?**

A. No. While authorized ROEs are not "market data," it is unreasonable to suggest that investors are not aware of authorized ROEs and do not consider them in their assessment of the value of a utility stock. Recent market data demonstrates that unconstructive ROEs have resulted in sharp declines in utility stock prices, as well as commentary from equity analysts and rating agencies. Accordingly, it is appropriate for the Commission to accept and consider the results of my Risk Premium analyses. In addition, while I disagree with his approach, Mr. Walters also relies on a risk premium-based methodology as one of the methodologies he uses to estimate the cost of equity.

**Q. Do you agree with Mr. Megginson that it is more appropriate to use historical authorized ROEs for comparison as opposed to an input in your BYRP analysis?[179]**

A. No. As discussed in my direct testimony, it is important to recognize that both academic literature and market evidence have identified a relationship between the equity risk premium and the level of interest rates (i.e. as interest rates increase, the equity risk premium decreases, and vice versa). Consequently, it is important to develop an analysis that: (1) reflects the inverse relationship between interest rates and the equity risk premium; and (2) relies on recent and expected market conditions. Accordingly, I have developed such an analysis based on a regression of the risk premium as a function of 30-year Treasury bond yields. As discussed, neither Mr. Megginson's nor Mr. Coppola's Risk Premium analyses appropriately account for this inverse relationship, and I have

[179] Megginson Direct at 35.

demonstrated that their use of an historical average market risk premium fails to account for this inverse relationship. Therefore, there is no basis to Mr. Megginson's suggestion that the results of my Risk Premium analysis do not appear to align simply because I do not utilize a historical market risk premium, but rather appropriately apply the regression results of the historical data to the current and projected interest rates.

**Q. Do you agree with Mr. Megginson and Mr. Coppola that your Risk Premium results are invalid because you have not considered other factors in addition to interest rates in your regression analyses?**

A. No. Mr. Megginson and Mr. Coppola fail to recognize the large body of research that supports the inverse relationship between equity risk premia and interest rates and have failed to present any research to support their positions. For example, Berry (1998) came to similar conclusions regarding the inverse relationship between interest rates and the risk premia.[180] Also, as summarized in *New Regulatory Finance*:

> Published studies by Brigham, Shome, and Vinson (1985), Harris (1986), Harris and Marston (1992, 1993), Carleton, Chambers, and Lakonishok (1983), Morin (2005), and McShane (2005), and others demonstrate that, beginning in 1980, risk premiums varied inversely with the level of interest rates—rising when rates fell and declining when interest rates rose. The reason for this relationship is that when interest rates rise, bondholders suffer a capital loss. This is referred to as interest rate risk…. Conversely in low interest rate environments, when bondholders' interest rate fears subside and shareholders' fears of loss of earning power dominate, the risk differential will widen and hence the risk premium will increase.[181]

[180] S. Keith Berry, "Interest Rate Risk and Utility Risk Premia during 1982-93," *Managerial and Decision Economics*, Vol. 19, No. 2, March, 1998.

[181] Dr. Roger A. Morin, *New Regulatory Finance*, Public Utilities Reports, Inc., 2006, at 128.

In his more recent textbook, *Modern Regulatory Finance*, Dr. Morin outlines the issues and academic research and concludes the following with respect to the relationship between interest rates and the equity risk premium:

> This is particularly true in a high inflation environment. Interest rates rise as a result of accelerating inflation, and the interest rate risk of bonds intensifies more than the earnings of common stocks, which are partially hedged from the ravages of inflation. This phenomenon has been termed as a "lock-in" premium. Conversely, in low interest rate environments, when bondholders' interest rate fears subside and shareholders' fears of loss of earnings power dominate, the risk differential will widen and hence the risk premium will increase.
>
> Published empirical studies demonstrate that risk premiums vary inversely with the level of interest rates, rising when rates fell and declining when interest rates rose. Studies by Brigham, Shone, and Vinson (1985), Harris (1986), Harris and Marston (1992, 1993), Carleton, Chambers, and Lakonishok (1983), and Morin 2020), and others ***demonstrate that, beginning in 1980, risk premiums varied inversely with the level of interest rates – rising when rates fell and declining when rates rose***.[182]

These studies demonstrate that my Risk Premium analysis is consistent with academic and scholarly research. Mr. Megginson and Mr. Coppola do not present any academic studies that refute the bases and methodology that I have used in my Risk Premium analyses.

[182] Roger A. Morin, *Modern Regulatory Finance*, Public Utilities Reports, Inc., 2021, at 146; graphic referenced in cite and shown in text has been omitted.

**Q. Does the regression analysis that you have conducted for your Risk Premium analysis demonstrate a strong inverse relationship between interest rates and the equity risk premium?**

A. Yes. As shown both in my direct testimony on Exhibit A-14, Schedule D-5, page 22, and as updated herein on Exhibit A-127 (AEB-2), page 21, the regression equation for my Risk Premium analysis has an $R^2$ of approximately 0.86, which means that 86.00% of the variation in historical implied utility equity risk premia can be explained by changes in interest rates. The regression indicates that there indeed exists a strong negative correlation between utility equity risk premia and interest rates, and that the regression equation is an effective tool for predicting authorized ROEs at specified interest rate levels, whether current or projected interest rates. Mr. Megginson and Mr. Coppola fail to address this strong relationship demonstrated by the data in my Risk Premium analysis, which invalidates the critiques offered by Mr. Megginson that there are "numerous" factors that are unaccounted for in my analyses and by Mr. Coppola that regulators establish "ROEs based on many factors" that are not in lock-step with interest rates.[183]

**Q. Do you agree with Mr. Megginson and Mr. Coppola that your Risk Premium methodology does not measure investor behavior and is therefore invalid?**

A. No. As noted previously, it is unquestionable that both credit rating agencies and investors consider the authorized ROE data in their determination of the valuation of utility stocks. As I discussed both earlier in this rebuttal testimony and in my direct testimony, both credit rating agencies and investors have responded negatively to authorized ROEs deemed to be

[183] Megginson Direct, at 35; Coppola Direct, at 138.

too low.[184] Therefore, the relationship between recently authorized ROEs and the prevailing interest rates at the time that the ROE was authorized is reasonable to consider when setting the ROE in the context of a rate proceeding.

Moreover, it is important to recognize the inconsistency in both Mr. Megginson's and Mr. Coppola's position regarding the reliance of authorized ROEs in the Risk Premium analysis. Each of these witnesses suggest that my Risk Premium approach cannot be relied upon because the authorized ROEs reflect regulatory commission behavior and not investor behavior. However, despite that claim, both Mr. Megginson and Mr. Coppola evaluate the same authorized ROE and 30-year Treasury bond yield data that I use in my Risk Premium analyses in their own testimony as support for their recommended ROEs for the Company in this proceeding.[185] Therefore, Mr. Megginson and Mr. Coppola are inconsistent in their positions on the use of this information, seeking only to rely on it in establishing their own ROE recommendations while disregarding the historical relationship developed in my Risk Premium approach.

**Q. Please respond to Mr. Coppola's concern that interest rates of the 1980s are not comparable to today's interest rates.**

A. The high interest rates of the 1980s correspond with high authorized natural gas ROEs. Therefore, as seen in Exhibit A-14, Schedule D-5, page 23, of my direct testimony, the individual risk premium data points from the 1980s are comparable, if not lower than risk premiums in recent quarters.

[184] Bulkley Direct, at 39-47.

[185] Megginson Direct, at 34-35; Coppola Direct, at 146, Exhibit AG-45, and Exhibit AG-48.

Mr. Coppola undermines his own methods with his critique by relying on the very type of data he dismisses. While he takes issue with my use of data from the 1980s in the BYRP, he has no problem using historical equity and bond data, not only from the same period, but going as far back as 1952 in his Risk Premium approach.[186]

**Q. Please respond to Mr. Walters' claim that your risk premium is overstated.**

A. As a threshold matter, I use natural gas authorized ROEs in my BYRP analysis, not electric authorized ROEs as Mr. Walters states.[187]

Mr. Walters' claim that my risk premium is overstated is based on his own long-term historical average risk premium. However, as discussed earlier, his long-term average risk premium does not reflect current market conditions and bond yields. As shown on Mr. Walters' Exhibit AB-15, Mr. Walters' long-term historical average risk premium over 30-year Treasury bond yields is 5.63%, but his long-term historical average 30-year Treasury bond yield is 5.14%. This is despite Mr. Walters acknowledging that current 30-year Treasury bond yields are lower at approximately 4.60%.[188] Therefore, based on the inverse relationship between interest rates and the equity risk premium, an interest rate that is lower than the historical average means that the equity risk premium should be higher than his historical average of 5.63% – which is the case for my analysis. Therefore, Mr. Walters's criticism of my BYRP analyses is unfounded.

[186] Coppola Direct, at 137.
[187] Walters Direct, at 72.
[188] Walters Direct, at 46.

**Q. What is Mr. Bandyk's position regarding your Risk Premium analyses?**

A. Mr. Bandyk states that the results of my Risk Premium analyses should be disregarded because it relies on the ROEs authorized by other commissions, which he argues is not objective data but rather reflects the fact that regulatory commissions have historically and consistently authorized excessive ROEs for utilities.[189]

**Q. Is there any merit to Mr. Bandyk's position regarding your Risk Premium analyses?**

A. No. As I discussed previously, there is no merit to Mr. Bandyk's claim that regulatory commissions have consistently authorized "excessive" ROEs.

**Q. Do any witnesses use regression analysis?**

A. No.

**Q. What are some benefits of using regression analysis as opposed to reviewing simple averages?**

A. The benefit of conducting a regression analysis is that the resulting predictive equation can be used to estimate a *forward-looking* equity risk premium corresponding to *any* interest rate one wishes to specify. By specifying the interest rate projected for the time period that the Company's rates from this proceeding will be in effect, one can estimate an equity risk premium (and thus an ROE) for the *forward-looking* time period that corresponds with the rates that are set in this proceeding.

While using average authorized ROEs can be useful starting point for analysis, regression analysis formalizes comparing previous ROEs in a systematic way that allows for forward-looking estimating. Regression analysis is a common forecasting tool.

[189] Bandyk Direct, at 24-25.

## X. SUMMARY OF THE ADJUSTED RESULTS

**Q. Have you considered how the ROE recommendations of Mr. Megginson, Mr. Coppola, Mr. Bandyk, and Mr. Walters would change if their cost of equity analyses were corrected for the issues you have identified with each of their analyses?**

A. Yes, I evaluate how each of these witnesses' ROE recommendations would change once their analyses are updated and corrected.

**Q. How do the results of Mr. Megginson's cost of equity analyses change if the issues that you have identified are addressed with each of his analyses?**

A. Figure 15 presents the results of Mr. Megginson's cost of equity analyses based on the updates and corrections to those analyses that I have discussed. As shown, when the results of Mr. Megginson's cost of equity analyses based on the updates and corrections to those analyses that I have discussed are considered, the average cost of equity resulting from his analyses is 10.68%, which is greater than the Company's requested ROE of 10.25% in this proceeding.

**Figure 15: Results of Mr. Megginson's as Filed and Adjusted Cost of Equity Analyses**

| | | Mr. Megginson As Filed | Mr. Megginson As Adjusted |
|---|---|---|---|
| Constant Growth DCF | [1] | 9.40% | 10.58% |
| CAPM | | | |
| Historical MRP | | 10.63% | 11.53% |
| Projected Market Risk Premium | | | |
| Proj. Retrun on S&P 500 Less Risk-free Rate | | n/a | 11.41% |
| Damodaran (4.35%) | | 8.25% | n/a |
| Damodaran (6.18%) | | 9.93% | n/a |
| Average | [2] | 9.60% | 11.47% |
| Risk Premium | | | |
| Utility Bond Risk Premium (A-rated) | | 9.56% | 10.94% |
| Treasury Bond Risk Premium | | 9.46% | 10.94% |
| Average | [3] | 9.51% | 10.94% |
| Authorized ROEs | | | |
| 2024 Avg. Auth'd Gas ROE | [4] | 9.72% | 9.72% |
| Average of [1], [2], [3], [4] | | **9.56%** | **10.68%** |
| Recommended ROE | | 9.75% | |
| Company's Proposed ROE | | | 10.25% |

**Q. How do the results of Mr. Coppola's cost of equity analyses change if the issues that you have identified are addressed with each of his analyses?**

A. Figure 16 presents the results of Mr. Coppola's cost of equity analyses based on the updates and corrections to his analyses that I have discussed. As shown, Mr. Coppola applies a 50% weighting to the result of his constant growth DCF and a 25% weighting each to the results of his CAPM and Risk Premium analyses. As shown in Figure 16, applying these same weightings to the updates and corrections to Mr. Coppola's analyses produces a cost

of equity of 10.51%, which supports the Company's requested ROE of 10.25% in this proceeding.

**Figure 16: Results of Mr. Coppola's as Filed and Adjusted Cost of Equity Analyses**

| | Model Weighting | As Filed | As Adjusted |
|---|---|---|---|
| Constant Growth DCF | 50.00% | 9.11% | 9.79% |
| CAPM | 25.00% | 10.66% | 11.50% |
| Risk Premium | 25.00% | 9.20% | 10.94% |
| **Wgtd. Avg. Cost of Equity** | | **9.52%** | **10.51%** |
| Recommended ROE | | 9.75% | |
| Company's Proposed ROE | | | 10.25% |

**Q. How do the results of Mr. Walters's cost of equity analyses change if the issues that you have identified are addressed with each of his analyses?**

A. Figure 17 summarizes the results of Mr. Walters' cost of equity models based on the adjustments to his analyses that I have discussed. Based on these changes, the average results of each of Mr. Walters' three analyses range from 10.38% to 11.05%, with a midpoint of 10.72%, which supports the Company's proposed ROE of 10.25%, and is significantly greater than Mr. Walters' recommended ROE of 9.45%.

**Figure 17: Results of Mr. Walters's As-Filed and Adjusted Cost of Equity Analyses[190]**

| | Mr. Walters As Filed | | Mr. Walters As Adjusted | |
|---|---|---|---|---|
| | **Mean** | **Median** | **Mean** | **Median** |
| DCF | | | | |
| Constant Growth (analyst growth rates) | 13.54% | 10.74% | n/a | 11.05% |
| Constant Growth (sustainable growth rates) | 8.70% | 8.38% | n/a | n/a |
| Multi-Stage | 9.26% | 8.47% | n/a | n/a |
| **Average** | **9.85%** | | **11.05%** | |
| Risk Premium | | | | |
| Near-Term Projected Treasury Bond Yield | 10.23% | | 10.77% | |
| 3-Month Avg. A-rated Utility Bond Yield | 9.78% | | 10.77% | |
| 3-Month Avg. Baa-rated Utility Bond Yield | 9.98% | | 10.97% | |
| 6-Month Avg. A-rated Utility Bond Yield | 9.73% | | 10.77% | |
| 6-Month Avg. Baa-rated Utility Bond Yield | 9.94% | | 10.97% | |
| **Average** | **9.93%** | | **10.85%** | |
| CAPM | | | | |
| *Kroll* Normalized Method: | 8.66% | | n/a | |
| Risk Premium Method: | 10.11% | | 10.11% | |
| FERC DCF Method: | 10.65% | | 10.65% | |
| **Average** | **9.81%** | | **10.38%** | |
| **Midpoint** | **9.83%** | | **10.72%** | |
| Recommended ROE | 9.45% | | | |
| Company's Proposed ROE | | | 10.25% | |

**Q. Lastly, how do the results of Mr. Bandyk's cost of equity analyses change if the issues that you have identified are addressed with each of his analyses?**

A. Figure 18 presents the results of Mr. Bandyk's cost of equity analyses based on the updates and corrections to his analyses that I have discussed. As shown, Mr. Bandyk calculates his

[190] The mean constant growth DCF result using projected EPS growth rates was excluded due to a projected EPS growth rate for California Water Service Group of approximately 42% from *Zacks*, S&P and I/B/E/S, which has a significant effect on the average. It is more appropriate to rely on the median which is not affected to a large degree by the presence of outliers.

recommended ROE by taking the average of the results of his two cost of equity analyses, and then average that result with the Company's currently authorized ROE. I disagree with this approach for determining the ROE in this proceeding given that the existing authorized ROE is not representative of the current or projected capital market conditions during the period in which the rates established in this proceeding will be in effect. Therefore, a more appropriate ROE recommendation for the Company based on Mr. Bandyk's corrected cost of equity analyses would be the average of the results of his DCF and CAPM analyses, which is 10.48% and is greater than the Company's requested ROE of 10.25% in this proceeding. Nonetheless, even if the same approach that Mr. Bandyk applies for determining his recommended ROE is applied, the recommended ROE is still 10.19%, or substantially higher than the 9.24% that he reflects in his testimony.

**Figure 18: Results of Mr. Bandyk's As-Filed and Adjusted Cost of Equity Analyses**

| | As Filed | As Adjusted |
|---|---|---|
| DCF | 9.22% | 10.99% |
| CAPM | 7.95% | 9.96% |
| Average | 8.59% | 10.48% |
| Consumers Existing ROE | 9.90% | 9.90% |
| **Recommended ROE** | **9.24%** | **10.19%** |

## XI. BUSINESS RISK

**Q. What are Mr. Megginson's, Mr. Coppola's, Mr. Bandyk's, and Mr. Walters' positions regarding the business and financial risks of the Company relative to the ROE that should be authorized for the Company in this proceeding?**

A. The witnesses have the following positions:

- Mr. Megginson testifies that: Consumers Energy experiences enhanced infrastructure replacement and decoupling, has experienced several years with positive net income growth,[191] and believes that the Commission's prior approval of the Company's main replacement program, as well as other programs and surcharge mechanisms to pay for those programs, "all but ensure recovery and reduces the Company's overall business and financial risk,"[192] and that Consumers Energy's filing every 12-months "borders on a 100% risk-free investment."[193]

- Mr. Coppola claims that his proxy group is riskier than Consumers Energy due to other non-regulated business operations and higher financial leverage.[194]

- Mr. Bandyk dismisses the use of commission rankings as a measure of regulatory risk,[195] and believes that the Company does not possess additional business risk as a result of large capital expenditures and having fewer mechanisms relative to my proxy group.[196]

- Mr. Walters cites an S&P stable outlook and a Barclays analyst who believes that Consumers Energy's parent CMS Energy has financially performed strongly, as evidence that the Company is financially healthy and a lower ROE is warranted.[197]

- None of the witnesses address flotation costs.

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191 Megginson Direct, at 6-10.
192 *Id*., at 37
193 *Id*.
194 Coppola Direct, at 145.
195 Bandyk Direct, at 9.
196 *Id.*, at 27-32.
197 Walters Direct, at 28.

**Q. Is Mr. Megginson correct about the mechanisms that Consumers Energy currently has available to facilitate timely recovery of costs?**

A. Not entirely. As discussed in the testimony of Mr. Bleckman, Consumers Energy does not currently have a decoupling mechanism and currently does not have a surcharge for an Enhanced Infrastructure Replacement Program. Further, while Staff references the Company's Gas Cost Recovery Mechanism and Energy Waste Reduction programs, neither of these programs provides for the recovery of investments made to improve or replace the Company's infrastructure.

**Q. Has Mr. Megginson conducted any analysis to support his position that Consumers Energy has less risk as a result of rate mechanisms?**

A. No. As noted in the testimony of Mr. Bleckman, the mechanisms that Mr. Megginson references are not implemented by Consumers Energy, and therefore it is not possible for such mechanisms to be risk reducing factors. Further, even if Consumers Energy did have certain mechanisms, in order to determine whether or not the risk mitigation should be considered in setting the ROE, it is necessary to review what types of mechanisms have been implemented by the proxy group companies, and therefore are reflected in the market data that is used to estimate the ROE. Mr. Megginson has not done that analysis, nor could he, since the mechanisms that he references are not implemented by Consumers Energy, or the mechanisms do not recover infrastructure improvements. As discussed in my direct testimony, I evaluate Consumers Energy's business and regulatory risk relative to the operating utilities of the proxy group and, based on that analysis, demonstrate that Consumers Energy has moderately greater regulatory risk as compared to the operating

subsidiaries of the proxy group companies given the more-timely cost recovery of the proxy group companies.

**Q. Please respond to Mr. Megginson's analysis of Consumers steady earnings.**

A. Mr. Megginson's analysis is incomplete and inconclusive. Mr. Megginson reviews the Company's annual change in net income in complete isolation, without considering the changes in investment over time or the changes in rate base.[198] To the extent that the Company has invested in the system over the period from 2010 through 2024, its net income should increase. However, the analysis does nothing to demonstrate that the increases in net income are sufficient to satisfy the investor-required return on that investment, nor does it conclude anything meaningful about the Company's financial integrity. Accordingly, in its current form, this analysis cannot be used to conclude anything meaningful about the Company's earnings or its financial integrity and should be disregarded.

**Q. Please respond to Mr. Megginson's claim that the frequency of Consumers Energy's rate filings "borders on a risk-free investment for the Company."[199]**

A. No, filing a rate case is not akin to a risk-free investment. If Mr. Megginson's claim was correct, investors would flood Consumers Energy with capital and bid up its bond prices. The Company's bond yields would converge to risk-free government Treasury yields. Mr. Megginson's claim ignores principles of finance including the risk-reward tradeoff, opportunity cost, and regulatory risk, and he has provided no support for his claim.

[198] Megginson Direct, at 9.
[199] *Id*., at 37.

**Q. Has Mr. Coppola performed an analysis that his proxy group is riskier than Consumers Energy?**

A. No. Mr. Coppola simply claims this because some proxy group companies have non-regulated business segments.[200] He does not refer to specific companies nor does he attempt to measure any impact of non-regulated activities of his proxy group. On the other hand, my proxy screening criteria involves quantifying companies' non-regulated operating incomes. Companies in my proxy group who derive some operating income from non-regulated activities have similar cost of equity estimates to companies that derive 100% operating income from regulated operations. Furthermore, when discussing regulatory and business risk in my direct testimony, I only consider regulated business operations of my proxy group for comparability.[201] Therefore, Mr. Coppola's claim that his proxy group, or mine for that matter, is riskier than the Company is baseless.

**Q. Is Mr. Bandyk's rejection of considering regulatory environment rankings reasonable?**

A. No. Mr. Bandyk believes that the rankings "appear to be judgments for how generous utility commissions tend to be with the ROEs they tend to grant utilities."[202] This is incorrect. A recent publication that summarizes commission rankings from S&P Global Ratings states that:

> We assess all North America's regulatory jurisdictions as credit supportive or better, reflecting the industry's generally stable and predictable cash flows (see chart 16). Over the past decade much of the industry has implemented regulatory mechanisms such as decoupling, interim rates,

[200] Coppola Direct, at 145.
[201] Bulkley Direct, at 33-47.
[202] Bandyk Direct, at 9.

> capital trackers, formula rate plans, forward test years, muti-year rate case filings, and regulatory riders to significantly improve cash flow stability while minimizing regulatory lag.[203]

The statement emphasizes cash flow, not "how generous" commissions are towards awarding ROEs. The rankings are simply an additional input for the Commission to consider in their decision.

**Q. Do you agree with Mr. Bandyk's assessment of the risk factors that you evaluated?**

A. No. Mr. Bandyk rejects the notion that the Company has additional risk that should be considered. Rather, he believes that relative to the proxy group, the Company's lower capital expenditure and the absence of comparable rate mechanisms do not support my position that the Company faces more risk.[204]

To be clear, the capital investment analysis in my direct testimony concludes that Consumers Energy faces slightly higher risk than the proxy group because it has a significant capital spending plan and does not have a mechanism to recover those investments. In comparison, the majority of the proxy group companies have some form of capital tracking mechanism. Therefore, Consumers Energy has slightly higher risk than the proxy group on this basis.

Mr. Bandyk's alternative analysis confirms my conclusion that the Company has fewer mechanisms relative to the proxy company. Mr. Bandyk compares rate mechanisms between Consumers Energy and my proxy group using an alternative weighting. His alternative method equally weights proxy group companies instead of my equal weighting

[203] S&P Global Ratings. "North America Regulated Utilities: Capex and climate change pressures credit quality." Industry Credit Outlook 2025. January 14, 2025.

[204] Bandyk Direct, at 26-32.

to each subsidiary such that each of my six proxy group companies receive a 1/6th (i.e. an approximately 16.67%) weight. Although I disagree with Mr. Bandyk's method of limiting subsidiary weights by parent company in the proxy group, his results still show that most companies in my proxy group have more capital investment recovery mechanisms than Consumers Energy. [205]

**Q. Do you agree with Mr. Megginson that a utility should not recover flotation costs if the equity is issued at the parent company level?**

A. No. Mr. Megginson's position with respect to the recovery of flotation costs related to equity issuances is inconsistent with his position on the recovery of the costs associated with debt issuances.[206] Mr. Megginson acknowledges that the cost of debt issuances should be and are recovered by utilities; however, he suggests that the cost of issuing equity should be born at the parent company level because that is where equity is issued. I disagree entirely. The cost of equity capital that is raised on behalf of the operating company results in a permanent reduction in the overall capital that is received through an issuance and is properly reflected in the cost of equity for the operating company that is in receipt of the equity capital.

**Q. Does this conclude your rebuttal testimony?**

A. Yes.

[205] Bandyk Direct, at 28-29.
[206] Megginson Direct, at 25.

MR. RUSZKIEWICZ: The next witness is Jessica R. Byrom. And based on the stipulation of the parties, the Company moves to bind in Ms. Byrom's testimony. Her direct testimony was confidentially filed, and consists of a cover page and 20 pages of prefiled testimony. Her rebuttal testimony consists of a cover page and 31 pages of prefiled testimony.

The Company moves to admit Ms. Byrom's exhibits, which consist of Exhibit A-12 Schedule B-5.3, A-37, A-38, A-129. And I believe that's it for Ms. Byrom's.

JUDGE VARCHETTI: All right. Are there any objections to the admission of Ms. Byrom's confidential direct testimony, her rebuttal testimony, or any of the associated exhibits?

Hearing none, then, the testimony is bound into the record and the exhibits are admitted.

MR. RUSZKIEWICZ: Thank you, Your Honor.

(Direct Redacted Testimony bound in in Confidential Record)

(Rebuttal Testimony bound in)

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

| | | |
|---|---|---|
| In the matter of the application of<br>**CONSUMERS ENERGY COMPANY**<br>for authority to increase its rates for the<br>distribution of natural gas and for other relief. | )<br>)<br>)<br>)<br>) | Case No. U-21806 |

**REDACTED**

# DIRECT TESTIMONY

**OF**

**JESSICA R. BYROM**

**ON BEHALF OF**

**CONSUMERS ENERGY COMPANY**

December 2024

**Q. Please state your name and business address.**

A. My name is Jessica R. Byrom, and my business address is One Energy Plaza, Jackson, Michigan 49201.

**Q. By whom are you employed and what is your present position?**

A. I am employed by Consumers Energy Company ("Consumers Energy" or the "Company") as Director of Customer Strategy.

**Q. Please review your educational background.**

A. I graduated from Michigan State University in 2008 with a Bachelor of Arts in International Relations and in 2015 with a Master of Business Administration.

**Q. Please review your business experience.**

A. In 2009, I began full-time employment with Michigan State University, working primarily in a human resources role during my tenure with the university. My role centered around process optimization and management of our hiring, firing, and compliance investigation processes for the department's 4,000 part-time and nearly 500 full-time employees. In 2017, I began my career at Consumers Energy as a member of the Customer Operations Strategy team. I was promoted to manager and eventual director of this team in March 2018. During my time with that team, I had the responsibility of working with the Company's business partners within the Customer Operations and Customer Experience teams related to goal creation, data organization, process optimization, testimony creation for rate cases, and the implementation of lean operating system framework. In September 2021, I took on the role of Director of Residential Demand Side Management, leading the team that owns and manages the products within the Residential sector for Energy Waste Reduction ("EWR") and Demand Response ("DR"). In June 2024 I took on the role of Director of Customer Strategy.

**Q. What are your responsibilities as the Director of Customer Strategy?**

A. In this position, I am responsible for implementation of the Company's lean operating system within the Customer organization, partnering with business units to improve Customer-related processes, and supporting the Customer business functions with executive communications.

**Q. Have you previously testified before the Michigan Public Service Commission ("MPSC" or the "Commission")?**

A. Yes, I filed testimony on behalf of the Company in the following proceedings before the Commission:

| | |
|---|---|
| Case No. U-21233 | 2021 DR Reconciliation; |
| Case No. U-21205 | 2021 EWR Reconciliation; |
| Case No. U-21321 | 2024-2025 EWR Plan; |
| Case No. U-21410 | 2022 DR Reconciliation; and |
| Case No. U-21647 | 2023 DR Reconciliation. |

**Q. What is the purpose of your direct testimony in this proceeding?**

A. The purpose of my direct testimony is to describe the Customer Experience and Operations ("CX&O") organization and how the work performed within this organization benefits the Company's residential and business gas customers. As part of my direct testimony, I will address the operating and maintenance ("O&M") expenses and capital investments associated with executing this work in the test year ending October 2026.

**Q. Are you sponsoring any exhibits?**

A. Yes, I am sponsoring the following exhibits:

| | | |
|---|---|---|
| Exhibit A-12 (JRB-1) | Schedule B-5.3 | Actual and Projected Capital Expenditures - Customer Experience & Operations; |

| | |
|---|---|
| Exhibit A-37 (JRB-2) | Summary of Actual & Projected O&M Expenses – Customer Experience, Customer Operations: Customer Interactions; and |
| Confidential Exhibit A-38 (JRB-3) | Summary of Actual & Projected O&M Expenses – Third-party ASP. |

**Q. Were these exhibits prepared by you or under your supervision?**

A. Yes.

**Q. Please describe Exhibit A-12 (JRB-1), Schedule B-5.3.**

A. Exhibit A-12 (JRB-1), Schedule B-5.3, details the capital expenditures related to direct work within the CX&O organization, which totaled $111,000 in the historical year, $1 million projected in the bridge period, and $1.9 million projected in the test year. This reflects a financial forecast based on the work plan and designated development activities within the Customer Billing and Credit and Assistance areas.

Please note that this testimony also discusses the Customer Information Technology ("IT") project benefits related to the capital spend sponsored by IT Company witness Stacey H. Baker.

**Q. Please describe Exhibit A-37 (JRB-2).**

A. Exhibit A-37 (JRB-2) details the O&M expenses related to work within the CX&O organization, which total $32,000,000 for the test year ending October 31, 2026.

**Q. Please describe Confidential Exhibit A-38 (JRB-3).**

A. Confidential Exhibit A-38 (JRB-3) details the O&M expenses related to work within the third-party Appliance Service Plan ("ASP") space, with a total reported margin of $1.3 million for the test year ending October 31, 2026.

**Q. Please describe Exhibit A-37 (JRB-2) page 4.**

A. Exhibit A-37 (JRB-2), page 4, is a hypothetical illustration of the CX&O projected O&M expenses based on Inflation. This page is for illustrative purposes only and not intended to represent how the Company has developed its projected CX&O O&M. Column (b) shows the historical O&M expense. Column (c) shows the historical amount to which an inflation rate or merit increase rate was applied. Columns (e) and (g) show the amounts to which a hypothetical inflation rate or merit increase rate were applied for each bridge period, respectively. Columns (d), (f), and (h) show the hypothetical merit and inflation increases for each respective period. Because the Company does not develop the projected CX&O O&M using inflation it is necessary to include column (i), other adjustments. Column (i) is simply the difference between the Company's actual projected O&M and what the O&M would have been if the Company had used inflation to project CX&O O&M. Column (j) is the projected test year O&M and is the sum of columns (b), (d), (f), (h), and (i). The expenses that I am supporting are based upon the expenses necessary to meet the needs of the various projects and department operations planned in the test year and are not based on applying an inflation rate to the historical O&M expenses.

**Q. Please describe how the CX&O budgets and projected O&M expenses are developed.**

A. The budgets are prepared using a zero-base accounting method, meaning that they are prepared with no reference to any prior year's budget. To accomplish this, CX&O starts from zero and adds the expenses associated with the projects and department operation planned to complete in the test year to arrive at the final projected test year spend. By contrast, to conform to the Company's exhibit standard, Exhibit A-37 (JRB-2), page 4, must not start from zero but must instead start from historical year actuals, and, as a result, must have the "Other Adjustment" variable applied to it so that the final projected test year

spend is the same as what is shown in the CX&O budget. Figures in this column should *not* be disallowed as though they are unjustified expenses. They do not exist as a category of spending, but merely reflect the difference in calculation methods between the CX&O budget and the hypothetical illustrations discussed above. Amounts included in the "Other Adjustment" column will be discussed throughout my testimony in the corresponding business area.

**Q. Please provide a summary of the CX&O O&M expenses and capital investments projected in the test year.**

A. CX&O is projecting capital expenses of $111,000 in the historical year, $1 million projected in the bridge period, and $1.9 million projected in the test year, as mentioned above, and $31.8 million in O&M expense for the test year ending October 31, 2026. This amount comprises $21 million of O&M expenses for Customer Interactions, and $10.8 million for Billing and Payment. The CX&O O&M expenses are presented in detail on Exhibit A-37 (JRB-2). The historical and projected capital costs for these programs are included in Exhibit A-12 (JRB-1), Schedule B-5.3.

| **DEPARTMENT** | **CAPITAL** | **O&M** |
|---|---|---|
| Customer Interactions | $1.9 million | $21 million |
| Billing & Payment | $0.0 | $10.8 million |
| **Total** | **$1.9 million** | **$31.8 million** |

The Company is also projecting $438,000 in capital and $156,000 in O&M for customer capital investments in the test year to support the CX&O IT infrastructure. All IT-related capital costs discussed herein are in the IT budget and discussed by Company witness Baker.

**Q. Has the Company undertaken any initiatives to lower costs related to CX&O O&M expense?**

A. Yes. Incorporated into the CX&O O&M projection is $9 million of net recurring customer benefit to the gas business due to changes to the payment process. This is the result of implementation of a fee-based model for payments submitted through vendor payment channels to ensure the cost distribution for payments is fairly represented between residential customers and non-residential customers who choose to pay with a high-cost payment method or fee-based channels versus those who use fee-free payment methods.

**Q. Are there remaining savings from the Company's Voluntary Separation Plan ("VSP")?**

A. Partial year VSP savings (August-December) are still reflected in 2023 actuals, while the bridge and test year forecasts in my exhibits will also include VSP savings carried over from reduced headcount. Note that those savings are offset by yearly merit increases for remaining personnel.

**Q. How is the remainder of your testimony organized?**

A. My testimony is organized as follows:

I. Customer Experience and Operations

A. Customer Interactions

B. Billing and Payment

## I. CX&O

**Q. Please describe CX&O.**

A. The CX&O organization strives to optimize the gas customers' positive experience when interacting with the Company. It has two major components - Customer Interactions and Billing & Payment. Customer Interactions ensures that customers are equipped to connect

with the Company in their preferred channel (phone, Interactive Voice Response ("IVR"), website, mobile app, or digital correspondence— such as text messages). Billing & Payment provides customers with accurate, punctual energy bills and consistent payment processes, and arranges personalized payment plans or settings (e.g. inability to pay arrangements, pay by phone/website, payment alerts, choose your own bill due date) for individual customers.

These two core functions are fundamental to accomplishing the Company's customer experience goals. The Company relies on its array of customer experience offerings to ensure that customers are satisfied when interacting with Consumers Energy and are therefore positively inclined to enroll in its available clean energy programs. The Company recognizes the energy industry is increasingly expected, and committed, to pursuing clean energy and believes that customer engagement and participation is critical to realizing this future.

**Q. Is the Company's IT witness sponsoring any Customer projects?**

A. Yes. Company witness Baker is sponsoring test year funding for two Customer-related technology projects totaling $438,172 in capital expenditures and $156,343 in O&M expenses. Please see Company witness Baker's testimony for additional information.

The IT department is a critical CX&O partner and CX&O relies on IT expertise to help develop and implement necessary digital solutions. IT maintains the Company's technology systems, ensuring they operate efficiently, reliably, and free from cybersecurity risks. IT also supports analytic platforms and solutions that provide deeper insight into customer needs, enabling CX&O to establish appropriate targets for metrics, products, and customer programs, which are necessary to allow CX&O to select the most cost-effective and beneficial solutions for customers. Together, these departments ensure customers

receive secure, reliable, and positive experiences across all channels of interaction with the Company. Continued investment in technology requires additional ongoing funding to initiate, support, and maintain these platforms. Cross-references to CX&O projects are noted below.

| PROJECT | CAPITAL | O&M | JRB-Testimony Reference |
|---|---|---|---|
| Customer Order Service Tracker | $438,172 | $150,951 | DCO – page 11 |
| Genesys Cloud Migration | $0 | $5,392 | DCO – page 13 |
| **Total** | **$438,172** | **$156,343** | |

### A. Customer Interactions

**Q. Please provide an overview of Customer Interactions.**

A. Customer Interactions is responsible for the ownership and execution of all channels of customer interactions as identified above. This work includes the following areas of focus: Digital Customer Operations ("DCO"), Customer Contact Center, Business Customer Care ("BCC"), and Credit and Assistance. All are aligned to the larger department goals of: (i) providing customers the opportunity to interact with Consumers Energy via their channel of choice; (ii) facilitating program enrollment and product selection to meet customer energy needs; and (iii) achieving the Company's clean energy goals. To effectively perform in these areas, the Company is projecting $21 million of O&M expenses and $1.9 million in capital for the test year ending October 31, 2026, as shown on Exhibit A-37 (JRB-2).

**1. Digital Customer Operations**

**Q. Please provide an overview of DCO.**

A. DCO is responsible for the operation and continuous improvement of the Company's customer-facing digital applications, including its website and mobile application. The DCO team collects over 2,900 points of customer survey feedback every month, which drives the team's priorities in four simultaneous work cycles: (1) small, agile digital changes using available tools; (2) managing the design, development, and launch of monthly releases to add new features or modify user flows; (3) leading major technology projects that add new or modify existing functionality to better serve customers; and (4) executing the implementation of programs online to help accrue energy savings and clean energy opportunities for customers.

To continue this work, the Company is projecting $1.1 million of O&M expenses for the test year ending October 2026. As shown on Exhibit A-37 (JRB-2), this represents a decrease in O&M expenses of $800,000 from the $1.9 million expended in 2023. The primary driver of this is a decrease in contractor-related costs.

**Q. What types of transactions do customers complete online?**

A. The most common transactions customers complete using the Company's website and mobile app are: (1) checking the billing status of their account (12.8 million views in 2023); (2) making payments (13.3 million views in 2023); (3) reporting outages or view the status of an outage (4.7 million views in 2023); (4) checking energy usage information (1.3 million views in 2023); and (5) investigating additional service information—such as auto-pay, eBill enrollment, budget billing, and information on products and services. The Consumers Energy website also serves as the principal vehicle to enable customers to sign

up for clean energy program rebates, enroll in energy saving programs, and save money with energy-efficient products.

**Q. Please explain why the Company is continuing to invest in multiple digital methods to allow customers to complete transactions or find information in their channel of choice.**

A. The Company continues to invest in multiple digital methods for customer interaction for several reasons. Continued investments are needed to keep pace with changes in customer needs, habits, and expectations at the same time customer use continues trending toward more integrated and sophisticated digital services. These investments also ensure channel parity so that customers can complete all transactions in all channels. Additionally, expanding the Company's digital channel lets customers complete a variety of activities on a smartphone or computer at a time that may be more convenient than the limited call center service hours, shifting costs to the more cost-effective channel. In 2023, customers paid $4.7 million of bills through the web and mobile app daily. Both channels together are on track to see $1.7 billion in payments yearly. Online transactions cost approximately $0.11 versus $9.22 per live agent call (utilizing internal contact center resources), making this a cost-effective alternative to expanding the call center service hours.

The Company's digital channels are critical systems requiring proper levels of support to ensure they function when and how customers need them. It is important to note that, like most peer institutions for which this has become the customer expectation, the Company continues to support several channels in response to customer needs and choices for communicating and completing transactions. The Company's IVR System currently co-exists in the digital platform space with the website/mobile website and the mobile app. Similarly, the Company maintains call centers and direct payment offices for customers

who prefer to communicate or pay face-to-face. Many of these channels are maintained in service of the wide variety of customer needs given generational, locational, and socio-economic factors.

**Q. Is the CX&O department proposing test year IT costs related to DCO projects?**

A. Yes. Company witness Baker is sponsoring test year capital IT costs for two DCO projects: (i) $438,172 in capital and $156,343 in O&M costs in the test year for the Company's Customer Order Service Tracker, and (ii) $55,000 in O&M for Genesys Cloud Migration. The customer benefit of each project is discussed below.

**CUSTOMER ORDER SERVICE TRACKER**

**Q. Please detail the Customer Order Service Tracker.**

A. The Customer Order Service Tracker will implement a service order status tracker to provide both transparency to customers and oversight to internal teams supporting utility service orders across Company service areas. The tracker will provide timely and accurate service order updates, creating a more robust customer experience for tracking service order status and crew location updates, as well as an interactive digital channel for use by dispatch, scheduling, and field crews.

Many incoming customer inquiries include "short cycle" orders, such as questions about or reports of emergencies, forestry needs, or meter services issues. Customers may have very limited visibility into when Company-assigned crews will be onsite for this work due to a current lack of relevant features within the Company's digital channels that can track and report accurate updates from dispatch, scheduling, and field crews. The lack of awareness drives thousands of short cycle request-related calls into the call center.

Additionally, current lack of visibility by dispatchers increases truck rolls because they have limited awareness of crew locations and routes, which can cause crews to be

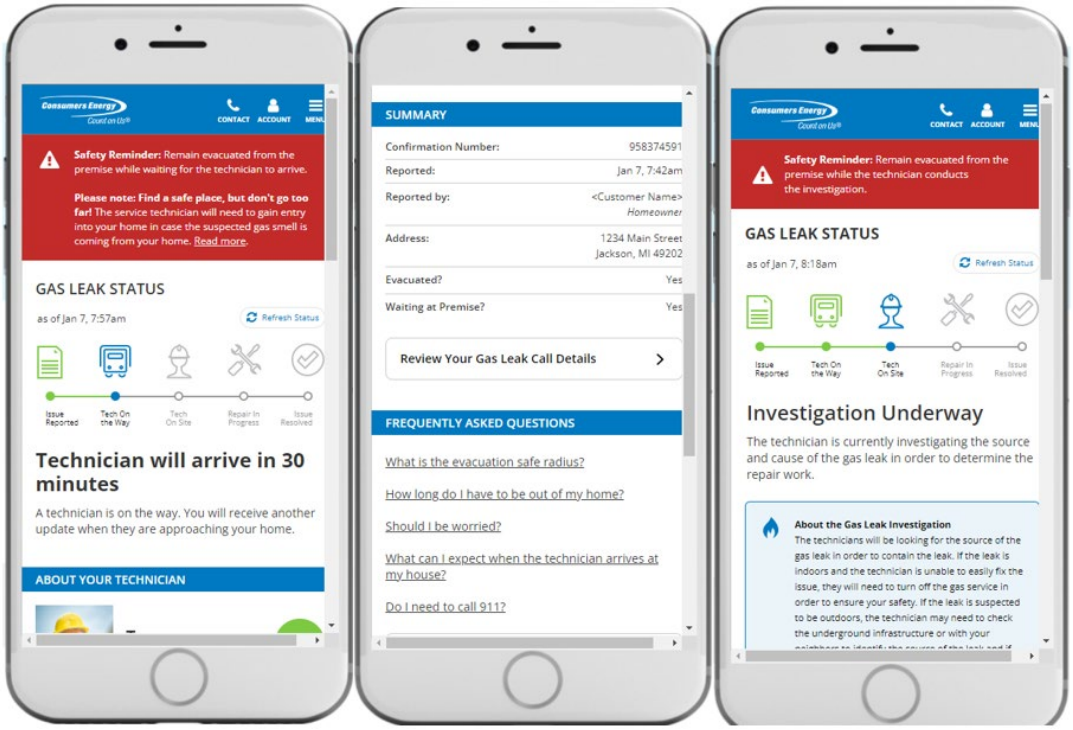
assigned improperly. Enabling a digital channel for utility service order communication for both customers and dispatchers will improve customer experience and reduce the waste of repetitive crew dispatching.

**Q. Why is this project important in the customer space?**

A. This project will add value to the Company and its customers by: (1) providing transparency for customers on the timing and location of the associated crew completing utility service orders; (2) reducing calls to contact centers by customers seeking clarification regarding arrival times through visibility to scheduling timeframes and providing notifications to customers when crews are enroute; (3) improving resource assignment by current location, which decreases wasted truck rolls through enabling location services for active crews; (4) increasing visibility into the service person(s) completing the order by enabling crews to connect with customers through digital channels; and (5) improving customer experience for short-cycle service orders by implementing a channel of choice for Company interactions.

Helping the customer to understand where their request is in the process reduces frustration by providing a clear view into their order. This project seeks to offer a simple, informative option which the customer can easily access and check.

The images below are mock-ups of the potential user experience flow, designed around a mobile device user in a gas leak emergency.




**Q. Are there additional benefits to the Customer Order Service Tracker?**

A. This project will provide transparency on the timing and location of the assigned crew completing utility short-cycle service orders. As a result, use of the tracker will reduce calls from customers seeking clarification by scheduling and communicating arrival timeframes and providing notifications when crews are in-route; improve resource assignment, decreasing wasted truck rolls; and allow crews to connect with customers through digital channels.

## GENESYS CLOUD MIGRATION

**Q. Please detail the Genesys Cloud Migration Project.**

A. Genesys, the Company's on-premises software solution for receiving and managing customer phone calls, is in need of costly upgrades but vendor support for the tool will end in 2028, with no option for extended support. Without such support, the system will no longer receive critical security patches or software "bug fixes" from the vendor which then

creates significant security, stability, and reliability risks in addition to limiting the Company's ability to invest in new functionality to better serve customers. This project will migrate the Company's existing solution to the cloud, ensuring that vendor security patches, bug fixes, updates, and enhancements are deployed as necessary, allowing the Company to ensure continued support for this critical customer communication channel.

In addition to continued support, the Company will save approximately $150,000 in managed service costs and over $1 million in licensing costs over the next three years, while also avoiding the significant costs necessary to maintain an on-premises solution. The cloud solution will also allow the Company to take advantage of new enhancements offered by the vendor and ensure continued support of a critical customer communication channel.

**CUSTOMER PRODUCT FAMILY ENHANCEMENTS**[1]

**Q. Please describe how Customer Product Family enhancements are identified and implemented.**

A. CX&O Customer Product Family Enhancements are technology improvements which benefit customers and are implemented in response to the launch of a channel, customer tool, project completion, and/or direct customer feedback. Depending on the need identified, enhancement dollars could be utilized to support the enhancement of any customer supporting feature and/or capability, often as emerging requests. These items are small-scope items with a reduced budget and fewer resource requirements in comparison to larger capital investments. Having the flexibility to implement Customer Product

[1] For 2021 and 2022, the actual project name was Enhancements-CX&O-Capital and starting in 2023, the project is named Product Family Enhancements-Customer-Capital.

Family Enhancements enables the Company to meet emerging needs without the longer lead time of rate case submissions.

Examples of enhancements include improving overall functionality of the channel or tool, analytics on platform usage, addressing issues identified internally or via customer feedback, adding relevant or customer-driven capability, and performance monitoring.

**Q. How do Customer Product Family Enhancements benefit the Company's customers?**

A. Enhancements assist the Company in providing a better, more optimized customer experience for customers through improved understanding of how they use the channels or tools, which features are important to their experience, and how the channels or tools are performing. Specific enhancements are discussed throughout my testimony in the corresponding business area and IT Company witness Baker's testimony.

### 2. Customer Contact Center

**Q. Please provide an overview of the Customer Contact Center.**

A. The Customer Contact Center is responsible for staffing and operating the Company's call centers, which serve all residential and small business customer calls. In 2023, call center representatives answered over 2.75 million customer calls. Likewise, the IVR system addressed 5.1 million calls in 2023.

To continue this work, the Company is projecting $13.2 million of O&M expenses for the test year ending October 2026. As shown on Exhibit A-37 (JRB-2), this represents an increase in O&M expenses of $245,000 from the $13 million expended in 2023. Most of the increase is due to increased contractor cost.

### 3. Business Customer Care

**Q. Please provide an overview of BCC.**

A. BCC directly impacts the Company's commercial and industrial ("C&I") customers, and includes the Business Center, which assists the Company's larger business customers with support such as phone agents and account management. BCC's main goal is to deliver an exceptional customer experience, while identifying opportunities that provide the Customer with added energy value and opportunities. Overall, BCC serves approximately 100,000 customers, equating to 200,000 contract accounts.

To continue the work in this area, the Company is projecting $1.78 million in O&M expenses for the test year ending October 2026. As shown on Exhibit A-37 (JRB-2), this represents a decrease in O&M expenses of $50,000 from the $1.83 million expended in 2023, with the decrease attributed to lower labor costs in this area.

### 4. Credit and Assistance

**Q. Please provide an overview of Credit and Assistance.**

A. Credit and Assistance consists of: (1) Theft Investigations; (2) Revenue Operations; and (3) Energy Assistance, which collectively manage the Company's collections cycle and support its most vulnerable customers by connecting them with Company-sponsored payment plans and public assistance funding to help customers pay their bills.

The Theft Investigation Team provides the critical service of identifying and ending energy theft in the Company's service territory - important both for maintaining the safety and integrity of the Company's system and minimizing all customers' costs. In 2023, the team identified 2,797 confirmed cases of theft and billed for $1,145,650.81 in unauthorized use and investigation costs - an increase of 1,487 cases and an increase of about $473,000 billed over the previous year.

Revenue Operations addresses past due customer accounts or those involved in bankruptcy. Employees within this area manage the collections cycle, beginning with issuing a notice to customers and ending with visiting their premises to disconnect service. This group also manages contracts with outside collection agencies to recover payments from customers with outstanding balances. In 2023, the Company contracted with outside collection agencies for $2.1 million (covering recovery for both gas and electric accounts). Consequently, the agencies recovered $8.8 million of previously written-off customer balances, of which $2.9 million accounted for *gas-only* recoveries (33% of total). Recovery of these payments directly offsets the uncollectible expense discussed in the testimony of Company witness Matthew J. Foster.

The Energy Assistance team is responsible for administering the Company's Consumers Affordable Resource for Energy ("CARE") Program, which supports low-income customers who may be struggling to pay their monthly energy bills and helps to provide customers with either a one-time bill assistance payment or on-going support via enrollment in an Affordable Payment Plan ("APP"). By coordinating with other organizations in fiscal year 2023, this team obtained $10.4 million of APP-specific assistance and an additional $9.2 million in one-time assistance for its customers requested through the Michigan Energy Assistance Program ("MEAP"). These plans offer customers reduced monthly bills and gradually pay down any arrears brought into the program. In addition to MEAP assistance, customers received $37.8 million in State Emergency Relief payments and $18.9 million in Home Heating Credit assistance. Note these figures include assistance for both electric and gas customers.

To continue the work in this area, the Company is projecting $2.6 million in O&M expenses and $1.9 million in capital for the test year ending October 2026. As shown on

Exhibit A-37 (JRB-2), the O&M request represents an increase of about $300,000 in O&M expenses from the $2.3 million expended in 2023, due to increased labor and contractor costs.

**Q. Please provide additional details about the $1.9 million in capital spending in this area.**

A. The capital request is to support the Low Moderate Income ("LMI") Customer Support Enhancement.

**Q. Please describe the LMI Customer Support Enhancement project.**

A. The LMI Customer Support Enhancement project aims to provide solutions that make interactions more accessible, supportive, and efficient, while facilitating enrollment into assistance programs to reduce energy burden for LMI customers. This project will facilitate reaching customers earlier and significantly easing the enrollment process to payment assistance and income-qualified programs including budget plan, payment arrangements, shut-off protection, home energy audits, helping neighbors, demand response, renewable energy and more, by (1) implementing a streamlined, self-attestation workflow that allows customers to find and enroll in *all* relevant assistance programs, and (2) building the capability to proactively identify and reach out to customers who are showing early signs of crisis, educating them about assistance options and directing them to the streamlined, digital workflow. This project aims to address identified barriers to earlier LMI interaction and enrollment in utility programs.

**Q. What is the purpose of the LMI Customer Support Enhancement project?**

A. The LMI Customer Support Enhancement project is designed to support low and moderate-income customers to reduce their utility bill expenses by driving greater awareness and enrollment into eligible programs and services. The central purpose is to

alleviate the energy burden customers face to improve household stability and reduce the risk of service disconnections due to unpaid bills.

**Q. Why is it important for the Company to receive approval for this project?**

A. This project will directly improve the customer experience by supporting a significant portion of the Company's customer base: low- to moderate-income customers. LMI customers account for more than one of every three customers in Consumers Energy's service territory; 11% are low income, meaning they are in crisis and unable to pay their energy bill; 26% are moderate income, commonly identified as being one crisis away from being able to pay their energy bill. Currently, only one in six LMI customers engage in Consumers Energy Assistance programs with the majority of these interactions driven by immediate crises that limit ability to introduce solutions and programs given the urgent customer need. Further, interactions at near crisis and crisis moments impacts trust, often resulting in customers being less receptive and open to solutions the Company can offer or provide access to.

Moreover, approval of this project delivers on the priorities of the MPSC's Energy Affordability and Accessibility Collaborative (EAAC) and Low-Income Energy Policy Board that highlight the importance of streamlining energy assistance and program enrollment processes to support increased awareness, participation, and customer benefit. This need for attention to simplified and effective processes is also highlighted in Public Act 229 of 2023, which instructs utility EWR programs to minimize barriers to participation in low-income EWR programs and reduce overly burdensome verification processes.

Overall, this work will provide proactive, immediate relief, helping these customers manage costs, avoid disconnection, and maintain essential services. All of which will

enhance customer well-being making it a socially responsible initiative with tangible, positive outcomes.

**Q. Describe the customer research used to develop the project.**

A. To address the dynamics previously stated, the Company initiated primary and secondary research to better understand LMI customers to identify barriers, increase awareness about assistance options and increase participation in utility programs. The Company used existing research from a variety of partners which established a clear need for the LMI Project, and the LMI project team then undertook primary research to validate and refine the learnings. The primary research included more than 2,000 LMI customers, 95% of whom live in Michigan. Through surveys, interviews, and ethnographic studies these customers shared insights on their experiences, challenges, and expectations, ensuring the project is informed by the voices and needs of those it aims to serve.

Research findings revealed that 18% of LMI customers are unaware of how to access help, 36% are unaware they qualify for programs, 25% perceive the process as overly complex and time-consuming, 51% feel too overwhelmed to take on another project, 21% consider EWR programs to be price-prohibitive, and 46% are unfamiliar with utility assistance for low-income families. Furthermore, research from a 2024 Los Angeles Dept. of Water and Power case study showed that using income self-attestation increased program enrollment and willingness to initiate assistance requests by 40%. Customer research was foundational in the development of this project to ensure outputs are not only accessible and effective but also directly address the needs and preferences of LMI customers, ultimately making it a valuable tool for reducing utility bills and supporting financial stability.

**Q. How will investment in this project benefit customers?**

A. While this project's primary focus is to support LMI households, its results will benefit all customers. There are five key customer benefits this project will deliver. First, enhancing energy equity: by broadening access to bill assistance and utility programming this solution gets us one step closer to ensuring everyone has equal access to basic utilities. Second, addressing the risk of unpaid bills and service disconnections isn't just compassionate and the right thing to do, it's also cost-effective; preventing service cuts reduces administrative costs and lost revenue which will positively impact all customers. Third, building trust with LMI customers fosters a sense of loyalty and increases their willingness to engage proactively, not just in times of crisis. Fourth, reducing the bill and energy burden on low-income families enhances their overall quality of life and financial stability. Finally, engaging LMI households not only in bill assistance programs but also in clean energy solutions is crucial for environmental sustainability aligning with the Company's Clean Energy Plan and the state's MI Healthy Climate Plan. Together, these benefits not only support vulnerable customers but also create a more cost-effective and sustainable future for everyone.

**Q. Does this project have internal approval?**

A. Yes.

**Billing and Payment**

**Q. Please provide an overview of Billing and Payment.**

A. Billing and Payment is responsible for leveraging customer feedback to ensure payment processes are simple and consistent, monthly energy bills are accurate and easy to understand, and customers receive their bills in a timely fashion. The work in this department is divided between Customer Billing and Customer Payment programs. The

Company is projecting $10.9 million of O&M expenses for the test year ending October 2026. As shown on Exhibit A-37 (JRB-2), this represents a decrease in O&M expenses of approximately $4.2 million from the $15 million expended in 2023. This decrease is mainly due to the Company's policy shift in assessing credit card fees.

### 1. Customer Billing

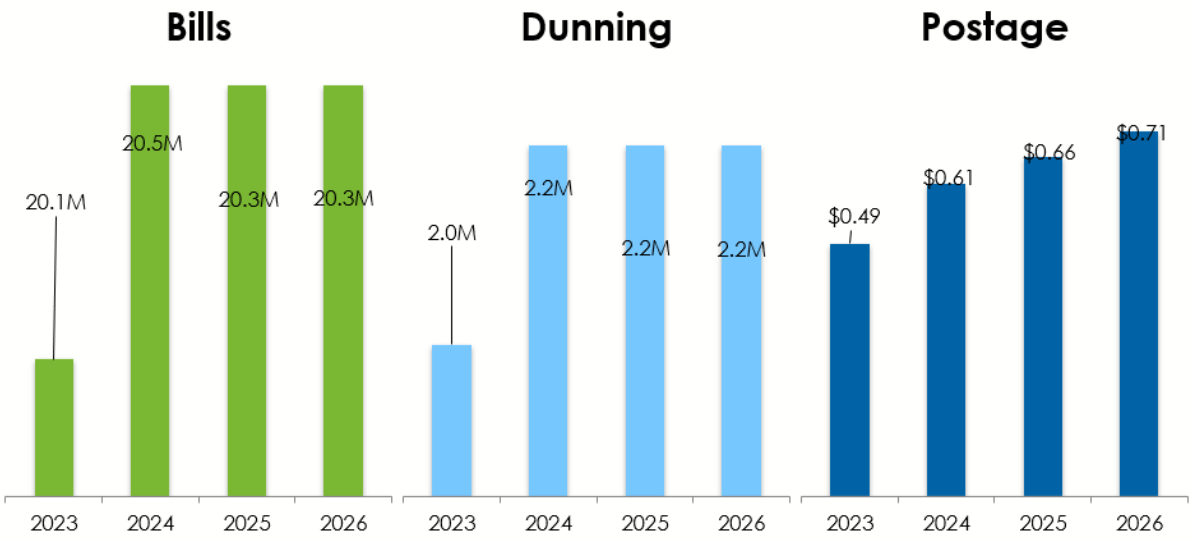
**Q. Please provide an overview of Customer Billing.**

A. Customer Billing manages the exceptions process - a quality control process designed to (1) review unusual bills (both digital and paper) and/or (2) bill for unique programs before they are sent to customers. The review may involve contacting customers to gather additional information or to inform them of a potential billing issue. Bills may be corrected through the billing adjustment process, or meters may be reread as part of the validation process. Rigorous efforts to ensure every customer bill is accurate results in the Customer Billing team continually optimizing its processes and technology to aid in the billing exception review. Ensuring that customers receive the right bill every time is critical. To continue this work, the Company is projecting $9.5 million of O&M expenses for the test year ending October 2026. As shown on Exhibit A-37 (JRB-2), this represents an increase of $805,000 from the $8.7 million expended in 2023, due to a US Postal Service postage increase in 2024 as well as a projected increase in 2025.

**Q. Please explain the costs within Customer Billing.**

A. The cost for stationery, forms, and postage related to the Company's billing and dunning communication processes is included in Customer Billing. In 2023, the Company mailed nearly 20.5 million paper bills, and approximately 2 million dunning notices. As illustrated in Figure 1 below, the Company has incurred increased postage rates in recent years, and the increased costs of additional dunning notices being mailed.

*Figure 1. Current and Projected Dunning and Postage Costs*




To mitigate these cost increases, the Company has taken action to increase customer enrollment in electronic billing, or eBill. Consumers Energy has successfully increased eBill participation from <27% in 2017 to 48% as of the fourth quarter of 2023. This growth has offset postage costs by over $2.5 million annually by reducing the number of pieces mailed.

However, cost per piece of postage has steadily increased over the past three years, a cost expected to continue to increase due to US Postal Service postage increases. These increases offset the savings the Company has realized from growing its eBill enrollment, without which increases in the cost for postage would have contributed to the cost of customer billing over time. In addition, as shown in Exhibit A-37 (JRB-2), the Company invested $1,078,000 in the bridge period on printers used for two large-scale customer bill printer replacements. Two of the Company's printers reached the end of life in 2023, and it was necessary to replace them to continue to be able to provide customers with appropriate and timely bills.

**2. Customer Payment Programs**

**Q. Please describe the CX&O Customer Payment Programs group.**

A. Customer payments are among the most sensitive and frequent touchpoints the Company has with its customers, with approximately 34 million payments made annually. The Company's Customer Payment Strategy focuses on removing payment difficulties, providing payment options that customers expect, and ensuring all customers have the same easy payment experience regardless of how they choose to pay their bill. This has resulted in a significant reduction of payment-related calls and complaints and improvement in customer experience. The Company continues to make it a priority to accommodate customer preferences with a variety of desirable options to meet current customer expectations and to maintain a single set of customer-friendly payment rules that apply across all payment options.

**Q. Please describe the costs associated with the Customer Payment Programs.**

A. The Company is projecting $1.4 million in the test year O&M expenses shown on Exhibit A-37 (JRB-2). This represents a $5 million decrease from the $6.4 million expended in 2023. The decrease is mostly due to ending the socialization of credit card fees. Operating costs associated with customer payments continue to evolve with changes in customer behaviors and preferences.

**Q. What are the anticipated payment processing fees costs for the test year?**

A. Within the $1.4 million of Customer Payment Programs test year O&M expense, the Company is projecting $192,766 in payment processing fees O&M expenses for the test year. Additional payment-related fees include bank lock box fees in the amount of $364,560, approximately $497,169 in Direct Payment Office ("DPO")-related payment fees, and $321,412 for the Billing & Payment Program Support team.

**Q. Are there additional changes to the way the Company collects payment processing fees?**

A. As discussed above, the Company has implemented a policy change, resulting in a fee-based model for payments submitted through vendor payment channels.

**Q. Does the Company anticipate any revenues generated by assessing payment card service fees to customers continuing to pay with a credit/debit card?**

A. No, the Company does not anticipate or forecast any revenue being generated from payment processing fees.

**Q. What are the merchant fees that customers pay for use of credit/debit cards?**

A. All customers using credit/debit cards pay a flat fee per transaction. Residential customers pay $2.99 per transaction and C&I customers pay $9.99 per transaction, regardless of rate schedule. These fees are paid directly to the third-party payment processor, Paymentus.

**Q. Please provide an overview of DPOs.**

A. Consumers Energy has eight DPOs around the state of Michigan, all located within existing Company facilities, making them a cost-effective option for customers to pay their bills in person. These offices serve some of the Company's most vulnerable customers, such as seniors and low-income customers, providing them with a community resource that can connect them with billing options and assistance opportunities.

**Q. Does the Company offer other in-person payment options in addition to the remaining DPOs?**

A. Yes. The Company has maintained its relationship with an authorized pay agent, which accepts payments at stations such as Wal-Mart, Kroger, and other associated store fronts. These pay stations serve as de facto DPOs. This provides customers with the continuity and convenience of being able to pay their bill without having to locate a DPO. Customers

are charged a fee to pay their bill in these locations, which covers the costs of the processing fee the Company is charged to have this option.

**Q. Does the Company itself collect the payment fee?**

A. It does not. The authorized pay agent implements and collects the fee from the customer utilizing their services.

**Q. What is the payment fee?**

A. The payment fee is $1.50 per transaction, per the agreement between the vendor and the Company.

**HOME ENERGY PRODUCTS PROGRAM**

**Q. Please describe the Company's Home Energy Products Program.**

A. Home Energy Products referred to a portfolio of value-added products and services ("VAPS") that consists of the Company's non-regulated ASP, appliance repair, and the AllConnect Mover Program. Customers enrolled in ASP paid a monthly subscription fee to cover repairs to equipment such as furnaces, air conditioners, etc. and if a covered appliance malfunctioned, a qualified service person was sent to explain/rectify the problem at no additional cost to the customer. This program benefitted customers by reducing the risk of potentially expensive and unexpected appliance repair or replacement costs.

**Q. In the Company's last gas rate case (Case No. U-21490), Company witness Heidi J. Myers and Steven Q. McLean testified regarding the sale of portions of the Company's Home Energy Products Program. Was the sale successfully completed?**

A. Yes. The sale was successfully completed.

**Q. Were the proceeds shared with customers as detailed in U-21490?**

A. Yes. The proceeds were shared with customers as defined in the Commission's July 23 Order in Case No. U-21490, approving a settlement agreement that states:

> The parties agree that Consumers Energy shall share 100% of the net upfront gain of approximately $110 million with customers in the following manner, without interest. $27.5 million, or one fourth of the net upfront gain, shall be used as an offset to the revenue deficiency in lieu of additional rate relief during the test year. The remaining three fourths of the net upfront gain, approximately $82.5 million, will be credited back to customers, through the Home Products Credit over a three-year period starting with the test year . . .

[Start Confidential]

[redacted]

[End Confidential]

**Q. Does this complete your direct testimony?**

A. Yes.

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

| | | |
|---|---|---|
| In the matter of the application of **CONSUMERS ENERGY COMPANY** for authority to increase its rates for the distribution of natural gas and for other relief. | ) ) ) ) ) | Case No. U-21806 |

**REBUTTAL TESTIMONY**

**OF**

**JESSICA R. BYROM**

**ON BEHALF OF**

**CONSUMERS ENERGY COMPANY**

May 2025

**Q. Please state your name and business address.**

A. My name is Jessica R. Byrom, and my business address is One Energy Plaza, Jackson, MI 49201.

**Q. Are you the same Jessica R. Byrom who previously submitted testimony in this case on behalf of Consumers Energy Company ("Consumers Energy" or the "Company")?**

A. Yes.

**Q. What is the purpose of your rebuttal testimony?**

A. The purpose of my rebuttal testimony is to rebut the direct testimony of Michigan Public Service Commission ("MPSC" or the "Commission") Staff ("Staff") witness Brittany Klocke on the topics of the Company's Low and Medium Income ("LMI") Customer Support Enhancement project and its Customer IT and IT Enhancements; Attorney General witness Sebastian Coppola's testimony regarding operating and maintenance ("O&M") for Customer Digital Customer Operations ("DCO") and Analytics and Outreach work, Michigan Environmental Council ("MEC") and Sierra Club ("SC") (collectively "MEC") witness Alice Napolean's testimony that discusses the Company's energy waste reduction ("EWR") programs, and Citizen's Utility Board of Michigan ("CUB") witness Joshua W. Denzler's testimony regarding the Company's Customer Order Service Tracker ("COST") project and associated O&M.

**Q. Are you sponsoring any exhibits?**

A. Yes. I am sponsoring the following exhibits:

Exhibit A-129 (JRB-4) LMI Mindset Map.

**Q. Were these exhibits prepared by you or under your supervision?**

A. Yes.

**Staff Witness Klocke Regarding LMI**

**Q. Starting on page 13, line 20 of her testimony, Staff witness Klocke has recommended disallowance of $1.9 million in capital for the Company's Customer-based LMI Customer Support Enhancement project. How does the Company respond?**

A. The Company disagrees with Ms. Klocke's assertion that the expenses related to this LMI project are unjustified. 36% of all Consumers Energy customers assume they are not eligible for utility payment assistance, 33% lack awareness of available assistance, and 18% do not know where to start the application process. The project will allow the Company provide assistance to customers in a thoughtful, prescribed manner. Additionally, as an active participant in the MPSC's Low-Income Energy Policy Board, Energy Affordability and Accessibility Collaborative ("EAAC") and EWR Low-Income Workgroup, the Company has planned and executed this project to align with the priorities for assisting LMI customers, responding directly to the EAAC's key area of focus including "strategies for streamlining the energy assistance process; and recommendations on tying energy waste reduction to energy assistance.[1]"

**Q. Why is the LMI project's alignment with the MPSC's EAAC and EWR Low-Income Workgroup important?**

A. Alignment with the EAAC and EWR Low-Income Workgroup is important because it ensures that this project reflects the needs of the most vulnerable customers and is grounded in best practices developed through statewide collaboration. Parties within these groups represent a broad cross-section of stakeholders, including residents, non-profits, utilities, and state agencies, all holistically working toward assessing energy affordability and

[1] https://www.michigan.gov/mpsc/commission/workgroups/energy-affordability-and-accessibility-collaborative

accessibility, particularly through linking EWR services and energy assistance programs. Their work has produced clear, data-informed recommendations and guiding principles that define what effective, just, and sustainable energy assistance should look like in Michigan. The Company's LMI project responds directly to these recommendations to deliver a solution that reduces duplication of customer efforts while seeking assistance, aligns with State programs, and is grounded in the needs and best practices identified by these collaborative groups.

**Q. Beginning at page 14, line 14, of her direct testimony, Staff witness Klocke states "through numerous rounds of audit questions, to ascertain exactly what the LMI Customer Support Enhancement will do or will offer customers and still does not have a clear answer." Has the LMI project implementation produced a more dependable project scope for what it offers customers?**

A. Although the LMI Customer Support Enhancement project was in development and early implementation at the time of the Company's initial filing, it has now been operational for four months. In that short time, the project has clearly demonstrated its value in improving access to assistance for all Consumers Energy customers.

The project has already seen a measurable increase in customer engagement and uptake—indicators that the tool is well-designed to meet the needs of the population it is intended to serve. Since its launch on December 12, 2024, over 55,000 customers have interacted with the tool, and 12,000 customers have enrolled in an offering, with 22% of interested customers enrolling in programs (compared to .05% of customers who enroll after being reached via email), ensuring that the efforts put into developing and promoting the tool are yielding tangible benefits. Given its strong foundation, evidence-based design,

immediate positive outcomes, and clear trajectory for ongoing improvement, this LMI project is a reasonable and prudent investment. Funding it now ensures that the Company can continue delivering meaningful support to customers who need it most.

**Q. Can the Company provide results that demonstrate effectiveness and progress toward the stated goals of the LMI project?**

A. Yes. Since its launch, the LMI project has delivered several measurable outcomes that demonstrate its early effectiveness and validate the Company's approach. Within the first four months of deployment:

- Over 55,000 customers have engaged with the tool since launch, and nearly 30,000 (55%) of those users have self-identified as LMI, indicating high visibility within and interest from the intended user base.
- Of the 55,000 customers who have interacted with the tool roughly 40% completed the full eligibility assessment, successfully identifying one or more programs for which they may qualify.
- Of the 12,000 users completing the flow, nearly 20% have enrolled in more than one offering, demonstrating the effectiveness of the simplified digital enrollment flow in making it easier for customers to access the programs they need.
    - By streamlining the process, customers can quickly and efficiently determine their eligibility and enroll in multiple beneficial programs, leading to better support and improved outcomes for those in need.
- On April 20, 2025, Green Giving was added to the simplified digital enrollment experience. In just the first hour, six customers enrolled—matching the total enrollments agencies achieved in the previous six weeks.
    - Since then, the Company has enrolled 515 low-income customers digitally, while agencies have enrolled 10.

      This contrast highlights the urgent need to streamline enrollment and eliminate administrative barriers. Modernizing the Company's approach is essential to better serve its customers and maximize program impact.

- 87% of users that completed the survey reported that it was extremely easy[2], or easy to complete the experience.
- 56% of users that completed the survey reported that they felt the offerings provided to them were extremely personalized or very personalized to them.
- By implementing the tool, the Company has reduced the need to send approximately 300,000 emails to promote individual products to reach enrollment goals, streamlining the Company's outreach efforts and maximizing efficiency.
- The tool has captured over 3,000 leads for EWR programs[3]. The tool's ability to capture leads organically indicates a user-friendly and effective design, making it easier for customers to navigate and enroll in programs.

These results affirm that the tool is immediately delivering on its intended purpose: reducing enrollment barriers, increasing program visibility, and helping LMI customers more easily access the support they need. Continued monitoring and feedback collection will allow the Company to further refine the tool and expand its impact in the months ahead.

**Q. On page 19, lines 5 through 10, Staff witness Klocke states "A main reason Staff does not support this project is because Staff does not believe this project will do anything to fix or prevent the root causes of customers either in or on the brink of crisis. The LMI project will not reduce customers' energy burden, even if they are able to utilize a payment plan, select their due date, or anything else – these solutions are mere band aids to the larger root problem of energy unaffordability." Does the Company agree with this assessment?**

[2] Based on a rating scale the rating scale includes:
Extremely Easy
Very Easy
Moderately Easy
Slightly Easy
Not Easy at all

[3] The tool captures leads to send to CLEAR, to then contact customers to schedule Home Energy Analysis appointments.

A. No. While Staff witness Klocke says that the LMI project does not address the root causes of energy unaffordability and merely offers band-aid solutions, it is important to recognize the immediate and tangible benefits this project provides to LMI customers. The LMI project is designed to provide crucial immediate relief and support to those who are currently facing significant energy affordability challenges.

By simplifying enrollment processes, proactively communicating with customers, and integrating and improving existing assistance programs, the project ensures that customers can access the support they need without unnecessary hurdles. This immediate support can help prevent service disconnections, reduce energy burdens, and improve household stability, which are essential outcomes given the current economic realities. This project serves as a necessary step in building a more comprehensive support system for LMI customers. The Company's broader strategy encompasses several key initiatives aimed at addressing both immediate needs and long-term challenges.

**Q. On page 15, and page 16, lines 1 through 16, Staff witness Klocke references the LMI project's Simplified Enrollment goal, stating "Staff frankly does not understand why this information regarding enrollment is not already available to customers and is unclear why the Company needs so much money to allow customers to enroll in applicable programs." How does the Company respond?**

A. While enrollment information is available on the website and accessible to all customers (and non-customers), it is not presented in a way that is easily navigable or actionable for a specific subset of customers: those in need of assistance. Staff have stated that the tool should be available to all customers, and it is indeed accessible to all customers who are authenticated on the Company's website. Data shows that 8% of customers who have self-

identified within this LMI enrollment flow are market rate customers, falling outside of the LMI eligibility parameters. This demonstrates that these customers are still able to access the flow and enroll in offerings for which they are eligible. The flow does not limit access; it streamlines enrollment, making it easier for customers to understand what programs they are eligible for based on their customer profile.

Staff witness Klocke points out that links to assistance programs exist on the Company's website on page 19, lines 13–14, but that information shared via a static website versus interactive web tool significantly limits its effectiveness and often adds to the burden of figuring out what to do with that information.

For example, recommendations from State collaborative workgroups supported by primary customer research, including surveys and usability testing, show that the current assistance enrollment experience is burdensome, fragmented, and often overwhelming. Research findings include:

- "It takes about 30 minutes, filling out nine forms to begin to sign up for State benefits, assuming steady internet access, device compatibility, and printing/scanning ability"[4];
- "25% of LMI customers indicated say they are not interested in learning about EE (Energy Efficiency) programs because they do not have time to participate[5]"; and
- 51% of LMI customers agree with the statement "I never seem to have enough time to get things done[6]."

Making information available on the website does nothing to address the root cause of some of these difficulties.

[4] From a Consumers Energy customer interview
[5] From third party research conducted by Bellomy
[6] From third party research conducted by Bellomy

The project's simplified enrollment goal is not to duplicate content—it is to deliver a centralized, web and mobile-friendly tool that provides step-by-step guidance based on a customer's individual circumstances. It matches customers only with programs for which they are eligible, explains what is required for enrollment, and allows them to share their information once, rather than repeatedly. The Company has supported and acted on simplifying assistance enrollment in direct response to the complexity of government bill assistance approval flows. With various levels of assistance, programming options, and requirements/eligibility, customers can find themselves lost in the details. Within the LMI project, the focus is on individual opportunity and not a one-size-fits-all information download. This level of customization, guided by real customer insights, goes far beyond a standard web feature or program list. The tool ensures that customers are not just informed—but effectively guided—through the enrollment process with clarity and ease.

The LMI project goes beyond making information available to customers. The funding request reflects the work required to design, build, test, and deploy a digital tool with a personalized, human-centered interface that addresses complex processes and long-standing barriers for LMI customers. Therefore, while the Company agrees that the information should be accessible on the website, the development and deployment of this tool is a distinct, necessary investment that fills a critical gap in the Company's current service model that goes beyond simply making the information available. It is a reasonable and prudent initiative that directly supports equity and ease of access for the customers who need it most.

**Q. On page 16, beginning at line 21 through page 17, line 4, Staff witness Klocke stresses that assistance information should be accessible to all customers, and in doing so states (page 17, lines 2 through 6) that "Staff is not convinced that the Company's definition of customers in crisis adequately captures all those customers who could end up in crisis..." How does the Company respond?**

A. As noted by Ms. Klocke on page 16, lines 17 through 19, "In an uncertain economic climate, virtually anyone could be in crisis with the loss of a job, unexpected bill, medical emergency, etc." Under the LMI project, the Company has identified low-income customers as "being in crisis" –and moderate-income customers as "one crisis away" from being in crisis. Examples of "one crisis away" include situations such as a missed paycheck or job loss. The scope of the LMI Customer Support Enhancement Project includes exploring ways to support customers who do not currently qualify for low-income assistance but still face significant financial challenges including emergency or unexpected challenges as noted by Staff witness Klocke. In alignment with Ms. Klocke's comments, the intent of this project is to expand support for customers beyond the traditional low-income definition to also include moderate income customers at risk of financial hardship and all customers that may be seeking opportunities to lower their energy bills.

**Q. On page 16, lines 6-12, Staff witness Klocke states another core function of the LMI project--Proactive Communications and Program Awareness is unneeded because the Company already conducts outreach. Does the Company agree?**

A. No. On page 16, lines 11 through 12, Staff witness Klocke states that the $400,000 cost of this targeted LMI outreach is unnecessary given that "Residential customers, regardless of income, are given outreach via direct mail and email for information about EWR, demand

response, and Renewable Energy Programs." Additionally, Ms. Klocke states on page 17, line 4 "believes all customer classes – not just those identified as low-to-moderate income – should have access to the information the LMI project provides"

The Company disagrees with the notion that targeted outreach is unnecessary. All customers will continue to receive information about available programs and have access to the LMI tool, as discussed above. However, the LMI project's Proactive Communications and Program Awareness initiatives are designed to complement broad marketing efforts by applying focused awareness tactics specifically tailored to the unique needs of LMI customers who face unique and well-documented barriers to engagement.

This is a "yes, and" approach—not an either/or. It ensures the Company continues to engage the full customer base while also delivering more effective, personalized communication to those who are most in need. The foundation of the communications targeted to the LMI customer population is based on identified risk and an assessment thereof based on (1) account and behavior data and (2) information gathered through the self-attestation a customer provides when accessing the larger LMI project flow--that may indicate or serve as evidence that a customer may be struggling now or will be in the near future. This data paired with LMI Mindset Map included as Exhibit A-129 (JRB-4) insights inform proactive communication strategies. There is a planned methodology behind the targeted communications. Consequently, the Company is enabled to anticipate needs, align with customer motivations and preferences, and drive stronger engagement with better outcomes.

**Q. On page 17, starting at line 12, Staff witness Klocke discusses another stated goal of the LMI project, New and Improved LMI Offerings, by which the "Staff is perplexed why a new program such as this one would need such expensive 'improvements' already." How does the Company respond?**

A. The Company believes it will take a significant, upfront investment to create an infrastructure, both programming and technological, to support the goals of new and responsive LMI offerings, as well as the LMI project as a whole. Part of the infrastructure required is assessing how current programs fit together, what gaps exist between current and potential services, and how to tie everything together for the most efficiency for the overall customer experience.

**Q. On page 18, starting at line 9, Staff witness Klocke discusses the final stated goal of the LMI project—Continuous Improvement—where she states, "Again, it appears the cost requests and the overall LMI project itself is too premature to be deemed reasonable and prudent." Why is the proposed LMI project a reasonable and prudent investment for the Company and its customers?**

A. This project's goal of Continuous Improvement speaks to the fact that it is not a one-time deployment; it is an evolving solution, especially in this startup phase. The Company is actively monitoring usage patterns and collecting feedback to enhance the tool's performance and expand its capabilities. The lessons being captured today will further strengthen the tool's effectiveness and enable it to reach a broader segment of the customer population over time.

The proposed LMI project is a reasonable and prudent investment because it is directly informed by robust, customer-centered research and is designed to address

well-documented barriers that prevent LMI customers from accessing the assistance they need. The Company initiated primary and secondary research with over 2,000 low-income customers to better understand LMI customers and to identify barriers to awareness about assistance options and participation in utility programs. This research included surveys, interviews, customer panels, and usability tests, and uncovered two primary barriers: a general lack of awareness about available programs and a perception that the enrollment process is overly complex.

In response to these findings, the LMI project is tailored to reduce these specific barriers by improving communication, simplifying enrollment processes, and streamlining customer experience. By doing so, the project aims to improve access to critical assistance programs and ensure more equitable outcomes for vulnerable customer groups. The design of the project is evidence-based, targeted, and aligned with the Company's obligation to serve all customers effectively, particularly those most in need. For these reasons, the investment is both reasonable and prudent, as it addresses a demonstrated customer need with appropriately scoped and strategic solutions.

**Q. Please explain why the overall, upfront investment in the LMI project is justified, and how that investment ultimately provides long-term benefits, including utility bill reductions, for customers?**

A. The upfront investment in the LMI Customer Support Enhancement Project is both necessary and justified because it lays the foundation for long-term, sustainable benefits that directly improve customer outcomes and reduce energy burdens over time. This investment supports the development, deployment, and refinement of a digital tool that

helps customers more easily identify and enroll in assistance programs for which they are eligible—many of which provide direct utility bill savings.

Historically, LMI customers face multiple barriers to accessing support: limited awareness, confusion about eligibility, and difficulty navigating enrollment processes. By removing these barriers through a streamlined, automated solution, the program increases uptake in bill assistance and energy efficiency offerings—leading to tangible, recurring reductions in monthly utility bills for eligible customers.

For example, customers who successfully enroll in assistance programs may receive monthly credits, arrearage forgiveness, or energy efficiency upgrades that lower usage, which translates to lower bills. By making it easier to access these benefits, the program not only delivers immediate relief but also supports long-term household stability and improved payment behavior, which benefits the broader customer base by reducing uncollectible expenses. Thus, while the initial costs are concentrated at the front end, the return on investment is realized over time. This is an informed, customer-centric investment that aligns with the Company's and goals of affordability, equity, and service quality.

**Q. What would be the impact of disallowing the LMI Customer Support Enhancement Project?**

A. Disallowing this project would have significant and immediate negative consequences, particularly for the Company's most vulnerable customers. The LMI digital tool was developed to address persistent challenges—such as lack of awareness, confusion about eligibility, and difficulty navigating the application process. These challenges disproportionately affect low-income households, who are often already struggling with

affordability and energy insecurity. A disallowance of this project means effectively deferring meaningful relief and continuing to rely on fragmented systems that are not meeting the needs of these customers. Moreover, this project benefits all ratepayers by promoting broader enrollment in assistance and energy efficiency programs, which in turn can reduce bills, improve payment behavior, and ultimately lower the level of uncollectibles carried by the utility. In sum, this is a proven, customer-informed solution ready for deployment. Disallowing the project unnecessarily extends hardship for low-income customers and undermines the Company's commitment to equitable access and affordability.

**Staff Witness Klocke Regarding Click To Chat, Web Chat AI, And Self-Service Mobile App**

**Q. Staff witness Klocke also recommends historical, bridge, and test year disallowances for several Customer-related IT Enhancement projects. Please discuss.**

A. Staff witness Klocke's proposed disallowances include $45,683 in capital for the historic year ended December 31, 2023, as well as $2,958 in capital expenditures for the bridge year period ended December 31, 2024 for Click to Chat (Staff witness Klocke Direct Testimony, page 5, lines 20 through 23, through page 6, lines 1 and 2); proposed disallowances for Web Chat AI include $180,565 in capital expenditures, and $14,929 in O&M for the test year ending October 31, 2026 (Staff witness Klock Direct Testimony, page 8, lines 16 through 18); and finally, proposed disallowances for Enhancements to the Company's Mobile App include a decrease of $61,562 in historical capital, $274,116 in capital costs for the year ended December 31, 2024, $598,472 in capital costs for the year ending December 31, 2025, and $550,025 in capital costs and $6,510 in O&M costs for the

projected test year ending October 31, 2026 (Staff witness Klocke Direct Testimony, page 10, lines 11 through 14).

**Q. Does the Company, in general, agree with Staff witness Klocke's reasoning?**

A. No. All three digital tools that Staff witness Klocke puts forth for disallowance are: (1) based on industry research that supported customer desire for chat-based applications; (2) currently in existence and in use by customers; and (3) consequently require updating and maintenance. For those projects previously supported in rate cases Staff have not pointed to any circumstances that have emerged since the Commission issued these orders that should cause them to revisit.

The Company has previously cited JD Powers findings regarding chat tools, including one that found that live chat has become the leading digital contact method for online customers with 42% of customers preferring live chat compared to just 23% for email. The development and maintenance of these tools are not driven by utility preference but are a direct response to the expressed needs and expectations of the customers the Company serves. Furthermore, peer institutions have both similar tools and similar restrictions to customer assistance hours (see Help Center | DTE Energy[7] and Contact Us | AEP Energy[8]), setting Consumers Energy on equal footing with its peers, implementing best practices by providing customers with channels of choice.

In providing different channels of communication, it becomes a necessary obligation for the Company to update and maintain the tools customers prefer to use. From the emerging Web Chat AI tool to the Click to Chat tool available to business customers and the established and popular Mobile App, investments into these enhancements ensure

[7] https://www.dteenergy.com/us/en/quicklinks/help-center.html
[8] https://www.aepenergy.com/contact-us/#:~:text=Chat,am%20%E2%80%93%207%3A00%20pm.

these tools work as requested or expected. To that end the associated investment should be considered reasonable and prudent.

**Q. Does the Company agree with Staff witness Klocke's reasoning for recommending the disallowances for Click to Chat.**

A. No. Starting on page 5, line 20, Staff witness Klocke states Staff's points against the Click to Chat project—including finding "the project does not offer any new technology or features that are innovative, nor does it represent any cost savings" (page 6, lines 7 to 8).

She further restates on page 7 lines 6 through 12 that "Staff also has concerns that just 314 uses of Click to Chat have been reported by the Company's agents. (Staff Exhibit S-11.1.) For a project that has now been available for over three years, usage is very low. In that same audit response, the Company stated that it currently has 'no tracking regarding how many of their [customers'] problems/issues were fully resolved using this feature.' (Staff Exhibit S-11.1.) Staff finds it troubling that the Company is not tracking the results of this project in an effort to measure its success."

The goal of Click to Chat was not to only reduce call center costs, but to offer customers another channel through which to reach the Company and potentially self-serve.

Additionally, Staff continues to support only the implementation of IT applications that are considered valuable because of associated cost savings. This fails to consider that both customer preference and accessibility have value of their own. On page 7, lines 13 to 14, Staff witness Klocke states that "any major problems will still require CSR intervention" but fails to recognize: (1) Click to Chat was never envisioned or intended to solve urgent customer inquiries, and (2) that both time and costs savings might be realized

in the disposition of common or simple issues that customers may solve via chat without any involvement from the Customer Service personnel.

The administrative law judge ("ALJ"), and ultimately the Commission, recommended recovery of historical costs for Click to Chat in Case No. U-21585 (See MPSC Case NO. U-21585, March 21, 2025 Order, page 185 "The ALJ agreed with Consumers that, although the Click to Chat function does not save money, it contributes to the provision of utility service").

**Q. Does the Company agree Staff witness Klocke that usage of the Click to Chat tool is low?**

A. No. On page 7, line 6, Staff witness Klocke cites the number of completed Click to Chat interactions as 314 and then states that "For a project that has now been available for over three years, usage is very low." However, the Click to Chat project implementation had been delayed until late October 2023. Consequently, the project has been available for approximately 18 months, not three years, effectively doubling the usage statistics. When added to the fact that Click to Chat was initially available as a non-market soft launch to business customers, Staff witness Klocke has understated the number of customer interactions with the tool and underestimated the potential of a relatively new channel.

**Q. Does the Company agree with Staff witness Klocke's reasoning for recommending the disallowances for Web Chat AI Enhancements. Please discuss.**

A. No. Staff witness Klocke states on page 9, line 5that Staff finds Web Chat AI "redundant and not worth the cost." And "In essence, the Web Chat will simply be aggregating information that is already available to customers on the Company's website." (page 9, lines 11-12). The Company maintains that chat functionality is a customer channel of

choice, and as such should be supported, maintained, and updated as necessary. Additionally, Web Chat AI is in the early stages of enhancement and consequently cost savings are unquantified at this time. The Company remains committed to the tool as an alternative channel of interaction with the Company. Not every customer has an issue or question that rises to the level of calling a service center and the Web Chat AI tool will provide relevant information in an instant and the customer may interact according to their situation.

**Q. Please discuss Staff witness Klocke's reasoning for recommending the disallowances for Mobile App Enhancements.**

A. Starting at page 11, line 6, Ms. Klocke states that Staff is against the Company's Mobile Application funding—and in this case that includes the funding for enhancements—recommending a decrease of $61,562 in historical capital costs for the year ended December 31, 2023, $274,116 in capital costs for the year ended December 31, 2024, $598,472 in capital costs for the year ending December 31, 2025, and $550,025 in capital costs and $6,510 in O&M costs for the projected test year ending October 31, 2026 (page 11 , lines 11 through 14).

She states on page 11, lines 21 through 23, and page 12, lines 1 through 4 that "Staff's position regarding the Mobile App has remained the same in every case it has been presented in, starting with Case Nos. U-20697, U-20963, U-21224, U 21389, electric cases, and Case Nos. U-21148, U-21308, and U-21490, gas cases. In each of those cases, Staff's position is that the Mobile App represents functionality that is duplicative of the Company's website and is therefore unnecessary and its over $10 million total costs should

not be passed on to ratepayers." Further, page 12, lines 7 and 8, "the Company has never conclusively proven a need for such an application or customers' interest in it."

**Q. Does the Company agree with this assessment?**

A. No. The Company has consistently supported the development and launch of its Mobile Application for several reasons, including those outlined below. It is for these reasons that the Mobile App enhancement dollars should be allowed.

1. The Commission took no position on the Mobile App in Case No. U-21224, which was settled. However, the Commission expressly approved the Mobile App project on its merits in Case No. U-21389 finding "The Commission agrees with the company's arguments that, while there may be some redundancy in the functions of the app and the website, there is value in offering varying communication channels to meet customer needs. As pointed out by Consumers in its exceptions, it could be argued that there is redundancy between the functions of call centers and the company's website as both are avenues to receive customer payment. As technologies and customer preferences evolve, the Commission finds that duly supported, reasonable, and prudent expenditures to meet those preferences are appropriate for recovery."(MPSC Case No U-21389, March 1, 2024 Order, page 83.);

2. Since the app's launch, there have been almost 1.5 million downloads and the Company has seen the popularity of the app continually increase, with a current share of digital traffic at over 28%, and now exceeding Desktop Web use (App use of 5.3 million sessions vs Desktop use of 4.6 million sessions for 2025 YTD);

3. The Mobile App is not a carbon copy of website functionality, nor was it conceived in this way. As the Company has stated several times, the Mobile App has separate functionality and has the added benefit of not needing a web interface to interact with the Company. The Mobile App was developed to provide a streamlined experience for customers, allowing them to complete common interactions quickly and efficiently on their phones, with features like simple login and direct access.

4. The Mobile App continues to serve as a reliable platform during potential website downtimes, ensuring that customers can still complete routine transactions like bill payments.

5. As shown by adoption and use statistics above, customers prefer to perform more complex interactions in the mobile app and additional functionality should be expanded in response.

These points highlight the recognized functionality and growing popularity of the Mobile App amongst Consumers Energy's customers for an array of their interaction needs. The related enhancement dollars should be allowed to support and enrich the Mobile App experience.

**Website Redesign**

**Q. Staff witness Klocke often mentions disallowances in conjunction with a desire to see the Company's website update realized saying regarding Web Chat AI on page 9, Lines 12-15 "Staff has and does support the Company's planned website redesign and feels it would be a much better use of Company resources – and ratepayer money – to update the website to make any general, frequently asked questions easily found."). and includes this language in relation to the LMI project, the Mobile App, and Enhancements to Company chat functionality. Please respond to the suggestion that the website is the central technology vehicle for the Company.**

A. The Company agrees with Staff witness Klocke that a current and robust website is beneficial to an organization that provides a large volume and wide variety of information and resources to their customer base. The Company has requested and received support for its website redesign (Case No. U-21308, Case No. U-21224, and Case No. U-21490) and has been delayed in fully realizing its stated plans (please see Company witness Stacy H. Baker's rebuttal testimony for information on overall website redesign progress). However, in relation to the Mobile App and chat functions, the Company has stated and reiterates here that these tools are not intended to have all the functionality of the website, nor are they intended to replace the website or other customer channels. The customer IT projects

referenced by Staff witness Klocke provide support for specific yet complex interactions that are not necessary in all channels of communication.

The Company remains committed to updating its website to provide accurate and up-to-date information for all of its customers. As the Company works through the IT solutions in progress to achieve this goal, it also remains committed to growing channels utilized by customers.

**Attorney General O&M Disallowance for DCO and Analytics and Outreach**

**Q. Does the Company agree with Attorney General witness Coppola's recommendation, starting at page 174, line 12, to page 175, line 15, to disallow $2,325,000 from Analytics and Outreach related O&M.**

A. No. The Company disagrees with Attorney General witness Coppola's recommendation to disallow $2,325,000 in Analytics and Outreach related O&M. While Attorney General witness Coppola notes (page 174, lines 19 to 20) that the Company responded to a discovery request including historical and forecasted staffing, work activities, and associated outcomes he then dismisses the information provided to be of insufficient clarity.

Starting at line 3 on page 175, Attorney General witness Coppola shares the Company's personnel numbers, but continues to state that when it came to accurate responses regarding customer interactions, "From the response, it is not clear what customer interactions entail, why there are so few, and why they decline from 2022 and stay the same between 2024 and the projected test year when the number of employees and contractors in this function increases." The Company provided overviews of the Analytics

and Outreach department's responsibilities and activities as seen in Exhibit AG-60, page 1, as well as work units, headcounts, and budgets.

The Analytics and Outreach group serves a vital function for incorporating customer feedback and data into the Company's operations, which directly contributes to improving customer experience. This allows the company to use its resources more efficiently, target communications to precise customer segments, and select programs that are most likely to provide customer value.

Program priorities include:

- All MPSC reporting – providing reporting metrics and data as required or requested by internal stakeholders
- Estimated Time of Restoration ("ETR" – utilizing Machine Learning in real time, to provide an ETR when a customer loses power, on blue sky days through catastrophic storms)
- Customer Experience Index – supporting the Company's top level goal of consolidation of all live and automated phone calls, app and web traffic, and customer experience surveys across all channels
- Data Automation – centralizing all data outputs from the dozens of source systems and properly storing and maintaining in a centralized resource
- Data Quality – ensuring accurate Customer information for address, email, phone numbers, etc. - improving communication accuracy
- Data Visualization – the execution of all metrics tracked by both Customer Operations and Customer Experience
- Problem Solving – deep dive analysis into the most granular data to support the improvement of customer impacting metrics

**Q. Does the Company agree with Attorney General witness Coppola's recommendation to disallow $536,000 or half of the original $1,072,000 request from O&M related to DCO.**

A. No. Starting on page 176, lines 5 through 17, Mr. Coppola argues there is a lack of information about who and what comprise the DCO organization.

Mr. Coppola states "it is not clear why most of the system functions already developed would require repeat work using the same number of employees and contractors every year. The general description of accomplishments does not make a compelling case that significant value is being generated. There is insufficient support to justify the number of resources assigned to this function. The evidence is inadequate, and the expense level remains unsupported." See Direct testimony of Mr. Coppola at page 176, line 19, through page 177, lines 1 through 5.

The DCO manages a channel that gets more than 45 million customer interactions annually and provides customers with a valuable self-service tool when managing their energy consumption. The teams' services are particularly valuable when viewing 2024 statistics for the Company's website and mobile application, including 15.7 million views related to checking billing status, 13.8 million related to payments via web or app, and 4.5 million views to view outage status. The DCO team keeps the website and mobile app running, accessible for and responsive to Consumers Energy customers as a well-used channel of choice. The DCO team is critical to the success of the company's objective to digitize more transactions to better serve customers on the website, which is a more cost-effective means of serving customers than other channels.

Additionally, as evidenced in Exhibit AG-60, page 2, overall costs for DCO O&M have been relatively decreasing as the group finds efficiencies and constancy in the technologies it supports.

**Attorney General on Affordability**

**Q. On pages 16 and 17, lines 4 through 9 and 2 through 10, respectively, of his direct testimony, witness Coppola states that capital spending will pose a significant burden on residential customers and business bills. What options does the Company have available to assist customers?**

A. Company witness Neal P. Dreisig's rebuttal testimony discusses the economic effect of capital spending on both residential and business bills, including the Company's efforts to balance the cost of reliability and safety with rates. In his testimony, witness Dreisig references both the Company's energy-efficiency programs and its LMI assistance Consumers Affordable Resource of Energy ("CARE") Program as examples of the Company's commitment to providing customers with energy assistance.

**Q. Please provide details about how the Company's energy efficiency and CARE program provide assistance to ratepayers.**

A. The Company's CARE program is designed to assist income-qualified customers in managing their energy use and bills more effectively. CARE provides customers with bill assistance via a 24-month program that includes a fixed monthly bill—offering a consistent, reduced monthly payment plan that makes budgeting for energy expenses more manageable. As customers make regular, on-time payments, existing past due balance will be forgiven. Customers may also be provided with no-cost, in-home energy efficiency upgrades to help reduce energy costs

**Q. Does Consumers Energy offer other assistance programs for qualifying customers?**

A. Yes. Consumers Energy offers assistance via several additional programs, including State and Local programs. Details may be found at Payment Plans & Assistance | Consumers Energy.[9] Additionally, investment in the LMI project will allow the Company to better assist customers enroll in programs.

**CUB Witness Bunch's Affordability and Uncollectable Discussion**

**Q. Starting on page 4 of his testimony, CUB witness Bunch also voices concern about the Company's proposed rate increase, citing its effect on affordability for low-income and senior customers. Starting on page 7, lines 3 through 4, CUB witness Bunch provides the source for calculations that follow. What is that source?**

A. Mr. Bunch is referencing data from the Company's quarterly reports filed in the docket for Case No. U-18120 the Rule 51 report), a snapshot of which is in Figure 1 below.

Figure 1

| Rule 51 Trending | Jan-22 | Feb-22 | Mar-22 | Apr-22 | May-22 | Jun-22 | Jul-22 | Aug-22 | Sep-22 | Oct-22 | Nov-22 |
|---|---|---|---|---|---|---|---|---|---|---|---|
| Customer Service | | | | | | | | | | | |
| Total customer contacts (Res and Non-Res) | 716,767 | 704,762 | 847,519 | 764,817 | 741,068 | 842,070 | 836,679 | 1,102,010 | 779,668 | 764,582 | 881,079 |
| Total customer complaints | 6,902 | 6,773 | 8,241 | 7,120 | 6,601 | 7,092 | 6,798 | 7,635 | 7,706 | 6,865 | 6,173 |
| a. Billing | 1,909 | 1,766 | 2,025 | 1,702 | 1,624 | 1,633 | 1,759 | 1,814 | 1,851 | 2,011 | 1,585 |
| b. Service | 701 | 665 | 918 | 853 | 814 | 966 | 930 | 1,209 | 995 | 903 | 928 |
| c. Credit and Collection | 3,831 | 3,887 | 4,773 | 4,173 | 3,791 | 4,114 | 3,733 | 4,157 | 4,478 | 3,583 | 3,287 |
| d. Other | 443 | 445 | 504 | 392 | 372 | 379 | 364 | 438 | 364 | 354 | 362 |
| Freeform area | 18 | 10 | 21 | 19 | 12 | 15 | 12 | 17 | 18 | 14 | 11 |
| Customer Payment Performance | | | | | | | | | | | |
| Number of customers paid by the due date | 2,763,645 | 2,725,736 | 2,739,286 | 2,756,938 | 2,715,413 | 2,731,921 | 2,744,007 | 2,736,725 | 2,745,207 | 2,748,898 | 2,764,311 |
| Number of customers delinquent 31-60 days or more | 83,193 | 82,080 | 82,371 | 86,369 | 94,906 | 84,652 | 95,991 | 78,187 | 91,310 | 92,197 | 87,698 |
| Number of customers delinquent 61-90 days or more | 42,392 | 40,093 | 31,935 | 37,120 | 42,730 | 46,023 | 51,012 | 50,595 | 39,214 | 48,793 | 48,138 |
| Number of customers delinquent 91 days or more | 70,694 | 68,233 | 63,849 | 54,117 | 59,186 | 62,876 | 69,453 | 80,876 | 80,730 | 78,122 | 79,799 |
| Payment Plans and Settlements | | | | | | | | | | | |

**Q. Does the Company dispute CUB witness Bunch's findings using this data?**

A. Yes.

[9] https://www.consumersenergy.com/residential/account-and-billing/billing-and-payment/payment-assistance

**Q. Please explain.**

A. For example, on page 7, lines 4 through 5, CUB witness Bunch uses this data to support his assertion that delinquent accounts are growing significantly.

**Q. Is this an accurate statement?**

A. CUB witness Bunch is correct when he states, "The number of accounts that are 90+ days in arrears has been growing" (when referring to years 2022-2024). However, the significance of this growth is open to interpretation due to the potential exaggeration from the chart's scaling. For example, if the same dataset referenced on page 7, lines 3 and 4, can be expanded to show the period of 2020-2024, customer accounts in arrears did increase (Figure 2), but also saw several decreases. Additionally, over the same 2020-2024 timeframe, correlated dollar amounts arrearage decreased (Figure 3).

**Q. Why does this matter?**

A. By selecting a specific timeframe on which to focus, CUB witness Bunch provides only the context of the data and no social, political, or economic context for which there might logically be a drop or a surge in arrears. He also fails to offer policy implications, either macro or micro (e.g. the way arrears were reported or accounted for), context.

Figure 2

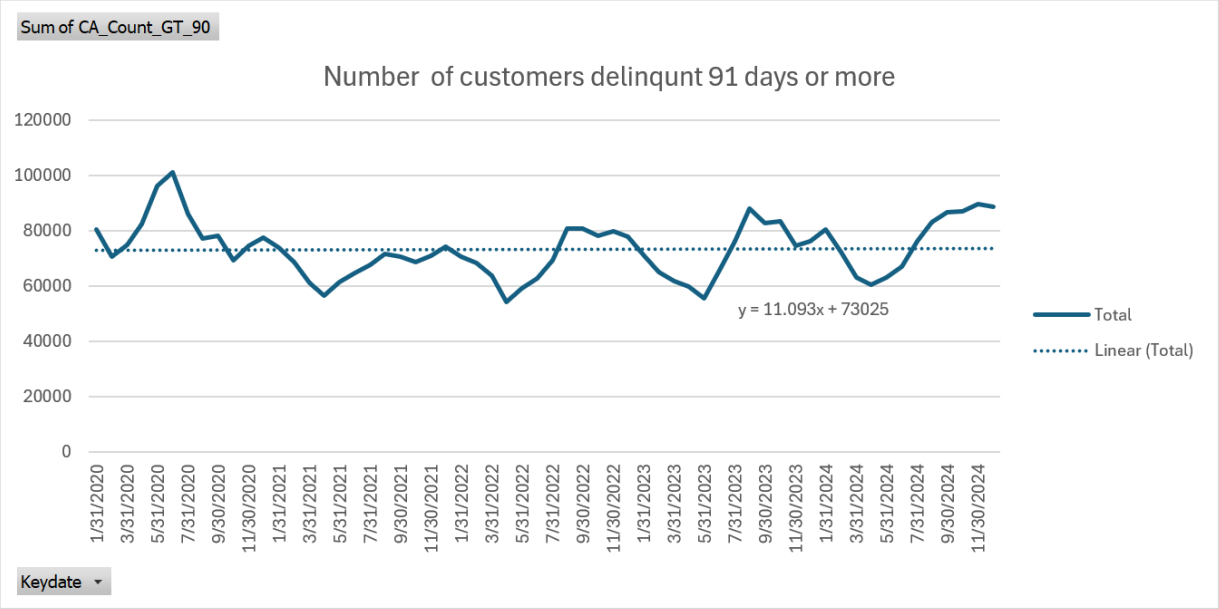
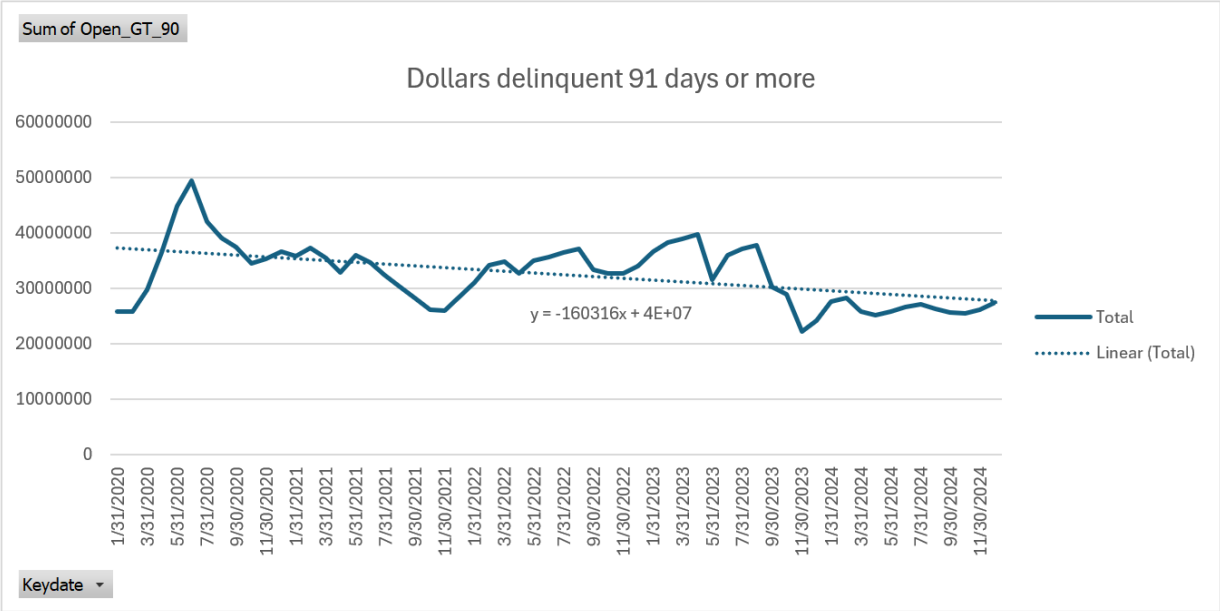



Figure 3



**Q. On page 7, lines 9 through 10, CUB witness Bunch indicates "Long-term delinquencies have grown by about 25% over the past three years." Is this accurate?**

A. Mr. Bunch may be referring to the percent change in customer count in the Over 90 bucket, from Jan 2022 to Dec 2024: (88,577 – 70,694) / 70,694 = +25%. in Figure 1. Though this is the accurate percent change in customer count, a comparison of a data point from one month (January) to the data point from a different month (December), may not be comparable since arrears is cyclical. Also, it's worth noting that while customer count did trend up, dollars in the 91+ days-past-due bucket trended down over the time period highlighted by CUB witness Bunch.

**Q. On page 8, line 5, Mr. Bunch states "From 2021 to 2023, residential uncollectible expenses increased 53.7%." Is this accurate?**

A. The date on page 8, line 6, and on which CUB witness Bunch bases his statement is accurate and was cited from Company-provided data.

**Q. Starting on page 8, line 10, and continuing through page 10, line 6, CUB witness Bunch discusses the Company's rate impact in conjunction with inflation and spend. Does the Company agree with his testimony?**

A. Company witness Dreisig discusses the Company's position on spending and rates and the rate of inflation in his rebuttal testimony.

**Q. On page 10, starting at line 7 and continuing through page 8, after noting the assistance levels the Company provides, CUB witness Bunch concludes "I find that Consumers' customers received almost $24 million (or 57%) more in various forms of assistance in 2023 than in 2022. Yet the number of customers who are more than three months behind, and the dollar value of residential uncollectibles, are both surging." How does the Company respond?**

A. The Company recognizes that many of its customers either cannot pay or cannot pay the totality of an energy bill. As previously noted, Company witness Dreisig discusses the efforts the Company has taken to keep rates in line with inflation and the Company's efforts to balance the cost of reliability and safety with rates. In addition to these efforts, the Company has provided increased assistance available to numerous customers but there are other factors that may contribute to arrears or uncollectables. CUB witness Bunch's statements provide one factor but the issues are multi-factored.

**Q. CUB witness Bunch questions (page 11, lines 9 and 10) why increased assistance has not affected and not offset the observed increase in delinquent accounts and uncollectibles and reasons that it is because the Company is not reaching, or reaching only a subset, of those who are in most need. How does the Company respond?**

A. The Company is actively trying to reach both those who are currently delinquent or in arrears and those who might be approaching that status through the LMI Customer Support Enhancement Project.

**MEC Witness Napolean Regarding the EWR Programs**

**Q. MEC witness Napolean states (page 18, lines 6-11) that the Company's EWR program savings and design are relevant in the present case, since they inform Consumers Energy's investment plan. Further, she states that the focus of the gas efficiency program should be on electrification measures as well as weatherization and building envelope measures. Does the Company agree?**

A. No. Please reference Company witness Neal P. Dreisig's rebuttal testimony for a discussion on gas efficiency as related to electrification and declining gas consumption. The Company's next EWR plan (MPSC Case No. U-21680) will be filed in August 2025 and its reconciliation MPSC Case No. U-21671 Is currently pending before the Commission and by statute, these programs are designed and reconciled outside of general rate proceedings, and the proper venue to make suggestions on EWR program design would be in a reconciliation or plan filing.

**CUB Witness Denzler's Disallowance of COST Projected O&M Savings**

**Q. Starting on page 27, line 3, of his testimony, CUB witness Denzler supports the COST project, including supporting the project's objective of tracking customer orders in real time and saving costs associated with incoming calls for information and outgoing truck rolls based on erroneous or out-of-date information. However, he recommends the Company's projected O&M savings be disallowed in the present case, and as a counter to the Company's discovery response that these savings are estimated and not included in present Company projects. Mr. Denzler states that all projected costs are estimated and therefore able to be reduced accordingly. How does the Company respond?**

A. The Company agrees the COST project will result in significant savings, but it is important to note that the project is in the early stages, and that the savings are in fact estimated as part of the related cost/benefit analysis, and subsequently have not been accounted for in Operations other than IT implementation, and consequently should not be pulled from the present case.

The Company's test year forecast for the COST project should be approved, excluding O&M savings that cannot be realized within the test year. During this period, the Company will complete the project, without yet benefiting from the anticipated savings. It is unreasonable for CUB witness Denzler to assume immediate realization of savings upon project completion. Approval of the project's spending should be based on the understanding that O&M savings will be evident in the Company's subsequent rate case.

While Mr. Denzler's focus is on the financial aspects, the benefits of the project extend beyond mere cost savings. The project aims to enhance customer interaction and streamline Company processes, which are not fully captured in a traditional cost/benefit analysis. The reduction in contact center calls and improved scheduling efficiency are expected to lead to better resource utilization and customer satisfaction.

**Q. Does this conclude your rebuttal testimony?**

A. Yes.

MR. RUSZKIEWICZ: The Company's next witness is Amy M. Conrad. And based on the stipulation of the parties, the Company moves to bind in the testimony of Amy M. Conrad, which consists of direct testimony of a cover page, plus 38 pages of prefiled testimony. Also, Ms. Conrad had rebuttal testimony consisting of a cover page and 10 pages of prefiled testimony.

The Company also moves to admit Ms. Conrad's exhibits, which consist of A-39, A-40, and Exhibit A-41, and then also Exhibit A-132.

JUDGE VARCHETTI: All right. Are there any objections to the admission of Ms. Conrad's direct or rebuttal testimony or any of the associated exhibits?

Hearing none, then, the testimony is bound into the record, and the exhibits are admitted.

MR. RUSZKIEWICZ: Thank you, Your Honor.

(Direct and Rebuttal Testimony bound in)

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

| | | |
|---|---|---|
| In the matter of the application of<br>**CONSUMERS ENERGY COMPANY**<br>for authority to increase its rates for the<br>distribution of natural gas and for other relief. | )<br>)<br>)<br>)<br>) | Case No. U-21806 |

**DIRECT TESTIMONY**

**OF**

**AMY M. CONRAD**

**ON BEHALF OF**

**CONSUMERS ENERGY COMPANY**

December 2024

**Q. Please state your name and business address.**

A. My name is Amy M. Conrad, and my business address is One Energy Plaza, Jackson, Michigan 49201.

**Q. In what capacity are you employed?**

A. I am employed as the Director of Compensation Operations for Consumers Energy Company ("Consumers Energy" or the "Company").

**Q. What is your educational background?**

A. I graduated from Central Michigan University in 1999 with a Bachelor of Science Degree in Business Administration with a major in Accounting. In addition, I am designated as a Certified Compensation Professional and Certified Executive Compensation Professional by WorldatWork and a Certified Public Accountant by the Michigan Association of Certified Public Accountants. WorldatWork is an international professional organization focused on human resources issues, including compensation, benefits, work life, and integrated total rewards to attract, motivate, and retain a talented workforce.

**Q. What have your job responsibilities entailed with Consumers Energy?**

A. In February 2002, I joined Consumers Energy as a Financial Reporting and Technical Accounting Analyst. My duties included accounting and reporting of equity-based compensation, technical accounting standard research, and preparation of quarterly and annual Securities and Exchange Commission ("SEC") filings. After eight years of progressing responsibilities in this role, I transferred to the position of Principal Human Resources Consultant. In 2013, I was promoted to the position of Director of Compensation. In this role I had the responsibility for administering Consumers Energy's compensation function and partnering with Labor Relations on union compensation

matters. This included developing compensation programs designed to attract and retain a qualified workforce for the Company. My duties included gathering of comparable wage and salary data in order to determine how Consumers Energy's pay level compares to the labor market and developing compensation programs that are competitive and deliver pay to employees that is fair and equitable and that motivates employees to perform at their full potential.

My responsibilities also consisted of assisting with preparation of materials for the Compensation Committees of the Consumers Energy and CMS Energy Boards of Directors, including the Compensation Discussion & Analysis section of the annual proxy statement for the named executive officers.

In May 2018, I took on the role of Director of Executive and Incentive Compensation. My responsibilities consisted of assisting with preparation of materials for the Compensation Committees of the Consumers Energy and CMS Energy Boards of Directors, including the Compensation Discussion & Analysis section of the annual proxy statement for the named executive officers. My responsibilities also included administering the incentive plans for CMS Energy, including Consumers Energy.

In August 2023, I took on the role of Manager of Compensation Operations. My Manager of Compensation Operations responsibilities consisted of the implementation of new and revised non-officer compensation programs, policies, and procedures for non-officers to align with the Company's goals and competitive practices. This position is also responsible for ensuring that compensation programs are consistently administered in compliance with internal policies and government regulations. The Manager of Compensation Operations role focuses primarily on the coordination and implementation

of the non-officer merit, incentive, stock administration, survey participation, and ensuring accuracy of data for non-officer programs.

In January 2024, I took on the role of Director of Compensation. My Director of Compensation responsibilities consist of the implementation of new and revised officer and non-officer compensation programs, policies, and procedures for officers and non-officers to align with the Company's goals and competitive practices. This position is also responsible for ensuring that compensation programs are consistently administered in compliance with internal policies and government regulations. The Director of Compensation Operations role focuses primarily on the coordination and implementation of the officer and non-officer merit, incentive, stock administration, survey participation, and ensuring accuracy of data for officer and non-officer programs. Lastly, the Director of Compensation consists of assisting with preparation of materials for the Compensation Committees of the Consumers Energy and CMS Energy Boards of Directors, including the Compensation Discussion & Analysis section of the annual proxy statement for the named executive officers.

**Q. Have you previously testified before the Michigan Public Service Commission ("MPSC" or the "Commission")?**

A. Yes, I have testified in Case Nos. U-17087, U-17197, U-17643, U-17735, U-17882, U-17990, U-18124, U-18322, U-18424, U-20134, U-20322, U-20650, U-20697, U-21148, U-21224, U-21308, U-21389, and U-21490.

**Q. What is the purpose of your direct testimony?**

A. The purpose of my direct testimony is to provide support for Consumers Energy's request for rate recovery for costs of its annual Employee Incentive Compensation Plan ("EICP")

at target levels. The EICP is a form of short-term incentive. Short-term incentive pay is designed to focus and reward performance over periods of approximately one year or less.

First, I will discuss Consumers Energy's overall compensation philosophy. In this section of my direct testimony, I will discuss the importance of paying employees a competitive level of compensation and the reasonableness of the overall compensation levels that the Company is requesting in this case. In addition, I will discuss (i) the fact that EICP compensation is part of an employee's overall market-based compensation and not in addition to it, and (ii) why Consumers Energy has included EICP at target levels as part of overall market-based compensation.

Second, I will discuss the EICP incentives and provide support for the Company's request for rate recovery in this case related to Consumers Energy's non-officer and officer operational goal portion of EICP. In my direct testimony, I will discuss the design of the EICP.

Third, I will discuss customer-related benefits that result from use of the incentive plans and how customers are best served when Consumers Energy can attract, retain, and motivate a talented workforce with compensation packages that are competitive and fair. Elimination of the EICP would result in Consumers Energy's employee compensation being below market and would hinder the Company's ability to attract and retain a qualified workforce that best serves customers.

**Q. Please summarize your conclusions.**

A. My conclusions include the following: (i) use of incentive compensation by utility companies is an accepted, common, and reasonable practice; (ii) Consumers Energy's decision to make a portion of compensation at-risk and subject to incentives is reasonable;

(iii) the amount of overall compensation included by Consumers Energy in this case is reasonable and is reasonably necessary to attracting and retaining a talented workforce; (iv) incentive compensation is part of the reasonable level of market-based compensation and not in addition to it; (v) recovering costs of Consumers Energy's EICP employee incentive plans will not result in excess rates; (vi) Consumers Energy's EICP performance goals and thresholds provide customer-related benefits; and (vii) the EICP goals provide customer-related benefits at no incremental cost to customers above those included in market-based compensation.

**Q. How is the remainder of your direct testimony organized?**

A. The remainder of my direct testimony is organized as follows:

**I. OVERVIEW**

**II. EMPLOYEE COMPENSATION PHILOSOPHY**

**III. INCENTIVE COMPENSATION PLANS**

**A. Description of Incentive Plans**

**B. Assessment of Customer Benefits of the Incentive Compensation Plans**

**IV. CONCLUSION**

**Q. Are you sponsoring any exhibits?**

A. Yes. I am sponsoring the following exhibits:

| | |
|---|---|
| Exhibit A-39 (AMC-1) | EICP Performance Measures; |
| Exhibit A-40 (AMC-2) | Target Pay Level Market Analysis; and |
| Exhibit A-41 (AMC-3) | Summary of Actual and Projected – Annual Incentive O&M Expenses. |

**Q. Were these exhibits prepared by you or under your supervision?**

A. Yes.

## I. OVERVIEW

**Q. What is the Company's compensation philosophy for non-officer employees?**

A. Consumers Energy's compensation philosophy for its non-officer, non-union employees is to provide market-based compensation tied to performance. A competitive compensation policy benefits customers by attracting and retaining employees with the necessary skills and experience to deliver world-class customer service and minimize the risks and costs of employee turnover. Incentive pay is a component of providing market-based compensation.

**Q. What is the Company's compensation philosophy for officer employees?**

A. Consumers Energy's compensation philosophy for its officers is centered around four principles:

1. Align with increasing shareholder and customer value;
2. Enable the Company to compete for and secure top executive talent;
3. Reward measurable results; and
4. Be fair and competitive.

Incentive pay is a reasonable component of delivering this philosophy.

**Q. How does Consumers Energy structure non-officer compensation for its salaried employees?**

A. Consumers Energy first determines what a competitive level of pay is for salaried non-officer employees. It does so by using various market surveys. The practice of using multiple surveys is common practice. It allows for a broader participant pool and confirmation that the survey data is representative of market competitive wages and trends. Consumers Energy then structures the compensation by allocating this market-based wage

between base salary and incentive compensation. The incentive compensation is part of the overall total market-based competitive level and it is not in addition to it.

**Q. How does Consumers Energy structure officer compensation?**

A. Officer compensation levels are determined by the Compensation Committees of the Boards of Directors of Consumers Energy and CMS Energy. The Company creates a compensation package for officers that delivers base salary, annual incentive compensation, and long-term incentive compensation targeted at the median or 50$^{th}$ percentile of the competitive market. In determining individual officer compensation levels, the Compensation Committees are advised by an independent third-party consultant and take into consideration market research, experience levels, and individual contributions.

**Q. In this proceeding, is the Company requesting rate recovery of all Operating and Maintenance ("O&M") gas expenses related to short-term incentive compensation plans?**

A. No. The Company utilizes both financial and non-financial (operational) goals in its short-term incentive compensation plan. While the Company believes that both financial and non-financial (operating) short-term incentive compensation expenses are reasonable, the Company in this case is excluding the costs of short-term incentive compensation linked to financial goals ($7.6 million). Included in that $7.6 million amount is the removal of the affordability (O&M savings) operational measure. The Company determined that the affordability measure, although included among the Company's operational goals for purposes of the EICP, is financial in nature; therefore, the Company removed the dollars

attributable to that measure from the rate request in this case along with the dollars attributable to the other financial measures.

**Q. Is Consumers Energy requesting recovery of all officer incentive pay linked to non-financial (operational) goals in this rate case proceeding?**

A. Yes. The Company in this case is seeking recovery for the incentive costs associated with the operational goals portion for all officers. This is a result of 30% of officer pay directly linked to operational measures. In prior cases, the Company excluded the top five officers, but sought recovery of all measures which were 100% financial with a modifier to the non-officer non-financial goals.

**Q. Is Consumers Energy requesting recovery of long-term incentive pay in this rate case proceeding?**

A. No. The Company is not seeking recovery for the costs of long-term incentive compensation (sometimes referred to as restricted stock plans) in its rate recovery request in this case.

**Q. Why is the Company requesting rate recovery of short-term incentive compensation operational goal expenses?**

A. Consumers Energy uses market data to determine an overall competitive level of compensation. Competitive compensation includes base salary and short-term incentive compensation for officers and non-officers. Consumers Energy's overall compensation levels are reasonable compared to the market. Compensation levels without these incentive payments would be below market competitive levels. Paying non-competitive levels of compensation would result in a less qualified workforce that would not best serve customers. A November 2021, Wall Street Journal entry stated:

> Many senior executives are struggling with an urgent talent crisis: The Great Resignation. The COVID-19 pandemic has induced waves of people to quit their jobs, seemingly in search of more meaning, more money, and more flexibility, among other wish-list items. The labor and skills shortage is now so severe that CEOs rank it as the No. 1 external issue they expect to influence or disrupt their business strategy within the next 12 months.

In order to hire and retain qualified personnel, it is necessary to either pay a competitive incentive or increase base salaries to make up for the missing incentive compensation component. Use of annual incentive mechanisms is a recognized management technique for companies, including utility companies. As I discuss later in my direct testimony, incentive pay is the number one compensation design element used to influence short- to mid-term performance results. Incentive mechanisms help communicate priorities, engage the employees in operating and financial success, reward valued skills and behaviors, and create business understanding for employees. Consumers Energy's incentive programs are structured in a way that is designed to help keep non-officers and officers focused on operational performance areas such as continuous improvement, safety, cost, reliability, and delivery. The incentive compensation program encourages employees to deliver outcomes which result in meeting customers' expectations. The EICP incentive compensation costs are reasonable costs of doing business and, therefore, should be recovered in rates.

**Q. Who is eligible for the EICP incentives?**

A. All non-union employees are eligible for EICP incentives, with the exception of employees who are rated as "under-contributing" or "needs improvement" on their annual performance appraisals. These under-performing employees are ineligible to receive an EICP incentive. Both non-officers and officers participate in an annual EICP incentive.

**Q. How are the EICP incentives structured?**

A. The EICP incentives are structured by non-officer and officer EICP. The 2023 non-officer EICP equally weights the operational measures with the financial measures:

- Half (50.0%) of employees' incentive will be based on the achievement of operational performance measures. (For 2023 and 2024, there are six operational measures.); and

- Half (50.0%) of employees' incentive will be based on the achievement of one financial measure, Earnings Per Share ("EPS"). Consumers Energy is a vital part of the Michigan economy, and it is important that the utility remains financially strong so that it can provide the utility service that customers expect and deserve; however, Consumers Energy is not seeking recovery of the financial portion of the EICP.

The goals are the same for the officer EICP, but the weightings are different. Officers are 30% based on the achievement of operational measures and 70% based on the achievement of financial measures.

## II. EMPLOYEE COMPENSATION PHILOSOPHY

**Q. What is Consumer Energy's philosophy about the overall level of compensation?**

A. The Company's management believes Consumers Energy should pay a fair and reasonable salary, comparable to the market that is equitable to employees, consistent with Company values and strategies, and that supports the highest level of customer service at a reasonable cost.

**Q. What are the components of Consumers Energy's compensation for non-officer employees?**

A. There are two parts of overall compensation for non-officer employees of Consumers Energy. The first part is base pay or salary. The second part for salaried employees is annual incentive compensation.

**Q. What are the components of Consumers Energy's compensation for officers?**

A. There are three parts of overall compensation for officers of Consumers Energy. The first two parts are cash compensation through base pay and annual incentive compensation. The third part is equity-based long-term incentive. As I mentioned earlier in my direct testimony, the Company is not seeking recovery for the costs of long-term incentive compensation in its rate recovery request in this case.

**Q. Why does the Company make a portion of compensation subject to incentives?**

A. A wide body of research supports the view that incentive pay (a variable pay component) works. One researcher states, "theory and research show that incentive pay can substantially increase individual and organizational performance and can represent a powerful tool for establishing a competitive advantage within an industry." (Dow Scott, *Incentive Pay: Creating a Competitive Advantage* – WorldatWork Press, 2007). There are many more cases of incentive plans as an effective motivational tool. Group incentive plans can contribute to organizational collaboration and achievement of company goals which lead to benefits for customers. A May 15, 2018, Forbes article entitled "The Key to an Effective Incentive Plan" (Bill Fotsch and John Case) continues to support this theory indicating:

> Incentive plans, by definition, are supposed to affect people's behavior on the job, day in and day out. They incent people to work harder and smarter, to go the extra mile, to collaborate with their coworkers, to come up with new ideas to improve some aspect of the business.

People don't work for money alone, but they do respond to incentives.

When properly selected and implemented, incentives motivate employees, focus employees on a company's goals, and increase both individual work performance and team

performance. When goals are challenging yet achievable, employees are motivated to increase productivity and performance to achieve the goal. In addition, incentives increase a company's ability to attract, hire, and retain qualified and motivated individuals. A study by the International Society of Performance Improvement showed that incentive pay programs increase performance by an average of 22.0%. (International Society of Performance Improvement, "Incentives Motivation and Workplace Performance Research and Best Practices," Spring 2002). As stated by the Society of Human Resource Management:

> Research has demonstrated that some human resource programs and initiatives produce a significant impact on performance in organizations (as measured by factors such as quality, productivity, speed, customer satisfaction and unwanted turnover). The two initiatives that consistently showed statistically significant positive results were linking pay to performance and using variable pay. Research has established the potential of variable pay to produce the desired business results. [Robert Greene, "Variable Pay: How to Manage it Effectively, Society of Human Resource Management," April 2003.]

Consumers Energy has adopted incentives that are designed to emphasize operational performance criteria in areas that are critical to the Company's utility business and customers. Focusing employees on these goals provides both qualitative and quantitative benefits for Consumers Energy's utility customers. High-level qualitative customer benefits are listed later in my testimony. Company witness Ashley E. Meschke's testimony illustrates the quantitative benefits to customers.

**Q. Are the overall compensation levels for employees subject to the non-officer EICP reasonable?**

A. Yes. Overall compensation levels for employees subject to the non-officer EICP and management's decision of how to allocate the overall compensation between base salary

and EICP are reasonable. As stated later in my testimony, it is common practice for companies to have a variable pay (i.e. EICP) component of total competitive compensation levels.

**Q. How does Consumers Energy determine what level of overall compensation for non-officers is reasonable?**

A. First, Consumers Energy's management targets compensation to the market median. Second, Consumers Energy's management actively reviews compensation levels so that employees are neither overpaid nor underpaid relative to the market. Third, the Company uses a rigorous survey process which uses valid and reliable data from multiple third-party sources to determine median levels of compensation. Forth, the Company reviews incentive compensation levels from third-party data sources to determine the target level of compensation. The fact that a portion of the compensation is in the form of an incentive payment does not mean that employees are paid in excess of market rates when they receive their incentive payment. To the contrary, removing the incentive from employees' compensation package or failing to meet incentive performance goals, would render their compensation below-market.

**Q. Would it be reasonable for Consumers Energy to pay employees below market level on an ongoing basis?**

A. No.

**Q. Why would it be unreasonable for Consumers Energy to pay below market level?**

A. Consumers Energy has a responsibility to customers to employ a competent workforce that is ready, willing, and best able to provide service for its customers. Paying competitive wages and salaries is necessary to fulfill that commitment. It would not be reasonable or

fair to the Company, its employees, or customers for the MPSC to set rates at a level that did not include reasonable levels of overall market-based compensation.

The level of service that customers deserve requires a qualified, experienced, and motivated workforce. The Company can attract, retain, and motivate talented employees when its overall compensation is competitive with market levels. A decision to compensate employees below market levels would detract from the Company's ability to assemble the committed and customer-focused workforce that customers deserve. Over time, this would be detrimental to customers, as well as being unreasonable to the Company's diligent, hardworking employees. Compensating employees below market levels will eventually result in their leaving for jobs that are paying at market levels. Over time, the workforce would tend to be less qualified, less experienced, less productive, and less capable of serving customers (as the most capable would, in general, tend to go to employers paying at competitive levels). This, in turn, could lead to less efficiency and could result in a need to hire more employees to produce the same service to customers, thus increasing costs to customers.

**Q. How does the Company determine the level of compensation for salaried non-officer employees?**

A. For salaried non-officer employees, the Company uses salary survey data from utility and energy companies. Using this survey data, a benchmarking analysis of base pay and incentive pay is made between the Company's jobs and comparable survey jobs. Benchmarking analysis is a comparison of jobs commonly found in the labor marketplace and/or a job that is highly relevant/populated within a company. This comparison indicates where the Company's pay stands relative to the market. The Company's goal is to target

base pay levels within plus or minus 5.0% of the market median for non-officers. While pay for individuals inevitably varies from the survey market levels due to differences in experience levels, education, job performance, longevity, position responsibilities, etc., the survey data indicate that the Company's overall non-officer compensation levels, assuming the EICP payment at the target level, are on average within target pay level of plus or minus 5.0% of market median. Exhibit A-40 (AMC-2) provides a summary of average exempt and non-exempt base pay for Company benchmark jobs compared to market using 2023 data for 2024 pay structure purposes.

Paying compensation that approximates the market median is particularly important given that Consumers Energy will continue to experience significant attrition (current employees eligible for retirement is 17% of the workforce) and have a need over the next few years to hire engineers, information technology, and other personnel to staff various projects and serve customers. Competitive pay is necessary to retain the talent needed to deliver on the Company's Integrated Resource Plan ("IRP"). In competing for engineers, as well as other personnel that are skilled, high-performing customer-focused candidates, it will be important to have a reputation for paying a competitive level of overall compensation. Excluding the incentive target amounts would result in the Company's pay levels being as much as or greater than 10.0% below market level.

**Q. How do you know the market data that the Company is using are appropriate and are not inflating salary levels?**

A. The Company uses several third-party survey sources to compare to the non-officer salaried workforce. The Company participates in and uses an industry survey performed by Willis Towers Watson, Aon, and Mercer LLC ("Mercer"), which are well-respected,

independent third-party compensation experts. These surveys are conducted by surveying companies which report data on an anonymous basis. When using the survey data, the Company looks at the base pay and incentive reported for highly populated jobs for which there is a comparable job match. In this way, the Company is matching the relevant market, not trying to lead the market, and thus not inflating its overall compensation above prevailing market levels. By using multiple independent survey sources, the Company can determine if any one source is varying significantly from another.

**Q. Can you give an example of the relationship between the Company's base pay levels and the market's pay levels?**

A. See Exhibit A-40 (AMC-2) for a summary of average exempt and non-exempt base pay for Company benchmark jobs.

**Q. Are incentive plans common in the utility industry?**

A. Yes, incentive plans are quite common. Annual incentive programs are a critical and highly integral part of competitive compensation packages for many organizations. Research from Willis Towers Watson's 2012 Survey Report indicates that approximately 80.0% of companies offer annual incentive (variable pay) programs. That number is slightly higher at 81.2% for those companies within the utility industry sector. The survey data supports the conclusions that including incentive pay as part of a competitive pay package is a standard industry practice and is required to attract and retain good employees.

Research from Mercer's 2014/2015 U.S. Compensation Planning Survey Report indicates that approximately 83.0% of companies offer annual incentive (variable pay) programs. For companies within the utility industry sector, the survey indicated that

98.0% of executives, 99.0% of management, 94.0% of non-sales professionals, and 86.0% of clerical and technicians were eligible for an annual incentive.

A 2012 Mercer study of more than 1,200 organizations reveals that actual company spending on variable pay for salaried exempt employees, as a percentage of pay, is 12.0% and salaried/hourly non-exempt employees, as a percentage of pay, is 6.0% to 7.0% for energy companies. A 2009 Hewitt Associates study of more than 1,100 organizations further reports that companies were budgeting variable pay for salaried exempt employees at 11.8%, and 5.5% to 6.1% for salaried/hourly non-exempt employees, for 2010. Ken Abosch, leader of Hewitt's North American Broad-Based Compensation Consulting business, added:

> Over the past decade, we've seen companies steadily shift from a fixed pay model to one that emphasizes true performance-based awards, and we expect this trend will continue.

Consumers Energy's practice of making a portion of overall employee compensation subject to incentives is consistent with best practices for compensation.

**Q. What has been the trend in variable or incentive pay?**

A. A 2016 study by Aon Hewitt indicated a 72% growth in variable pay spend over the past 20 years. Variable pay grew from 4.1% of base salaries in 1996 to 12.9% of base salaries in 2015. Business incentive plans are the most prevalent with 77% of companies using this type of variable pay award in 2015 up from 55% in 1996. Business incentive plans refer to plans that are based on Company financial and/or operational goals. According to a 2021 study published by WorldatWork and Compensation Advisory Partners, the vast majority of companies (99%) have short-term incentive programs ("Incentive Pay Practices: Publicly Traded Companies," July 2021, WorldatWork and Compensation

Advisory Partners). Moreover, a 2020 study by Willis Towers Watson on Salary Increases shows that 89% of Energy companies utilized short-term incentive (EICP) compensation programs.

**Q. Why is the use of incentive pay such a widespread practice?**

A. Incentive pay is the number one design used to influence short- to mid-term business or performance results. Coupled with clear strategy, solid leadership, and good, safe working conditions, variable pay incentive designs:

- Increase employees' understanding of what is important to the Company;
- Increase employees' identification with the Company's success and the factors by which it is measured;
- Reward valued skills and behaviors; and
- Enhance employee engagement by educating them on how and why their contributions will benefit them, the Company, and our customers.

Dividing overall compensation between base salary and incentive compensation is an approach that is common and effective in business today.

**Q. How many employees does the Company have that will be eligible for the non-officer EICP payout?**

A. Consumers Energy has approximately 4,500 employees (total utility) who are eligible to receive an incentive if, and when, the requirements for a payout are met. The risk of no payout is the same for all these eligible employees. Either every eligible employee receives a payout, or no one receives any incentive compensation.

**Q. How did the Company determine the level of compensation that would be provided as incentive compensation for these eligible employees?**

A. For the historical test year, the EICP target level for each pay grade was established by reviewing third-party market data on the mix of base salary and at-risk variable pay (EICP), historical rate case relief and amounts that will assist in motivating performance that will result in benefits to customers. The EICP compensation is part of the overall market-based competitive level of compensation, not in addition to it. Beginning in 2024, the EICP target levels are based on career stream and job level established by reviewing third-party market data on the mix of base salary and at-risk variable pay.

**Q. Explain if the Company reduced base pay when it started to pay incentive awards in order to obtain market-based pay based on the combination of the two components of pay.**

A. The Company has always had a broad-based incentive compensation plan in place for salary grades 19 and above (typically management level). In 2003, an EICP for employees in salary grades 18 and below (typically individual contributors in technical, professional, or support roles) was initiated. Base pay levels were not reduced for these employees at the time the plan was implemented. This was due to the fact that at the time the plan was implemented, total compensation, which is base salary and annual incentive, was slightly below the 50$^{th}$ percentile (median) point of survey results. The Company targets pay levels of plus or minus 5.0% of market median. The Company's pay level, including the additional incentive, continues to be within this range.

**Q. Is there an alternative to providing incentive pay for salaried employees?**

A. The alternative would be to increase the base compensation to a level that approximates the overall competitive market level of compensation. Absent the higher base pay, Consumers Energy's compensation offering would not be competitive with the labor market. For example, if the base target were $50,000 for a hypothetical job and market-based average pay was $50,000 plus a $2,000 incentive award, then the Company would need to offer $52,000 to match the market's current pay. So, the alternative to having an incentive component of overall compensation would be to raise base pay to the market's overall compensation. Eliminating incentive pay would result in the same compensation costs, but employees would lose focus on continuous improvement, safety, quality, cost, reliability, and delivery to the customer. Increasing base pay would also result in a higher level of fixed costs tied to base pay, such as certain pension and defined contribution benefit plans, life insurance, disability insurance, and other salary-based employee benefits.

The Company's overall compensation needs to be comparable to the market for salaried employees regardless of whether it is composed of only base pay or composed of base pay plus the target incentive award amount. The Company has maintained overall compensation at competitive levels through base pay plus the target incentive award amount.

**Q. Would elimination of incentive pay be in the best interests of customers?**

A. No. With incentive compensation, the employees and the Company must re-earn the at-risk compensation each year. If high levels of performance are not met each year, incentive pay can be reduced or eliminated. The elimination of variable "at risk" pay would create

a situation where all compensation is guaranteed and would remove an important incentive to improve service. This result would be counter to customer interests. The elimination of variable "at risk" pay would create a situation where compensation would be below market competitive levels. Competitive pay is needed to attract and retain the high-quality talent required to deliver exceptional service to customers. It would be difficult to achieve the Company's purpose of world-class performance delivering hometown service without the right talent. The knowledge, skills, and abilities of Consumers Energy's employees are key determinants in the quality and timeliness of service that customers receive. Our ability to deliver what customers expect such as reliable and safe energy delivery, on-time completion of service orders, and energy savings depends upon having the right talent in the right job at the right time. Having incentive compensation that is structured around goals that provide benefits to customers is in the best interest of the customer.

**Q. How does the Company determine the level of overall compensation for officers?**

A. A utility must maintain a competitive total compensation package to attract and retain executive talent. As discussed above, Consumers Energy creates a compensation package for officers that delivers base salary, annual incentives, and long-term incentives (excluded from the Company's request in this rate case) targeted at the 50$^{th}$ percentile of the market, as defined by a Compensation Peer Group approved by the Compensation Committees of the Boards of Directors. The Compensation Peer Group consists of energy companies comparable in business focus and size to CMS Energy with which the Company might compete for executive talent. The Compensation Peer Group currently includes 18 companies.

**Q. How do you know the market data that you are using for officer compensation are appropriate and are not inflating salary levels?**

A. Annually, the Compensation Committees engage an independent third-party consultant to provide advice and information regarding compensation practices of a Compensation Peer Group, which it develops based on criteria discussed below, as well as taking into account additional information from published surveys of compensation in the public utility sector and general industry. During the Compensation Committee's review of officers' compensation levels, consideration is given to the advice and information received from the independent compensation consultant; however, the Compensation Committee is ultimately responsible for determining the form and amount of the compensation programs.

Where available by position, Compensation Peer Group data serves as the primary reference point for pay comparisons of utility specific roles, and broader survey data and published proxy data are also provided by the compensation consultant as a point of reference for utility-specific roles and comparisons of general industry roles. Where available by position, the independent executive compensation consultant of the Compensation Committee, gathers compensation data from Willis Towers Watson's Energy Services Executive Database (over 50 investor-owned utilities) and Willis Towers Watson's General Industry Executive Database (approximately 500 participating companies), which it regresses based on CMS Energy's revenues to provide additional market context to the Compensation Peer Group. In selecting members of the Compensation Peer Group, financial and operational characteristics are considered. The criteria for selection of the Compensation Peer Group included comparable revenue, relevant utility industry group, similar business mix (revenue mix between regulated and

non-regulated operations), and availability of compensation and financial performance data.

The survey data indicate that the Company's overall officer compensation levels, assuming the EICP and restricted stock payment at the target market-based level, are reasonable.

In addition, annually, proxy-advisor service companies Glass Lewis & Co. and Institutional Shareholders Services assist institutional investors in their advisory vote on the reasonableness of compensation pay and practices of the proxy-named executive officers by providing a vote recommendation. The incentive pay practices for the proxy-named executive officers are the same as for the remaining officer group. In 2023, both proxy advisory service firms recommended a vote "for" the proxy-named executive officer compensation pay and practices. Also, shareholders voted 97% in favor to approve executive compensation as described in the 2023 Proxy Statement which is above the S&P 500 average of 89%.

**Q. Does the independent consultant provide other services for CMS Energy or Consumers Energy that could result in a conflict of interest?**

A. No. The independent consultant is required to obtain approval of the Compensation Committee of the Boards of Directors before undertaking any activity on behalf of the management of CMS Energy or Consumers Energy. During the time the consultant has been engaged as the compensation consultant for the Boards of Directors, it has not performed any services on behalf of the management of CMS Energy or Consumers Energy. The independent consultant is hired by and serves the Compensation Committee; it is not hired by or providing services to CMS Energy or Consumers Energy.

**Q. Are surveys the only determining measure used in setting officer compensation levels?**

A. No. Additionally, the Compensation Committee considers experience levels and individual contributions of the respective officers.

**Q. Are incentive plans for officers common in the utility industry or in other industries?**

A. Yes, incentive plans are prevalent. Research from Mercer, U.S. Compensation Planning 2014/2015 survey indicates that approximately 96.0% of companies, and 98.0% of energy companies, offer annual incentive (variable pay) programs for officers. The survey data support the conclusions that including incentive pay as part of a competitive pay package is a standard practice and is required to attract and retain qualified officers.

## III. INCENTIVE COMPENSATION PLANS

### A. Description of Incentive Plans

**Q. Please describe the EICP that is in place for 2023.**

A. The EICP for 2023 is based on achieving performance goals related to critical areas of the Company's operations. The goals focus on continuous improvement measures and maintaining financial health to deliver value benefits to customers (not seeking recovery of financial goals in this case). The Company's EICP goals seek to encourage employees to provide reliable energy, customer value, and responsive service to customers, and to do so safely. Each year, the Company establishes utility-specific performance criteria which focus on continuous improvement goals and breakthrough goals. For 2023, there were six specific operational performance measures and one measure related to being financially healthy. The EICP Operational Performance Measures are summarized on Exhibit A-39

(AMC-1). The 2023 officers and non-officer goals and weighting are shown on page 1 and operational goal targets on page 2.

**Q. Please describe Exhibit A-39 (AMC-1).**

A. Exhibit A-39 (AMC-1) identifies the operational performance areas that the EICP focuses on and identifies the specific measures that have been adopted for each of these areas. For the 2023 historical year, 50.0% of the non-officer incentive compensation and 30% of officer incentive compensation was based on operational performance. For purposes of this rate case, the Affordability (O&M savings from Waste Elimination) measure associated cost has been removed from the rate request as the Company has determined that it is financial in nature.

**Q. Is the structure of the EICP goals for 2024 similar to 2023?**

A. The specific performance measures and targets for 2024 are, as in prior years, a combination of measures related to operational performance and financial performance. As indicated above, the Company is not seeking recovery of the financial performance measures in the case. For non-officers, the operational performance and financial health goals will be weighted equally (50% operational and 50% financial). For officers, the operational performance and financial performance measures are weighted 30% operational and 70% financial. The officer operational goals are the same as the non-officer operational goals.

**Q. Is the eligibility for the EICP plan for 2024 and the projected test year similar to 2023?**

A. In third quarter 2023, Consumers Energy implemented an updated job architecture. Job architecture encompasses job levels, job titling, pay grades, career paths, spans of control,

the criteria for career movement, and equitable compensation programs based on job value. Job architecture serves as the foundation that will help the Company attract and retain the high-quality talent required to deliver service to customers. As a part of implementing the new job architecture, compensation programs such as the EICP were reviewed. This review resulted in the EICP target for non-officers to shift from one based on pay or salary grade to one based on career stream (management, professional, technical, or support) and level (i.e. entry, career, senior, supervisor, manager, director, etc.). With this change, the EICP continues to provide a link to the Company strategy and what is important to delivering safe and reliable energy to customers.

**Q. Will the non-officer performance measures continue to incorporate measures that provide benefits to Consumers Energy's customers?**

A. Yes. Performance measures will continue the focus on world class performance delivering hometown service and will continue to have as their foundation continuous improvement and breakthrough measures. While the number and precise phrasing of operational goals may vary from the historical test year, areas of focus will continue to include safety, reliability, cost, delivery, and customer care.

**Q. Will the officer performance measures continue to incorporate measures that provide benefits to Consumers Energy's customers?**

A. Yes. Operational and financial performance measures will continue the focus on world class performance delivering hometown service and will continue to have as their foundation continuous improvement and breakthrough measures. The operational measures will hold a weighting of 30%, meaning 30% of the officer incentive compensation is based on operational performance (same goals as non-officers) and the

remaining 70% is based on financial performance. As noted above, the Company is not seeking recovery of the financial performance measure in this case.

**Q. Please discuss the strategy and process for developing the EICP goals.**

A. Company witness Meschke provides a discussion of the strategy and process for developing the EICP goals.

**Q. Why has the Company's management chosen to design the EICP with broad goals and objectives on a Company-wide basis rather than individual goals and objectives for individual employees?**

A. It is necessary and appropriate for a large organization, such as Consumers Energy, to establish broad goals and objectives that are communicated to all employees as matters that are important to the success of the organization. Some employees will be in a better position to influence whether particular goals and objectives are met, but having every employee linked to a set of common customer-focused objectives is an effective method for emphasizing the importance of customer value and service. Having common goals and objectives (i) provides clear communication of Company goals, (ii) encourages employees to support each other and work together for common goals, and (iii) provides a scorecard with a focus on corporate-wide goals that benefit customers.

Consumers Energy incorporates individual goals through the annual performance feedback process, which includes the creation and review of individual goals and objectives for each salaried employee and the opportunity to recognize and reward individual performance. The existence of a common set of customer objectives enables supervisors and employees to establish individual goals and objectives which are supportive of, and in alignment with, the corporate goals reflected in the EICP.

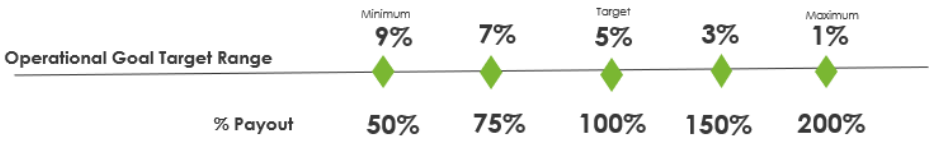
**Q. How are the payout levels that are shown on Exhibit A-39 (AMC-1) set?**

A. When setting payout levels, threshold is set at a level of achievement that can typically be reached 80% to 90% of the time in a 10-year period. Maximum payout is for exceptional performance (10% to 20% of the time in a 10-year period). These levels are to engage the employees in meeting the goals. Employees must re-earn the incentive at-risk portion of compensation each year. If the threshold to achieve a payout were set at a level viewed as not achievable, it would be difficult to maintain employee motivation and would result in fewer customer benefits. Overall compensation levels, including the EICP at target (100%) level that Consumers Energy seeks, are not excessive. It is reasonable for Consumers Energy to pay its employees competitive levels of compensation.

**Q. Are the payout levels that are shown on Exhibit A-39 (AMC-1) similar to 2023 and the projected test year?**

A. Yes, each operational measure will have its own threshold, target, and maximum for payout. This practice aligns better to market practice and with engaging and motivating performance. Gallup research supports substantial and well-established connections between employee engagement and the achievement of outcomes critical to the business and to customers. See illustration of banded goals below:

**Example (Illustration Only):**




This structure was in place for 2023 and planned to be in place for the projected test year.

**Q. Why are you including both gas and electric performance measures in this plan as this is a gas rate case?**

A. For purposes of efficiency and improved service, the Company has combined operations as one organization. For that reason, the plan contains both gas and electric measures.

**Q. How are the targets for the annual officer EICP incentives measures determined?**

A. As mentioned earlier, the goals are the same for the officer and non-officer EICPs, but the weightings are different.

**Q. Why is the weighting different for the officer plan?**

A. Officer annual incentive awards were based on the achievement of EPS and utility operational goals for the historical test year. As indicated above, the officer plan has a 30% weighting of the same operational goals as non-officers. This strengthens the linkage of officer and non-officer performance while aligning with typical indicators of officer strategy execution through financial goals (weighted at 70%) and corresponding higher weighting.

**Q. How are the target amounts for the annual officer incentives determined?**

A. The Compensation Committee determines the target amounts of the annual officer incentives. In determining the amount of target incentives, the Compensation Committee considers the following factors:

- The target incentive level and actual incentives paid in recent years;
- The relative importance, in any given year, of each performance goal established; and
- The advice of the Compensation Committee's compensation consultant as to compensation practices at other companies in the Compensation Peer Group and the utility industry.

**B. Assessment of Customer Benefits of the Incentive Compensation Plans**

**Q. What level of expenses for Consumers Energy's incentive plans has been included in the test year revenue requirement?**

A. The Company is requesting recovery of gas O&M expenses related to EICP incentive compensation plans at target (100.0%) levels. The following is a listing of the goals illustrated in Exhibit A-40 (AMC-2) for which the Company is requesting recovery:

- **Employee Safety** (OSHA Recordable)
  (Incidents, High Risk Injuries and Zero fatalities)
- **Culture Index**
  (Employee Empowerment, Employee Engagement and DEI)
- **Customer Experience** - Cxi
  (Survey measuring Customer Experience)
- **Electric Reliability** - SAIDI
  (System Average Interruption Duration Index)
- **Methane Emission Reduction**
  (Reduction of Methane Emissions through replacements of Mains and Services, etc.)

The level of expense is approximately $1.5 million as illustrated in Exhibit A-41 (AMC-3).

**Q. Please explain Exhibit A-41 (AMC-3), page 2.**

A. Exhibit A-41 (AMC-3), page 2, presents the amounts of the projected O&M expenses that were developed by applying either an inflation rate or a merit increase rate to historical O&M expense. Page 2, column (b), shows the historical O&M expense. Column (c) shows the historical amount that an inflation or labor rate was applied to. Columns (e) and (g) show the amounts to which an inflation rate or labor increase rate were applied for each bridge period, respectively. Columns (d), (f), and (h) show the labor and inflation increases for each respective period. Amounts that were projected using other methods are included in column (i). Column (j) is the projected test year O&M and is the sum of columns (b),

(d), (f), (h), and (i). For purposes of incentive expense, only labor increase is applicable. No inflation rate was applied.

**Q. How are the gas expenses of $1.5 million related to annual incentive compensation calculated?**

A. The $1.5 million for EICP incentive compensation is based on the following:

- For officers: The rate case expense amount is based on 2023 salaries multiplied by the approved target incentive percentage of salary from the 2023 Compensation & Human Resources Committee of the Board of Directors. Factors that impact the incentive expense year-over-year are retirements of officers and successors being at lower incentive amounts (decrease expense), forecasted salary increases (increase expense), and addition of new officers (increase expense) as indicated below.

- For non-officers: The rate case expense amount is based on an estimate of the number of employees in each career stream and job level multiplied by the plan prescribed incentive target amount. Progression to higher job levels as employees gain additional work experience will increase the amount of incentive expense year-over-year and headcount reductions will decrease the amount of incentive expense year-over-year.

**Q. How was the gas portion of the incentive compensation expense determined?**

A. The allocation percentages were supplied by the Accounting Department.

**Q. Is a portion of the gas incentive compensation expense allocated between O&M and capital?**

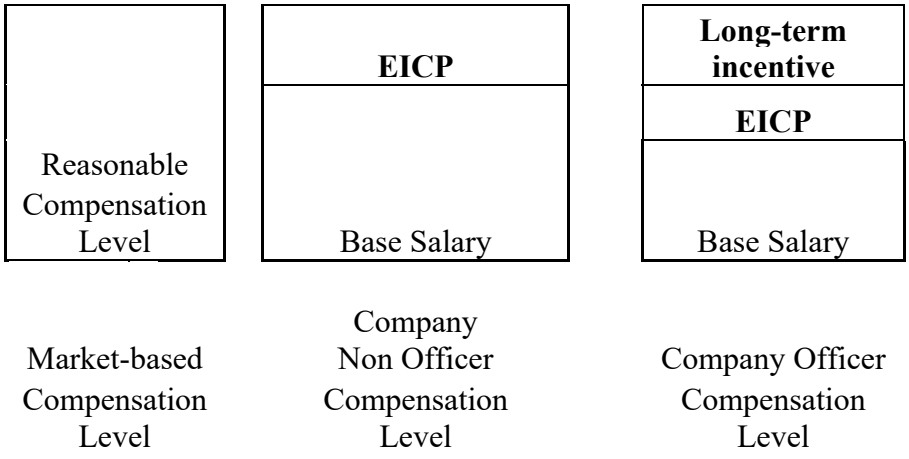
A. Yes. In the Company's 2014 Electric Rate Case, Case No. U-17735, the Commission issued an Order on November 19, 2015, approving the recovery of annual incentive (EICP) in rates for non-officers and non-proxy officers. As a result, in the first quarter of 2016, the Company began classifying annual incentive expense for the approved employee groups as a labor cost. The labor percentages charge between O&M and capital is based on labor studies performed by each business unit for the operational goals portion of the cost. Costs associated with financial performance measures are charged to O&M only.

**Q. Do Consumers Energy's gas customers benefit from making a portion of employee compensation subject to incentives?**

A. Yes. Paying a competitive level of compensation is an essential prerequisite to being able to attract, retain, and motivate qualified employees. Consumers Energy has determined a reasonable level of compensation and then made a portion of that compensation at risk. Structuring employee compensation so that it includes both base pay and incentive compensation provides motivation for an employee to strive for the total compensation for their position by contributing to the achievement of performance measures. Customers receive both qualitative and quantitative benefits at no additional cost above market-based compensation.

**Q. Why do you say there is no additional cost above market-based compensation?**

A. The officer and non-officer incentive plans are designed so that the total base salary plus incentive payments will be equivalent to the market-based compensation level. The EICP is part of the overall reasonable level of market-based compensation. It is not in addition to it. This is illustrated in the following diagram:



**Q. What is the appropriate standard from a business perspective in evaluating the reasonableness of the EICP costs?**

A. Making a portion of compensation subject to incentives is a recognized, well-established, common practice in the utility industry and is reasonable and appropriate. The appropriate standard from a business perspective in evaluating whether the level of compensation is reasonable is whether the *overall* level of compensation, including both base salary and incentive compensation, is reasonable. Using this standard would also be appropriate for ratemaking purposes. Looking at whether the overall level of compensation is reasonable will provide a better indication of whether the incentive plan results in excess rates than attempting to examine the cost allocable to the incentive compensation compared to benefits to customers. The overall level of compensation that Consumers Energy has included in its request in this case is reasonable.

**Q. Under the Company's proposal, do shareholders bear a portion of the EICP costs?**

A. Yes. The Company's incentive compensation proposal in this case does result in shareholders bearing a portion of incentive costs. The Company's proposal to include incentive compensation costs at target levels will result in the Company absorbing the incentive compensation costs in those years when the actual payouts are greater than target level and for the financial performance measures' cost. Thus, shareholders will absorb any resulting increase in costs arising from above-target performance and for financial measures. If actual payouts in future years are less than target levels due to under performance, then the Company's shareholders will absorb the consequence of underperformance results along with customers. The Company is allocating to

shareholders 100% of the costs of incentive compensation for above-target performance and financial measures.

**Q. Is the payment of incentive compensation reasonable given the economic conditions facing the Company's customers?**

A. Yes. The incentive compensation costs are reasonable costs of doing business. The market median of survey data reflects current economic conditions and current pay practices. The Company maintains an annual practice of surveying the external market. Any trends in compensation – increases/decreases – would be reflected in the market survey results. Paying a reasonable level of compensation is in the best interests of the Company's customers. Incentive compensation does not result in excessive compensation and is reasonably necessary to attract, retain, and motivate a talented workforce to serve customers. Further, gaps between the skills that employers require and those available in the labor market are growing. Paying a reasonable level of compensation which includes incentive compensation is necessary to attract, retain, and motivate a talented workforce. As of December 2023, the unemployment rate was 4.3% in Michigan and 3.7% nationally, according to the Bureau of Labor Statistics ("BLS"). In addition, BLS data show that there are more job openings in the United States than there are unemployed people. The war for talent is real, and the Company must offer a compelling value proposition to attract and retain the talent required to realize our Company purpose of world-class performance delivering hometown service.

**Q. Is the EICP a bonus or profit-sharing plan?**

A. No. The EICP is not a bonus or profit-sharing plan. A bonus is a discretionary payment given without predetermined goals or objectives and a profit-sharing plan entitles

employees to a share of the profits of the Company without pre-determined goals or objectives and is not part of total cash compensation market levels. Consumers Energy offers incentive compensation, which is based on predetermined goals and objectives and award levels. Incentive compensation is part of an employee's overall compensation and not in addition to it, like a bonus or profit-sharing plan. The fact that a portion of compensation is in the form of an incentive payment does not mean that employees are paid in excess of market rates when they receive their incentive payment. Employee compensation is a reasonable cost of doing business. If overall compensation levels are reasonable, then those costs should be recoverable through utility rates.

**Q. What are some of the ways the EICP incentives benefit customers?**

A. Customers derive benefits by having a portion of compensation shifted to the EICP Program since the goals of the program are in the interests of customers. Customer benefits are achieved without any additional cost to customers since this program has been structured as a "carve out" of the employee's base salary. If the EICP costs had not been allocated to incentive compensation, those costs would need to be recovered as base compensation for Consumers Energy to have a reasonable competitive level of compensation.

Also, customers are best served when Consumers Energy can attract, retain, and motivate talented salaried employees and executives with compensation packages that are competitive and fair. Performance-based incentives (like Consumers Energy's) permit the Company to provide an incentive to accomplish specific annual goals that represent performance priorities for Consumers Energy and its customers. With variable pay, the employee and the Company must re-earn the incentive award every year. If performance

goals are not achieved, cash compensation is reduced or eliminated. Variable pay creates a performance culture rather than an entitlement culture.

In addition, an incentive program structured to focus employee attention on operational performance results in both qualitative and quantitative customer benefits. Among other things, customers benefit from increased cyber security, reliability, and on-time delivery and the focus on employee and public safety that helps reduce potential increased costs.

A quantitative analysis of the benefits received by the customer as a result of the EICP is discussed by Company witness Meschke in her direct testimony in this case.

**Q. Has Consumers Energy assessed whether benefits to customers of this program equal or exceed costs?**

A. Yes. The performance measures provide appreciable benefits to customers. The costs of the EICP are projected at approximately $1.5 million for the test year. The quantifiable gas benefits illustrated in Company witness Meschke's direct testimony are $3.6 million, which shows that the benefits to customers of the Company's EICP Program outweigh the costs of the program. Since this amount is part of the overall level of reasonable compensation, rather than being in addition to it, all benefits to customers are achieved at zero additional cost to customers. Achievement of the Company's EICP goals and objectives result in pay that is competitive with the labor market, not above the market. The EICP costs are not in addition to the reasonable level of compensation, they are part of the reasonable level of market-based compensation. If these amounts are not paid, then overall compensation would be at a level which is below the market level. There is no valid basis to eliminate incentive costs from the cost of service recovered in rates because

they are a part of an incentive plan rather than including these costs as part of base pay. As stated before, overall levels of compensation are at levels that are not excessive. Rate recovery of 100.0% should be allowed.

## IV. CONCLUSION

**Q. Is the Company's overall compensation program, including the customer-focused incentive, reasonable?**

A. Yes. The approach used by the Company is a reasonable approach, is consistent with industry standards, and represents well-established best practices for creating customer focus through compensation design, and it does so without any additional customer cost above the market. The overall compensation levels are reasonable relative to the market, are determined in a reasonable manner, and are a reasonable cost of doing business. Compensation is structured in a manner that rewards improved operational and financial performance that benefits customers. The incentive compensation costs should, therefore, be included in the cost of service recovered from customers. These are legitimate and reasonable costs of doing business. Rates established in this rate case should include approximately $1.5 million for incentive compensation expense.

**Q. Please summarize reasons why full recovery of incentive compensation costs should be allowed in this case.**

A. Reasons that full recovery of operational goal incentive compensation costs should be allowed include the following:

- Employee compensation is a reasonable cost of doing business, has been set at a reasonable level, and has been determined using a reasonable methodology;
- The amount of compensation that is subject to incentive measurements is part of the market-based compensation level, not in addition to it;

- The incentive compensation plan does not result in excessive pay levels beyond what is reasonably necessary to attract a talented workforce to best serve the customer;

- Making a portion of compensation subject to incentives is a recognized, well-established, and common industry practice and is neither irrational nor unreasonable;

- The decision of Consumers Energy to allocate a portion of overall compensation that would otherwise have been in base pay so that it is subject to incentives does not provide a valid basis to disallow these expenses;

- The plan incorporates operational as well as financial performance goals;

- Quantitative and qualitative customer benefits of having a portion of compensation subject to incentives occur at no additional cost above market-based compensation to customers given the compensation structure adopted;

- Investors, including shareholders, bear the expense of incentive compensation in excess of the target levels and for incentive compensation provided to proxy officers; and

- The focus should be on whether the overall level of compensation is reasonable, not on the precise structure of the compensation program.

It is reasonable for Consumers Energy to pay its employees competitive levels of compensation. Paying employees at competitive market levels is reasonable and prudent. Those incentive pay costs are reasonable costs of doing business and are recoverable from customers.

**Q. Does this conclude your direct testimony?**

A. Yes.

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

| | | |
|---|---|---|
| In the matter of the application of<br>**CONSUMERS ENERGY COMPANY**<br>for authority to increase its rates for the<br>distribution of natural gas and for other relief. | )<br>)<br>)<br>)<br>) | Case No. U-21806 |

**REBUTTAL TESTIMONY**

**OF**

**AMY M. CONRAD**

**ON BEHALF OF**

**CONSUMERS ENERGY COMPANY**

May 2025

**Q. Please state your name and business address.**

A. My name is Amy M. Conrad, and my business address is One Energy Plaza, Jackson, Michigan 49201.

**Q. Are you the same Amy M. Conrad who previously submitted testimony in this case?**

A. Yes.

**Q. What is the purpose of your rebuttal testimony?**

A. The purpose of my testimony is to rebut the direct testimony and exhibits presented by witnesses for the Attorney General and the Michigan Public Service Commission ("MPSC" or the "Commission") Staff ("Staff") regarding Consumers Energy Company's ("Consumers Energy" or the "Company") incentive compensation plan and the recommendations to exclude incentive compensation costs from the revenue requirement in this case. For the reasons discussed in my direct testimony and in this rebuttal testimony, the Commission should find that the incentive compensation costs linked to operational measures that Consumers Energy is seeking to recover in this case are a reasonable cost of doing business and should be included in rates. Consumers Energy has acted reasonably in paying its employees at market levels. It would be unreasonable not to allow the Company to have that reasonable and appropriate business expense recovered in rates.

**Q. How is your rebuttal testimony organized?**

A. In Section I of my rebuttal testimony, I address the direct testimony and exhibits presented by Attorney General witness Sebastian Coppola. In Section II, I address the direct testimony and exhibits presented by Staff witness Theresa McMillan-Sepkoski.

**Q. Are you sponsoring any exhibits with your rebuttal testimony?**

A. Yes. I'm sponsoring Exhibit A-132 (AMC-4), which shows the data that was attached to audit response U21806-SA-CE-028, but which was excluded from Staff witness McMillan-Sepkoski's Exhibit S-8.2 reproducing that response.

**Q. Were these exhibits prepared by you or under your supervision?**

A. Yes.

## I. REBUTTAL TO ATTORNEY GENERAL WITNESS COPPOLA

**Q. At page 187, lines 12 through 13, of his direct testimony, Mr. Coppola states: "Generally, the Company's short-term incentive plans are too heavily weighted toward financial measures that mostly benefit shareholders and not customers." Do you agree?**

A. No, the Company is not requesting recovery of any Employee Incentive Compensation Plan ("EICP") dollars in this case related to the financial metrics**.** The Company in this case is seeking recovery only for the incentive costs at target level associated with the operational goals portion of the short-term incentive (EICP) for both non-officers and all officers. Consumers Energy has adopted incentives that are designed to emphasize operational performance criteria in areas that are critical to the Company's utility business and customers. Focusing employees on these goals provides both qualitative and quantitative benefits for Consumers Energy's utility customers.

**Q. At page 188, lines 10 through 13, Mr. Coppola states: "Even mediocre performance will be rewarded if only a single metric is achieved. This is a very generous incentive plan that is not directly connected with achieving superior customer benefits before making threshold incentive payouts." Do you agree?**

A. No. Employees, as a whole, must re-earn the incentive/at-risk portion of compensation each year. Moving to a banded goals payouts for each operational measure sets minimum (thresholds), targets, and maximum payout. The Company is only seeking recovery of target level payout. It is common market practice to use individual goals that set minimums (thresholds), targets, and maximum goals (banded goals) with payout percentages based on level of achievement. Structuring the payout to consider performance of each goal individually also ensures that employees have an independent motivation to achieve each goal regardless of whether another goal may be off target to meet payout levels during the year. This removes any potential mis-incentive to "give up" on one goal just because another may have become unlikely to be achieved. Each goal has the ability to earn an EICP payout on its own achievement, so every goal remains important and employee motivation to attain each goal individually remains high.

Rewarding employees for the level of achievement aligns pay for performance. Employees know what the minimum level of achievement is to receive a payout and have visibility to what above-target rewards they can receive for over achievement. This structure motivates employees to attain the target or goal but still allows for recognition for some below-target performance and additional reward for above-target performance.

If the threshold to achieve a payout was set at a level viewed as unachievable, it would be difficult to maintain employee motivation and would result in less customer

benefits. Overall compensation levels including the EICP are established at a target (100%) level that is not excessive. The incentive compensation portion of the Company's total compensation ensures that employees are provided a reasonable incentive to achieve exceptional performance levels. The Company's proposal to include incentive compensation costs at target levels will result in the Company absorbing the incentive compensation costs in those years when the actual payouts are greater than target level. Thus, shareholders will absorb any resulting increase in costs arising from above-target performance.

**Q. At page 188, lines 13 through 14, of his direct testimony, Mr. Coppola states: "[T]he fact that the performance measures use CMS Energy financial information and comingle electric and gas business measures is a concern." Do you agree?**

A. No. The incentive structure incorporates continuous improvement, safety, quality, cost, delivery, morale, and financial performance measures. Performance in these areas is critical for the Company's success in its electric public utility business. For purposes of efficiency and improved service, the Company has combined operations as one organization. For that reason, the plan contains both gas and electric measures. The related incentive expense is then allocated between electric and gas businesses based on multiple factors determined by the Accounting Department based on the type of activities the departments or business units perform. These factors include but are not limited to: (i) percentage of time; (ii) property, plant, and investments; (iii) operating revenue; (iv) headcount; and (v) labor. Only the gas portion of the EICP expense is being requested in this case. The Company has used this same approach for many rate cases with Commission approval of the recovery of the costs associated with the operational goals.

**Q. At page 188, of his direct testimony, Mr. Coppola states: "the Company has stated that it continues to pay salary increases each year of approximately 3.5%." Do you agree?**

A. No. For rate making purpose, the Company follows the direction of the Commission's Order in Case No. U-20963 and uses the same inflation factor to adjust both labor and non-labor expenses for determining projected labor costs. Consumers Energy's compensation is designed to be competitive with what is seen in the labor market including rewarding and motivating talent rather than trying to keep up with inflation.

**Q. At pages 186 through 187 of his direct testimony, Mr. Coppola discusses various reasons that he disagrees with the Company's request to recover incentive compensation costs in rates. Do the concerns and issues he has identified in his direct testimony provide a valid basis to not allow any recovery of incentive compensation costs in rates?**

A. No. I disagree with his analysis and his conclusions. Mr. Coppola's conclusion that Consumers Energy's incentive compensation plans do not benefit customers is not correct. A wide body of research supports the view that, when properly selected and implemented, as has been done with the Consumers Energy plans, incentives motivate employees, focus employees on a company's goals, and increase both individual work performance and team performance. The overall compensation levels are reasonable. The incentive compensation is part of the overall reasonable compensation level, not an addition to it.

**Q. At pages 186 through 187 of his direct testimony, Mr. Coppola states that "the average achievement rate for the past five years was 66%". Do you agree?**

A. No. I disagree with his analysis and his conclusions. The EICP operational payouts averaged 105% as shown in the table below:

| Performance Year | Operational Goal Payout % |
|---|---|
| 2020 | 125% |
| 2021 | 75% |
| 2022 | 109% |
| 2023 | 94% |
| 2024 | 124% |
| 5 Year Average | 105% |

The Company is requesting recovery of target level payout for operational measures only. When setting payout levels, threshold is set at a level of achievement that can typically be reached 80% to 90% of the time in a 10-year period. Maximum payout is for exceptional performance (10% to 20% of the time in a ten-year period). These levels are to engage the employees in meeting the goals. Employees must re-earn the incentive at-risk portion of compensation each year. If the threshold to achieve a payout were set at a level viewed as not achievable, it would be difficult to maintain employee motivation and would result in fewer customer benefits. When goals are challenging yet achievable, employees are motivated to increase productivity and performance to achieve the goal.

## II. REBUTTAL TO STAFF WITNESS MCMILLAN-SEPKOSKI

**Q. What is the pay process for officer incentive targets?**

A. As stated on page 21 of my direct testimony, Consumers Energy creates a compensation package for officers that delivers base salary, annual incentives, and long-term incentives (excluded from the Company's request in this rate case) targeted at the 50$^{th}$ percentile of the market, as defined by a Compensation Peer Group approved by the Compensation

Committees of the Board of Directors. Annually, the Compensation Committees engage an independent third-party consultant to provide advice and information regarding compensation practices of a Compensation Peer Group.

**Q. Is survey data information for the third-party consultant proprietary information?**

A. Yes. Consumers Energy's Compensation Committees engage an independent third-party consultant to provide information regarding officer compensation practices of the Compensation Peer Group as well as additional information from Willis Towers Watson published surveys of compensation in the public utility sector and general industry.

The Willis Towers Watson survey sources used by Pay Governance are produced solely for use by database participants and are maintained by Willis Towers Watson in connection with the participant's own internal human resources management department. The surveys are the confidential and proprietary work product of Willis Towers Watson, which owns all related intellectual property rights. Pay Governance has written consent from both Willis Towers Watson and CMS Energy to use the surveys on CMS Energy's behalf. Pay Governance is prohibited from using or reproducing the database and survey reports prepared by Willis Towers Watson.

**Q. Is the proprietary nature of officer compensation the reason the Company did not provide Staff with the compensation level of the top five officers compared to market median referenced in Staff Exhibit S-8.2?**

A. Yes. As illustrated in the Company's response shown in Staff Exhibit S-8.2, the market median information requested is confidential, proprietary, and commercially sensitive data belonging to third parties. Consumers Energy is contractually prohibited from sharing this information.

Although the Company is prohibited from sharing the market data used in setting compensation for its top five officers, the Company recognizes that it could be helpful for Staff to have access to some market data to evaluate the reasonableness of the compensation included in rates for the Company's top five officers. Therefore, the Company compiled and provided non-confidential market data using the following compensation elements from the Compensation Peer Group's publicly filed proxy statements: salary, stock awards, and non-equity incentive.

Because this market data uses only publicly available non-proprietary information, it does not perfectly represent the information that the Company used to benchmark and assist the Compensation Committee to determine compensation for Consumers Energy's top five officers. But, that does not support the conclusion that it is inadequate to support the level of compensation for the Company's top give officers. First, the proprietary benchmarking information alone does not mechanically decide how compensation will be set. When making pay adjustments, the Compensation Committee considers the CEO's recommendations, along with proprietary Compensation Peer Group data, internal equity, tenure, and other proprietary market data from surveys provided by the independent compensation consultant. Actual compensation decisions are based on the following as described on page 21 through page 24 in my testimony. Second, the data provided in Exhibit A-132 (AMC-4) is sufficiently consistent with the proprietary data that it does allow Staff to see a valid comparison of the compensation of the highest paid through the 2nd, 3rd, 4th and 5th highest paid named officers compared to the Company's compensation peer group. As Staff indicated, it was able to review the proprietary Pay Governance report under the following conditions set forth by the proprietary owners, Pay Governance:

> That it will review these materials in the presence of an appropriate representative of CMS and shall keep these extracts strictly confidential and shall not copy or distribute these extracts to any other party, shall use them solely for the purpose of this inquiry and shall exempt Pay Governance from public disclosure under any other inquiry or applicable freedom of information or open records acts.

As the owner of the reports, these were the conditions Pay Governance required. These were not limitations imposed by Consumers Energy. The report that Staff viewed contained the same data shared with the Compensation Committee of the Board for their decision making on officer compensation. In other words, Staff saw the exact data used in making the compensation decision for the top five officers.

**Q. At page 8 of her direct testimony, Ms. McMillan-Sepkoski states that, "There was no financial presentation of the compensation data that Staff needed to examine to make a valid comparison?" Do you agree?**

A. No. The presentation contained individual charts for all the officers that report to the Chief Executive Officer with the officer names redacted. These charts contain the percentages of base salary, total cash compensation and total direct compensation compared to market. The market data position titles were also contained on the charts. These charts allowed for a visual comparison of the position relative to the market of the top officers. There was also a summary table that illustrated the three market data references (Peer, Investor-Owned Utility, and General Industry) with "x" marking the position compared to the market each officer fell into (i.e. Below 15% of the market range, within +/- 15% of market, or Above 15% of the market range) for all officer positions. The information that Staff claims was missing was there.

**Q. Do you agree with Staff's recommendation to exclude the top five officer operational goal annual incentive expense?**

A. No. As stated above, having the officers hold specific operational measures provides a stronger linkage to Company operational incentive priorities that support customer benefits. This is a result of the addition of 30% of officer pay directly linked to operational measures. Starting in 2022, the officer operational goal modifier was removed, and the operating cash flow measure was replaced with the same operational measures as non-officers with a weighting of 30%.

In previous cases, the Company regarded the work performed by the top five officers as focused broadly across the entire CMS Energy enterprise; however, in light of the move to a 30% weighting on Consumers Energy-specific operational measures for EICP, we now have a measurable component of their compensation linked directly to work on behalf of the utility and to operational outcomes that benefit customers. Under the Company's current proposal in this case, shareholders continue to bear 100% of the cost of incentive compensation for financial measures and above-target operational measure performance.

**Q. Does this conclude your rebuttal testimony?**

A. Yes.

MR. RUSZKIEWICZ: Company's next witness is Matthew J. Foster. Based on the stipulation of the parties, the Company moves to bind in the testimony of Matthew J. Foster, which direct testimony consists of a cover page, plus 28 pages of prefiled testimony, and also rebuttal testimony that consists of a cover page and 3 pages of prefiled testimony.

Mr. Foster also had exhibits, and the Company moves to admit the exhibits in. Exhibits are A-43 through A-53, A-12 Schedule B-5.4, and Exhibit 1 -- A-134. Excuse me.

JUDGE VARCHETTI: All right. Are there any objections to the admission of Mr. Foster's direct and rebuttal testimony or any of the associated exhibits?

Hearing none, then, the direct and rebuttal testimony of Mr. Foster and the associated exhibits are admitted.

MR. RUSZKIEWICZ: Thank you, Your Honor.

(Direct and Rebuttal Testimony bound in)

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

| | | |
|---|---|---|
| In the matter of the application of **CONSUMERS ENERGY COMPANY** for authority to increase its rates for the distribution of natural gas and for other relief. | ) ) ) ) ) | Case No. U-21806 |

**DIRECT TESTIMONY**

**OF**

**MATTHEW J. FOSTER**

**ON BEHALF OF**

**CONSUMERS ENERGY COMPANY**

December 2024

**Q. Please state your name and business address.**

A. My name is Matthew J. Foster, and my business address is One Energy Plaza, Jackson, Michigan 49201.

**Q. By whom are you employed and in what capacity?**

A. I am a Principal Rate Analyst for Consumers Energy Company ("Consumers Energy" or the "Company").

**Q. Please state your educational background.**

A. I graduated from Michigan State University with a Bachelor of Business Administration with a major in finance.

**Q. What are your responsibilities in your current position?**

A. In my role as a Principal Rate Analyst, I am responsible for the development of Capital and Operations & Maintenance ("O&M") plan targets that align with rate case results.

**Q. Please describe your prior work experience.**

A. I have held my current position since April 2018. Prior to this role, I held various accounting analyst roles within the finance organization, including in the General Accounting and Property Accounting Departments. In these roles, I have been responsible for property records, depreciation analysis, financial results, accounting entry, analysis, and reporting, including Federal Energy Regulatory Commission ("FERC") and Michigan Public Service Commission ("MPSC" or the "Commission") report filings.

**Q. Have you previously testified before the Commission?**

A. Yes. I testified in Case Nos. U-21224, U-21308, U-21389, U-21490, and U-21585 which include the Company's most recent natural gas and electric general rate cases.

**Q. What is the purpose of your direct testimony in this proceeding?**

A. My direct testimony is in five parts. In Part 1, I am presenting testimony supporting the test year O&M expense for Corporate Services, uncollectible expense, injuries and damages, and Manufactured Gas Plant ("MGP") direct project management costs. In Part 2, I address the test year capital expenditure for Corporate Services. In Part 3, I address technology projects that support the Corporate Services functions. In Part 4, I am presenting testimony requesting approval for the use of regulatory assets or regulatory liabilities, as needed, by the Defined Benefit ("DB") Pension/Other Post-Employment Benefits ("OPEB") Volatility Mechanism. In Part 5, I am presenting testimony demonstrating Consumers Energy's compliance with the guidelines for intercompany transactions between affiliates as ordered by the Commission.

**Q. Are you sponsoring any exhibits in this proceeding?**

A. Yes. I am sponsoring the following exhibits:

| | |
|---|---|
| Exhibit A-43 (MJF-1) | Summary of Projected Gas & Common O&M Expense for the Years 2023, 2024, 2025; and the 12 Months Ending October 31, 2026; |
| Exhibit A-44 (MJF-2) | Gas Projected Corporate Services O&M Expense for the Years 2023, 2024, 2025; and the 12 Months Ending October 31, 2026; |
| Exhibit A-45 (MJF-3) | Gas Uncollectible Accounts Expense for the Years 2023, 2024, 2025; and the 12 Months Ending October 31, 2026; |
| Exhibit A-46 (MJF-4) | Gas Injuries and Damages Expense for the Years 2019 through the 12 Months Ending October 31, 2026; |
| Exhibit A-47 (MJF-5) | Manufactured Gas Plant Amortization Schedule and Direct |

| | | | |
|---|---|---|---|
| | | | Project Management Costs 2005 through the 12 Months Ending October 31, 2026; |
| | Exhibit A-48 (MJF-6) | | Organization Chart, Affiliate Group of Companies Doing Business with Consumers Energy Company – 2023; and Purpose of Business, Affiliate Group of Companies Doing Business with Consumers Energy Company – 2023; |
| | Exhibit A-49 (MJF-7) | | Summary of Costs Billed to Affiliated Companies for the Year Ended December 31, 2023; and Summary of Payments Made to Affiliated Companies for the Year Ended December 31, 2023; |
| | Exhibit A-50 (MJF-8) | | Impact on Gas Operations for Costs Billed to Affiliated Companies for the Year Ended December 31, 2023; |
| | Exhibit A-51 (MJF-9) | | Impact on Gas Operations for Payments Made to Affiliated Companies for the Year Ended December 31, 2023; |
| | Exhibit A-52 (MJF-10) | | Affiliated Companies – Rate of Return on Common Equity for the Year Ended December 31, 2023; |
| | Exhibit A-53 (MJF-11) | | 2023 Gas Utilities Ranked by A&G per Customer (less Pension and Benefits); and |
| | Exhibit A-12 (MJF-12) | Schedule B-5.4 | Gas Projected Corporate Services Capital Expense for the Years 2023, 2024, 2025; and the 12 Months Ending October 31, 2026. |

**Q. Were these exhibits prepared by you or under your direction and supervision?**

A. Yes, they were.

**PART 1 – GAS CORPORATE O&M EXPENSE**

**Q. Please describe Exhibit A-43 (MJF-1).**

A. Exhibit A-43 (MJF-1) summarizes the Company's total 2023 through the 12 months ending October 31, 2026 gas O&M expense for Corporate Services, uncollectible expense, injuries and damages, and MGP direct project management costs. Column (a) of this exhibit provides the O&M expense category, column (b) provides the source references, column (c) provides the 2023 actual O&M, column (d) provides the 2024 O&M projection, column (e) provides the 2025 O&M projection, and column (f) provides the projected test year 12 months ending October 31, 2026 O&M expense. These expense categories are discussed in detail below.

**Corporate Services O&M Expense**

**Q. What areas are included within the Corporate Services O&M expense category, as shown in Exhibit A-43 (MJF-1), line 1?**

A. Corporate Services includes those areas common to the administrative functions of a regulated corporation. These include Sustainability and External Affairs; Legal, Ethics, Regulatory and Risk Management; People and Culture ("P&C"), Learning and Development; Finance and Shared Services; General Activities; and administration and other costs.

**Q. Please provide a brief overview of the various areas within the Corporate Services area.**

A. The areas within Corporate Services include:

- Sustainability & External Affairs – This area acts as a conduit between the Company and its employees, customers, and external stakeholders. The group manages storm communications, promotes safety messaging, advances clean energy programs for the benefit of customers via public media relations and

inquiries, advertising, corporate news releases, social media management, and trade association dues and memberships. This area also manages regulatory commission expenses, foundation operations, and community programs. It is responsible for employee diversity and inclusion and strategic talent sourcing;

- Legal, Ethics, Regulatory, and Risk Management – This area includes the Legal Organization, the Corporate Compliance Department, the Corporate Secretary Department, the Securities Law Group, Corporate Information Governance, Risk Management, and it is responsible for determination and management of regulatory filings, and management of the interface between the Company and regulatory staffs. The Corporate Compliance Department is responsible for maintaining a healthy ethical culture, including training on the Company's Code of Conduct and Guide to Ethical Business Behavior, misconduct investigations, and oversight for 40 regulatory compliance areas. The Corporate Secretary Department is responsible for sound corporate governance, including board meetings, shareholder meetings, minutes, shareholder services, and Board of Directors costs. The Securities Law Group is responsible for ensuring full and fair disclosure to investors through compliance with public-company regulatory and legal requirements. Corporate Information Governance is responsible for creating and sustaining a company culture where all employees treat information as an asset, including adherence to the information governance principles: accountability, transparency, integrity, protection, compliance, availability, retention, and disposition. The Risk Management area provides services for corporate insurance programs, surety bonds, and review of commodity and credit risks associated with natural gas, electric fuel, and power purchases. Gas and electric insurance programs include the premiums for property and casualty insurance paid to cover the business including property damage, director and officer's liability insurance, public liability insurance, workers' compensation insurance, fiduciary liability insurance, and fidelity insurance. The Legal Organization is responsible for legal matters involving litigation, credit and collections, environmental, contracts, and other transactions, real property, labor and benefits, business development, and regulatory matters at the state and federal levels;

- P&C and Learning and Development – This area is responsible for creating and executing on the employee experience for all co-workers at Consumers Energy. An engaging employee experience is critical for hiring and retaining the necessary talent to benefit customers and the State of Michigan. The employee experience is comprised of all interactions and services that employees experience during their time with the Company, including recruiting, hiring, training and development, succession planning, compensation, payroll, performance management, workforce relations, employee engagement, and benefits administration. Also included is compliance assurance, which addresses legal and regulatory requirements such as Equal Employment Opportunity, Americans with Disabilities Act, and Family and Medical Leave Act;

- Finance and Shared Services – This area provides the preparation of utility strategic plans, budgets, forecasts, and specialized financial studies. This area also includes the preparation and control of accounting records, including financial statements and reports, and the administration of accounting systems. These systems include budgeting and management reporting, general ledger, accounts payable, fixed assets, and financial and regulatory reporting. The internal audit functions (appraisal of business unit effectiveness of financial controls) and the internal control functions are conducted in this area. The corporate tax function includes all aspects of compliance with federal, state, and local income, sales and use, property, franchise, and excise taxes, book accounting for taxes, tax planning of transactions, tax research, the analysis of tax legislation and regulations, the management and negotiation of tax audits, and tax litigation. Treasury includes all aspects of Company financing and cash management, negotiation of Company credit facilities, treasury operations including initiating cash wire transfer transactions, processing checks for deposit, maintenance of all bank account related activities, borrowing, and investing. In addition, investor relations, rating agency, and investor support are included in the Finance and Shared Services area. Shared Services includes fleet and facilities asset management, corporate safety, and supply chain;

- General Activities – These costs are an aggregation of expenses and credits that are not attributable to any one department but are incurred on behalf of the Company as a whole. Examples include capitalized credits to O&M, billing credits for Administrative and General ("A&G") labor, expenses, and outside services as part of a full-cost loading adder, and senior management time and expenses; and

- Administrative and Other – These costs are primarily for American Gas Association dues and intervenor funding.

**Q. How are Corporate Services expenses allocated between the Company's electric and gas businesses?**

A. Allocations are developed based upon the type of cost. For example, billing costs are allocated based on customer counts for the electric and gas business, benefits are allocated based on either employee counts or labor, general costs are allocated based on the Three Factor Allocation Method, with other costs being directly charged for identified activities, allocated based on capital and O&M spending levels and special studies.

**Q. What is the Three Factor Allocation Method?**

A. The Three Factor Allocation Method uses the average of three factors (Operating Revenue, Labor and Property, and Plant and Investments) to allocate costs between the electric and gas businesses.

**Q. Explain how the Adjusted Corporate Services O&M was calculated.**

A. Exhibit A-44 (MJF-2), line 12, provides the Company's gas portion of total Corporate Services expenses, before adjustments. The 2023 actual O&M expenses were obtained from the Company's records. Specific line-item changes are included as increases or decreases as appropriate to reflect exclusions, remove one-time costs, reflect transfers of costs into or out of the Corporate Services area, or reflect significant ongoing changes in Corporate Services O&M expense. Exhibit A-44 (MJF-2), line 15, column (d), shows the total normalizations of one-time costs from 2023 total Corporate Services expense. The 2023 Voluntary Separation Program costs and One-time Consultant Expenses were removed in the normalizations line. Also, the total of items disallowed by Commission order related to advertising, lobbying, and donation payments were removed on Exhibit A-44 (MJF-2), line 18. Total adjusted Corporate Services expense is found on Exhibit A-44 (MJF-2), line 19.

**Q. What is the projected rate of inflation?**

A. The assumed rate of inflation is based on the Consumer Price Index ("CPI") which considers factors specific to pricing of goods and services, such as the cost of food, energy, and housing. The CPI is 3.2% for 2024, 2.4% for 2025, and 2.5% for 2026. Consumers Energy uses these inflation rates to project Corporate Services O&M.

**Q. What is the source for the CPI?**

A. The June 2024 edition of the IHS Markit U.S. Economic Outlook. Company witness Heather L. Rayl supports the inflation rates.

**Q. In addition to increases related to inflation, what other specific line-item changes are included to arrive at the test year O&M expense projection?**

A. Exhibit A-44 (MJF-2), column (m) includes three line-item changes resulting in a $2,366,000 reduction to the projected test year for organizational efficiencies.

**Q. Please describe in detail the specific line item changes included in Exhibit A-44 (MJF-2), column (m) related to efficiencies.**

A. Exhibit A-44 (MJF-2), column (m) includes adjustments of ($2,366,000) for labor efficiencies. The reduction of ($2,366,000) to the labor projection is based on an anticipated decrease in headcount as a result of business process optimization initiatives. The labor adjustments were made to four areas included in Corporate Services. Exhibit A-44 (MJF-2), column (m), line 2, includes an adjustment of ($263,000) for Sustainability & External Affairs. Exhibit A-44 (MJF-2), column (m), line 3, includes an adjustment of ($507,000) for Legal, Ethics, Regulatory, and Risk. Exhibit A-44 (MJF-2), column (m), line 4, includes an adjustment of ($505,000) for People & Culture. Exhibit A-44 (MJF-2), column (m), line 5, includes an adjustment of ($1,091,000) for Finance and Shared Services.

**Q. Are the costs associated with restricted stock and the Employee Incentive Compensation Program ("EICP") included in the 2023 actuals or projected Corporate Services O&M expense?**

A. No. Further details regarding restricted stock and EICP expenses are covered under the direct testimony of Company witness Amy M. Conrad.

**Q. Is the level of test year Corporate Services O&M expense reasonable?**

A. Yes. The reasonableness of the O&M expense levels is supported by the fact that Standard and Poor's ("S&P") Global Market Intelligence ranked Consumers Energy's 2023 gas A&G costs (excluding pension and benefits) the second lowest out of the 27 top companies ranked on a cost per customer basis for gas utility companies with more than 500,000 customers. The Company's ranking by S&P Global Market Intelligence in this regard indicates the Company's diligence in managing overhead costs. Please refer to Exhibit A-53 (MJF-11) for the report on this ranking.

**Q. What is S&P Global Market Intelligence?**

A. S&P Global Market Intelligence provides financial and operating data for gas and electric utility companies.

**Gas Uncollectible Expense**

**Q. How did the Company determine the uncollectible expense included in the test year?**

A. The Company projects the uncollectible accounts expense for the test year at $15,327,427 as shown on Exhibit A-45 (MJF-3), page 1, column (e). The projected test year uncollectible accounts expense is based on a three-year historical average Bad Debt Loss Ratio ("BDLR") of uncollectible accounts expense to gas service revenue for the years 2021 through 2023, as shown on Exhibit A-45 (MJF-3), page 2. This ratio is applied

to the test year gas service revenue, plus energy waste reduction surcharge revenue, to arrive at test year uncollectible accounts expense on Exhibit A-45 (MJF-3), page 1, line 1, column (e).

**Q. Does the estimate of test year uncollectible accounts expense consider changing natural gas prices, their impact on customer bills, and the corresponding impact on uncollectible accounts expense?**

A. Yes. By using the test year revenues in the calculation, the latest gas commodity cost projections are taken into account.

**Q. Does this method provide a reasonable estimate of uncollectible expense?**

A. Yes. The Company continuously strives to reduce uncollectible accounts expense. However, year-over-year, uncollectible accounts expense can be impacted by many factors. The economy, the effectiveness of collection practices, funding of low-income assistance programs, extreme weather fluctuations, or any number of other factors that could impact customers' ability to pay. As a result, the Company is proposing a three-year average BDLR from 2021 through 2023 in this rate case filing. This method most effectively captures the recent trends of the many factors that can impact uncollectible accounts expenses.

**Q. What mitigation strategies has the Company used to manage uncollectible expense?**

A. Over the last several years, the Company has implemented several mitigation strategies serving to reduce uncollectible expense. First, turn on compliance was implemented to stop the cycle of carrying a past-due balance to a newly opened account. Processes were put in place that required customers with an unpaid balance to pay the old balance in full, prior to opening a new utility account. Second, the Company prioritized collection

activities on high risk and high volume past due accounts to reduce the overall Company arrears balance. In addition, the implementation of smart meters has helped to reduce uncollectible expense through automated turn-off capability.

**Gas Injuries and Damages Expense**

**Q. Please describe Exhibit A-46 (MJF-4).**

A. Exhibit A-46 (MJF-4) summarizes the Company's total 2019 through 2023 actual gas injuries and damages expense and projected injuries and damages expense through the 12 months ending October 31, 2026.

**Q. Please describe the costs related to injuries and damages.**

A. Gas injuries and damages include liabilities that arise in the normal course of Company business for various types of items such as compensation for damaged trees and crops; restoration of driveways, lawns, and fences; and accidents and lawsuits that are below the various insurance deductibles or are otherwise uninsurable events. Further, workers' compensation costs are included in injuries and damages along with associated internal legal costs.

**Q. What expense level is the Company proposing to recover in this case as part of the test year?**

A. The Company is proposing that a total of $2,279,205 be included for the test year as shown on Exhibit A-46 (MJF-4), line 4, column (i).

**Q. How was this amount determined?**

A. The injuries and damages expense is comprised of three components: gas injuries and damages, internal legal costs, and workers' compensation costs. Exhibit A-46 (MJF-4), line 1, reflects the gas property and liability damages. Line 2 represents the amount of

internal legal costs that are charged to injuries and damages. Line 3 represents the level of workers' compensation costs for each year. The test year amounts for each of the three components of total injuries and damages expense is based on a five-year average of actual expense for the years 2019 through 2023.

**MGP Site Remediation and Direct Project Management Costs**

**Q. How did the Commission previously address environmental investigation and remediation expenditures at former MGP sites?**

A. In Case No. U-10755, the Commission approved deferred accounting for these expenditures, with amortization over 10 years, beginning the year after expenditures are incurred. The approach adopted by the Commission envisioned that prudence reviews would occur in rate cases and that following a prudence review: (i) the amortization expense would be included in rates; and (ii) the deferred balance would be included in rate base and would earn a return at the authorized rate of return. The approach adopted by the Commission also provided for deferred accounting and amortization of third-party recoveries in excess of the costs of recovery over 10 years, the inclusion of the unamortized balance in rate base, and deferred tax accounting. In Case No. U-13000, the Commission upheld this accounting treatment.

**Q. Please explain Exhibit A-47 (MJF-5), page 1, line 1, which provides deferred cash expenditures for MGP remediation costs.**

A. Line 1 shows deferred cash expenditures for MGP remediation costs for years 2005 through 2023 and projected expenditures through December 31, 2024.

**Q. Why are you including projected expenditures through December 31, 2024 and not through the projected test year ending October 31, 2026?**

A. I am including projected expenditures through December 31, 2024 to reflect an estimate of actual expenditures that will be available for review by MPSC Staff ("Staff") during this case. Actual expenditures available through the date of Staff's review will be made available at that time.

**Q Please explain the remainder of Exhibit A-XX (MJF-5), page 1.**

A. Line 2 shows the third-party insurance recoveries for the years 2005 through 2023 and projected recoveries through December 31, 2024. Lines 3 through 22 show the annual amortization of these deferred MGP remediation costs using a 10-year amortization period. Amortization of the third-party recoveries on line 2 is shown on line 22 and acts as a credit to the amortization of expenditures identified in this case. Line 23 is the net MGP amortization expense. It should be noted that until these expenditures are incorporated in a future order, the Company is required to absorb the associated carrying cost and amortization of these costs. Net amortization expense on Exhibit A-47 (MJF-5), page 1, line 23, is included in Exhibit A-13 (HLR-43), Schedule C-6, of Company witness Rayl.

**Q. Please explain Exhibit A-47 (MJF-5), page 1, line 24.**

A. Line 24 is the project management costs that the Commission provided for recovery as direct costs rather than deferred and amortized costs as part of its Order in Case No. U-14547. The change became effective for the calendar year 2006 onward. These costs are carried forward to line 4 of Exhibit A-43 (MJF-1).

**Q. Please explain Exhibit A-47 (MJF-5), page 2, related to the rate base treatment of the MGP unamortized balance.**

A. Exhibit A-47 (MJF-5), page 2, provides the net unamortized balance of actual deferred MGP remediation costs and third-party recoveries for the years 2005 through 2023 and projected balances for the year 2024. Column (b) reflects the average unamortized balance to be included in rate base for the test year. Columns (c) and (d) reflect the year-end balances for the 12 months ending October 31, 2025 and 12 months ending October 31, 2026. Column (e) reflects the original costs of the deferred expenditures and third-party recoveries by year.

**Q. What ratemaking treatment is the Company proposing in this proceeding for MGP environmental costs?**

A. The Company is requesting that the Commission: (i) find that the costs sponsored by Company witness Heather M. Prentice, are reasonable and prudent; (ii) authorize recovery of amortization expense in the amount of $7.3 million as provided on Exhibit A-47 (MJF-5), page 1; (iii) approve test year direct project management costs of $0.9 million as provided on Exhibit A-47 (MJF-5), page 1; and (iv) include the deferred net unamortized balance in the amount of $20.0 million in rate base as provided on Exhibit A-47 (MJF-5), page 2.

**PART 2 – GAS CORPORATE SERVICES CAPITAL EXPENDITURE**

**Q. Please describe Exhibit A-12 (MJF-12), Schedule B-5.4.**

A. Exhibit A-12 (MJF-12), Schedule B-5.4, summarizes the Company's total 2023 through the 12 months ending October 31, 2026, gas capital expenditures for Corporate Services. Column (a) of this exhibit provides the description; column (b) provides the 2023 actual

capital; column (c) provides the projected 2024 capital; column (d) provides the projected ten months ending October 31, 2025 capital; column (e) provides the projected 22 months ending October 31, 2025 capital; and column (f) provides the projected test year 12 months ending October 31, 2026 capital of $238,000. Categories of expenses include costs to equip and support Corporate Services areas primarily at Company headquarter locations with office furniture and equipment.

**Q. Please explain how the projected Corporate Services Capital expense was calculated.**

A. The 2023 actual Capital expenses were obtained from the Company's records and subsequent costs were projected using inflation rates.

**PART 3 – CORPORATE TECHNOLOGY PROJECTS**

**Q. Is the Company planning technology projects that support the Corporate Services functions?**

A. Yes. Company witness Stacy H. Baker includes, in her direct testimony and exhibits, five technology projects that are critically important in enabling the Company's Corporate Services functions to support the Gas business in a safe, effective, efficient, and compliant manner. These projects are described below:

- The **2025 Union Contract Changes** project requires $105,726 in O&M in the test year.

  **Description:** The 2025 Union Contract Changes project will implement SAP and other system changes required as a result of three collective bargaining agreements which will be renegotiated and ratified. Collective bargaining agreements expire every five years for Operating Maintenance and Construction ("OM&C"), Virtual Contact Center ("VCC"), and Zeeland employee groups. For OM&C, the current agreement ends June 1, 2025. The VCC agreement ends August 1, 2025. The Zeeland agreement ends October 1, 2025.

  **Problem Statement:** Collective bargaining agreements expire every five years for OM&C, CCC ("Customer Contact Center") and Zeeland employee groups.

For OM&C, the current agreement ends June 1, 2025. CCC agreement ends in August 1, 2025. Zeeland agreement ends October 1, 2025. Technology changes are required to reflect these new agreements. Otherwise, employees in these union groups may not be paid appropriately or get correct benefits.

**Objectives:** Completion of this project will provide value to the Company and its customers through: (1) waste elimination by making changes in the software for any pay and benefit changes as required by the new agreements; (2) defect reduction by adding process automation to otherwise manual processes for tracking and recording work, premium, and absence time; and (3) improved employee engagement among the OM&C, CCC, and Zeeland union employees.

**Scope:** The scope of this project encompasses making any system changes required to support the new working agreement for the OM&C, CCC, and Zeeland employees. Exact details will be finalized after the negotiation process is completed and contracts are approved.

**Alternatives:** Three alternatives were considered for this project: (1) Make no system changes after the contracts are ratified. This option was not chosen because it exposes the Company to possible fines, disengaged employees, union grievances, significant manual processes leading to greater possibility of error, hiring additional staff to perform activities outlined in the agreements, and increased legal costs due to employee grievances. (2) Find other third-party software to support the changes required by the union agreements. This option was not chosen because it would require SAP integration along with additional software licensing and maintenance costs. (3) Make system changes to eliminate manual updating, comply with the working agreement language, support union employee engagement, and reduce grievances. Option (3) was chosen because it leverages current SAP technology, automates what would otherwise require manual processing, and is the least costly option.

- The **Expense Reporting Improvements** project requires $123,499 in capital and $43,532 in O&M in the test year.

**Description:** The Expense Reporting Improvements project will increase productivity when creating expense reports; leverage workflows for expense processing and exceptions; improve adherence to Company policies; provide insights through improved reporting; and minimize human intervention and struggle throughout the expense process.

**Problem Statement:** Multiple problems exist with our current expense reporting system in the areas of usability, employee engagement, inefficiencies, compliance, and audit exceptions. Submitting expense reports is not intuitive, leading to errors and the need for manual intervention. In addition, employees have to manually scan and attach receipts. All these problems impact employees leading to poor employee engagement scores in regards to simple

processes, productivity, and transparency leading to increased costs, inefficiencies, exceptions to policies, and compliance issues. An average of 13% of all expense reports have compliance errors, based on a sample audit of executive assistant submitted expense reports.

**Objectives:** This project provides value for the Company by: (1) improving expense policy compliance and reducing exceptions, with a target measure of 0 compliance errors; and (2) offering a more user-friendly experience leading to improved employee engagement. Completion of these objectives would enable each employee to save 20 minutes creating an expense report for each of the 50,175 expense reports created in 2021, the Company would have avoided approximately $1.5 million of costs, based on a $90/hr. average rate.

**Scope:** The project scope includes implementing a new software tool that: (1) provides upfront validation and controls to improve policy compliance; (2) provides electronic document retention for receipts; and (3) integrates corporate credit card data into expense reports.

**Alternatives:** Three alternatives were considered for the project: (1) continue using the current solution; (2) choose a cloud-based solution with the expense reporting component; and (3) develop a custom front-end. The first alternative would result in waste due to the system not being user-friendly; and does not provide mobile options. The second alternative would introduce new licensing and ongoing maintenance costs; would require periodic upgrades and testing; and would require the SAP Enterprise Portal to be upgraded to integrate with the booking tool. The third alternative and selected option would result in improved user experience and employee engagement as well as mobile capabilities around expense entry.

- The **Talent Management Enablement** project requires $23,095 in capital and $5,950 in O&M in the test year.

**Description:** The project will deliver technology solutions to enable best-in-class Talent Management programs and processes that are critical to achieve the Company's overarching Talent Strategy Plan. The Talent Strategy Plan is a key enabler of the Company's Integrated Resource Plan (IRP), Electric Distribution Infrastructure Investment Plan (EDIIP), and Natural Gas Delivery Plan (NGDP). Effective Talent Management programs and processes are critical to develop the skills, capabilities, productivity, and experience necessary to successfully execute these plans that deliver clean, reliable, affordable energy through an exceptional customer experience.

**Problem Statement:** Significant technology improvements are required to transform Human Resources ("HR") to develop the skills and capabilities necessary to achieve the Company's strategic destination. Currently, many Talent Management processes are manually managed with little or no

technology enablement. Specifically, the talent compensation processes are mostly manually done outside the system which introduces waste, and a potential for errors. In addition there is a limited visibility of competency gaps within the workforce. The Company cannot effectively place talent in accelerated development programs aligned to competency gaps, nor can it recognize and motivate employees for quickly increasing competency and performance. Furthermore, the Company operates in an increasingly competitive job market where candidates and employees expect best-in-class processes, technologies and experiences relative to their employment and career development. The lack of full technical enablement across Talent Management programs poses a risk to employee attraction, retention and limits the ability to develop the right skills at the right time to deliver on Company strategies.

**Objectives:** This project will add value to the Company through technology that will enable: (1) fully functional integrated compensation module; (2) accelerated and targeted talent development of critical skills necessary to deliver on the Company's commitment to clean energy and exceptional customer experience; (3) transparency into talent and skill gaps in order to identify retention and service delivery risks within critical areas, as well as inform succession and hiring strategies; (4) improved knowledge transfer, business continuity, and customer service during a time when retirement eligibility is high and risk of knowledge loss has the potential to negatively impact customer service and satisfaction; and (5) increased efficiency and quality of talent management through simplified and automated processes that reduce costs associated with recruiting, onboarding, and developing employees. Talent Management Enablement will deliver the best-practice technology to enable and enhance: (1) Fully functional integrated talent compensation management; (2) Simplified and automated talent management process for employee lifecycle management from on-boarding through off-boarding; (3) Succession Planning and Business Continuity; and (4) Career Development and Employee Retention.

**Scope:** The scope will include: (1) implementation of each system/application; (2) integration with current systems, applications and processes as applicable; (3) retrofit current systems and applications to ensure a seamless end-to-end experience of HR processes; (4) delivery of mobile capabilities for in scope processes; (5) reporting and analytics dashboards and report insights for in scope processes.

**Alternatives:** Three alternatives were considered for these Talent Management programs and processes: (1) Develop custom, internally built solutions that could meet most requirements. This alternative was not selected because a custom solution would result in higher overall costs, higher maintenance costs, fewer upgrades, and would not leverage industry best practices to ensure best-in-class delivery. (2) Select an on-premise software tool. This alternative was not selected because it requires internal maintenance, increases infrastructure

costs, and would have less frequent upgrades which would hinder the Company's ability to ensure processes are evolving alongside industry trends and best practices. (3) Evaluate and select cloud/SaaS solution(s) which would have lower infrastructure costs, less internal maintenance than an on-premise solution, and would be built and evolved with upgrades based on industry best practices. Based on research, internal experience with successful best practice implementations, and vendor demonstrations, option three was selected.

- The **Enterprise Risk Management** project requires $26,423 in O&M in the test year.

**Problem Statement:** The Enterprise Risk Team (ERT) works with Risk Owners (RO) on an annual basis to identify new risks, update existing risks, quantify impacts and likelihoods of these risks, document mitigation plans, identify trends, and formulate risk tolerance metrics. This work is accomplished through an iterative back-and-forth process between ERT and ROs to gain alignment on content. This effort culminates in multiple Risk Map PowerPoint, Microsoft Word and email documents organized by area of risk. These risk maps are then presented to senior management and to the Board of Directors (BoD) on an annual basis. The intensive, time-consuming manual Enterprise Risk Management (ERM) process creates risks of human error that can over or under quantify risks, introduce data anomalies, and create version tracking issues. The existing process results in substantial inefficient use of time by risk analysts and risk owners throughout the Company, limits the breadth of analysis that can be provided, and limits the overall ability of the Company to timely identify, analyze, and communicate risks to our senior leaders, thereby causing potential delays in responding to emerging risks. Because of the lengthy manual process, it is only performed once a year, but must be performed more frequently to proactively manage enterprise risk. Utility industry peers leverage software to more effectively manage enterprise risk management programs.

**Objectives:** This project creates value for the Company by: (1) providing real-time risk information to interested parties including the risk team, risk owners, senior management, and the Board of Directors (BoD) supporting proactive risk management; (2) creating a centralized repository for risk identification, management, and mitigation plans; (3) eliminating waste by simplifying processes; and (4) improving efficiency of the risk owners and analysts.

**Scope:** The scope of the project includes: (1) create risk analysis templates and tools for automated reporting; (2) configure automated workflow to perform risk updates; (3) configure dynamic templates that prompt the risk owners based on prior selections; (4) organize risk assessments through an online and searchable data capture (repository); (5) create new reports and executive dashboards; (6) data conversion; and (7) set record retention rules.

**Alternatives:** Alternatives considered include: (1) Continue use of the current manual processes which result in waste, lack of quality results, and annual review of risks; (2) Build a custom internal enterprise risk solution. This option was not selected as it will not result in an enterprise risk program that leverages best practices that exist in software provided by the leaders in risk management software; and (3) Implement a software solution from a leading enterprise risk solution vendor. While this would introduce new license and ongoing support costs, it is the preferred option because it leverages industry best practices with a proven solution; provides application reliability, security, and stability through ongoing vendor support; and brings innovation and insights via the reporting of risk information through management dashboards. In addition, it aligns the Company with utility industry peer practices for more effective enterprise risk management.

- The **Self Service Vendor Portal** project requires $28,248 in capital and $39,811 in O&M in the test year.

**Description:** The work will create an external portal for vendors to exercise self-service features to streamline and automate purchase order and invoice management and improve visibility to invoice and payment status.

**Problem Statement:** For Accounts Payable, vendors must repeatedly interact with the Company through multiple channels to ask questions, submit invoices, or check invoice or payment status, including email, physical mail, or the phone. Once a request is submitted, additional calls, emails, or Company portal requests are required for status updates, to make payments, or to respond to missed contacts. The existing service portal has functionality limited to incoming vendor inquiries only and lacks self-service options for vendor invoice and payment management and lacks the ability for vendors to utilize touchless invoice creation from POs. The limitations of the existing portal result in waste and inefficiencies for vendors and Company employees/contractors, which currently includes 6 contracted resources, and creates the potential for late payments or missing early payment discounts. For Supply Chain, vendors must repeatedly interact with the Company through multiple channels to ask questions, update POs (quantities, costs, shipping dates) including email, physical mail, or the phone. Once a request is submitted, additional calls, emails, or Company portal requests are required for status updates or to respond to missed contacts. The existing service portal has functionality limited to incoming vendor inquiries only and lacks self-service options for updates to the POs. The limitations of the existing portal result in waste and inefficiencies for vendors and Company employees/contractors, which currently includes 4 employee resources. This also creates the potential for late payments, missing early payment discounts, delays in receiving due to lack of shipping notifications from vendors, delays to scheduled work due to lack of acknowledgement and lead time adherence, and the inability to enforce contractual obligations.

**Objectives:** This project creates value for the Company by: (1) creating self-service functionality/increasing touchless invoice creation/processing that allows the vendor to select items from a purchase order to create an invoice on demand; (2) providing vendors with real-time invoice and payment status, increasing employee productivity by eliminating waste (3) allow self-service updates of vendor master data (banking info, remittance info, etc.) (4) fewer late payments by vendors thus reducing Company follow up and tracking; (5) creating better visibility for vendors to take advantage of early payment discounts thus reducing related vendor inquiries; (6) reducing vendor questions related to invoice and purchase orders through self-service functions and portal information; (7) reducing the cost per invoice; (8) creating self-service functionality/increasing touchless PO creation/processing that allows the vendor to select items from a purchase order to update quantities, costs, and shipping dates; (9) providing vendors with real-time PO information, increasing employee productivity by eliminating waste; and (10) fewer late deliveries by vendors thus reducing Company follow up and tracking.

**Scope:** The project scope includes: (1) submit an RFP for a vendor portal solution and implementation; (2) configure ability for vendors to more efficiently and more accurately self-submit invoices and POs electronically; (3) configure ability for vendors to self-convert items on a purchase order to an invoice; (4) configure ability for vendors to view invoice and payment status; (5) configure ability for vendors to make changes to SAP master data, including PO line item details; (6) configure ability to offer/process dynamic discounting (7) create new reports and dashboards; (8) enabling method to validate vendors should have access to the portal and removing access when appropriate; (9) configure ability for vendors to make self-serve changes to shipping status and delivery dates; and (10) integration to vendor invoice management system and SAP.

**Alternatives:** Alternatives considered include: (1) Continue use of the current manual processes which results in waste and inefficiencies for employees and vendors. This could also result in late payments and lost discounts for vendors; (2) Build a custom solution. This option was not selected as the Company has a vendor portal, that is only leveraged for vendors to ask questions. As well, it doesn't leverage best practices; (3) Building a combination of custom and standard integration to existing solutions. This option was not selected because it doesn't follow industry best practices; (4) expand our current vendor portal. This option was not chosen due to limited functionality and not matching capability roadmaps; and (5) implement a new SaaS solution specific to a vendor portal experience. Option (5) is the preferred option because it leverages industry best practices with a proven solution; provides application reliability,

security, and stability through ongoing vendor support; and brings innovation to vendors via real-time processing.

**PART 4 – ACCOUNTING REQUESTS**

**DB Pension/OPEB Volatility Mechanism**

**Q. Does the implementation of the DB Pension/OPEB Volatility Mechanism, discussed in Company witness Kendra K. Grob's direct testimony, require any specific accounting approvals?**

A. Yes. The mechanism would result in deferred debits or credits until balances are fully amortized over 10 years. The Company requests approval to continue recognizing regulatory assets or liabilities as needed to record these deferred amounts as approved in the settlement agreement in Gas Rate Case No. U-21308.

**Q. Does the anticipated Leak Detection and Repair Regulations ("LDAR"), discussed in the direct testimony of Company witnesses James P. Pnacek and Kristine A. Pascarello, require any specific accounting approvals?**

A. Yes. The requested deferral of O&M expense and the revenue requirement of capital spending associated with LDAR costs above amounts included in rates could result in the recording of deferred debits.

**Q. Does the volatility in staking program demand, discussed in Company witness Pnacek's direct testimony, require any specific accounting approvals?**

A. Yes. The mechanism would result in deferred debits or credits for test year O&M as discussed on page 48 of Company witness Pnacek's direct testimony.

**PART 5 – AFFILIATED COMPANY TRANSACTIONS**

**Q. What is the purpose of your direct testimony with respect to Affiliated Company Transactions?**

A. I am sponsoring Exhibits A-48 (MJF-6), A-49 (MJF-7), and A-50 (MJF-8) to comply with the filing requirements for gas rate cases before the Commission, as clarified in Case No. U-10039. I am also sponsoring two additional exhibits, Exhibits A-51 (MJF-9) and A-52 (MJF-10), as described below.

**Q. Please explain Exhibit A-48 (MJF-6).**

A. Page 1 of this exhibit provides an organizational chart showing the interrelationship of the affiliated companies that had transactions with Consumers Energy relative to providing/receiving services or commodities. In addition, pages 2 and 3 list their affiliation, percentage ownership, and purpose of business.

**Q. Please explain Exhibit A-49 (MJF-7).**

A. This exhibit summarizes costs billed to affiliated companies, page 1, and payments made to affiliated companies, page 2, for the year 2023.

**Costs Billed to Affiliated Companies**

**Q. For the costs billed to affiliated companies, how are the costs classified and how are they priced?**

A. These costs are classified as to whether they impact the balance sheet, other operating income, or utility operating income. These costs are all priced on a full-cost basis.

**Q. What is meant by "costs are all priced on a full-cost basis"?**

A. The full-cost basis means total direct costs along with applicable overheads. For services provided, it would be primarily labor costs incurred along with allocated overheads and

employee benefits. For commodities purchased, it would be the contracted amount for the commodity based on a negotiated purchase by the Gas Supply organization or, on the electric side, the Electric Supply organization. Property leased is priced per contract.

**Q. For commodity purchases, what is the difference between the full-cost amount and market amount?**

A. At the time of the purchase, the full-cost amount and market amount would be the same. In other words, it is the agreed upon price between the purchaser and seller of the commodity.

**Q. Please describe the types of services performed by Consumers Energy for affiliated companies.**

A. Most services performed are administrative services such as payroll, corporate communications, human resources, and computer services; employee benefits related to health care, life insurance, and savings plan; or professional services such as engineering, accounting, legal, and tax.

**Q. What types of billing activity are directly classified to the balance sheet?**

A. These are the direct costs incurred for employee benefits or for rendering services to affiliated companies that are separately accounted for in Consumers Energy's accounting system and translate to an individualized receivable from the associated company (Account 146).

**Q. What types of billing activity are classified as other operating income?**

A. Billing activity classified as other operating income consists of income related to the cost of money.

**Q. Please explain the cost of money.**

A. The cost of money is the recovery of Consumers Energy's cost for the use of its funds expended to render services prior to reimbursement. This recovery is recorded in Account 419, Interest Income.

**Q. What types of billing activity are classified as utility operating income?**

A. Billing activity classified as utility operating income consists of overhead costs. These costs affect A&G expenses and revenue accounts.

**Q. What is the impact of this utility operating income activity on gas operations?**

A. As shown on Exhibit A-50 (MJF-8), gas operations were favorably impacted by $587,986.

**Payments Made to Affiliated Companies**

**Q. Please describe the types of goods provided by affiliates and services performed for Consumers Energy as shown on Exhibit A-49 (MJF-7), page 2.**

A. Services provided include officer services and professional services, such as accounting, engineering, finance, legal, energy purchases, and tax.

**Q. For payments made to affiliated companies, how are they classified and how are they priced?**

A. These payments are classified as to whether they impact the balance sheet, other operating income, or utility operating income. These payments are priced on a full-cost basis.

**Q. What types of payment activity are classified as balance sheet items?**

A. The payments classified as balance sheet items consist of costs deferred on the balance sheet for subsequent reclassification, amounts to be billed, or amounts recorded as liabilities.

**Q. What types of payments are classified as utility and other operating income?**

A. Payments consist generally of CMS Energy Corporation costs for restricted stock, energy purchases, and professional services.

**Q. Is the Massachusetts Formula method used to allocate administrative costs of the parent company to Consumers Energy?**

A. Yes. The Massachusetts Formula is used to allocate certain parent company indirect costs to its subsidiaries, which includes Consumers Energy.

**Q. Why is the Massachusetts Formula method used to allocate costs?**

A. This method is used to allocate indirect costs that cannot be readily identified to any particular subsidiary or affiliated company.

**Q. How long has the Massachusetts Formula been used to allocate costs?**

A. This allocation method has been used to allocate costs within CMS Energy Corporation since 1987.

**Q. Are parent company costs that can be identified to Consumers Energy charged directly to Consumers Energy?**

A. Yes. When the costs can be specifically attributed to Consumers Energy, these costs are charged directly to Consumers Energy.

**Q. Why is the Massachusetts Formula method an appropriate allocation method for certain Company costs?**

A. This method provides a practical means to allocate a pool of common costs based on an equitable and consistent basis. Subjectivity and inability to directly charge costs is the reason the Massachusetts Formula is utilized by entities to allocate costs.

**Q. Did Consumers Energy develop the Massachusetts Formula?**

A. No. It was first conceived as a method for state tax administration in Massachusetts. Subsequently, the formula was adopted for allocating A&G expense in diversified corporations.

**Q. Has FERC approved the use of the Massachusetts Formula?**

A. Yes. Examples of specific companies that have used this method include: Duke Energy, Entergy Services, Inc., San Diego Gas & Electric, and Williams Natural Gas Company.

**Q. What is the impact of payments classified as utility operating income on gas operations?**

A. The amount of payments applicable to gas operations for these activities in 2023 is $3,174 as shown on Exhibit A-51 (MJF-9).

**Q. Please explain Exhibit A-52 (MJF-10).**

A. This exhibit shows the rate of return on common equity for the affiliates doing business with Consumers Energy.

**Q. Is Consumers Energy in compliance with the guidelines for intercompany transactions between affiliates as ordered by the Commission in Case No. U-18361?**

A. To the best of my knowledge, Consumers Energy is in compliance with these guidelines.

**Q. Does this conclude your direct testimony?**

A. Yes.

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

| | | |
|---|---|---|
| In the matter of the application of<br>**CONSUMERS ENERGY COMPANY**<br>for authority to increase its rates for the<br>distribution of natural gas and for other relief. | )<br>)<br>)<br>)<br>) | Case No. U-21806 |

# REBUTTAL TESTIMONY

# OF

# MATTHEW J. FOSTER

# ON BEHALF OF

# CONSUMERS ENERGY COMPANY

May 2025

**Q. Please state your name and business address.**

A. My name is Matthew J. Foster, and my business address is One Energy Plaza, Jackson, Michigan 49201.

**Q. Are you the same Matthew J. Foster who previously presented direct testimony in this case on behalf of Consumers Energy Company ("Consumers Energy" or the "Company")?**

A. Yes.

**Q. What is the purpose of your rebuttal testimony?**

A. The purpose of my rebuttal testimony is to respond to the Attorney General's ("AG") proposed adjustment to Corporate Services operating and maintenance ("O&M") Expense and the Michigan Public Service Commission ("MPSC" or the "Commission") Staff's ("Staff") update to Unamortized Manufactured Gas Plant ("MGP") and MGP Amortization Expense.

**Q. Have you prepared any exhibits in conjunction with your rebuttal testimony?**

A. Yes, I prepared the following exhibit:

Exhibit A-134 (MJF-13) Gas General Activities Labor Expense.

**Q. What adjustments did the AG propose to the Corporate Services Expense?**

A. As shown in pages 183 through 184 of his direct testimony, AG witness Sebastian Coppola recommends a reduction of $10,910,000 to the Company's requested Corporate Services O&M projection of $26,874,473. Mr. Coppola calculated the proposed adjustment by using the 2024 General Activities Labor ("General Activities") plus inflation to calculate the forecasted amount for the projected test year.

**Q. What is the AG's reasoning for the proposed adjustment to Corporate Services O&M?**

A. Starting on line 2, page 183, of Mr. Coppola's testimony, he describes the 2023 General Activities as being "unusual and excessive" as a result of the 2023 expense being larger than recent years.

**Q. Does the Company agree with the AG's proposed adjustment to the Corporate Services O&M related to General Activities?**

A. No, the Company does not agree with the proposed adjustment. In 2023, General Activities included Voluntary Separation Program ("VSP") expenses of $12.6 million and Employee Incentive Compensation Program ("EICP") expenses of $7.8 million. The Company removed both expenses from the Corporate projected test year O&M as VSP is a non-recurring event and EICP is covered under the direct testimony of Company witness Amy M. Conrad. Per Exhibit A-134 (MJF-13), when excluding these expenses, the adjusted 2023 General Activities is a credit balance of $13.0 million, which is consistent with prior years. Therefore, the projected test year balance of General Activities is in no way "unusual and excessive" as stated by the AG.

**Q. Please describe Exhibit A-134 (MJF-13).**

A. Exhibit A-134 (MJF-13) reports the expenses included in General Activities. The expense components include Senior Officer Expense, Capitalized Credits, Billing Credits, EICP, VSP, and other miscellaneous expenses.

**Q. Please explain why the General Activities has fluctuated in recent years.**

A. As shown in Exhibit A-134 (MJF-13), VSP expense included on line 5 and EICP expense included on line 4 are the primary reasons for the fluctuation in General Activities in recent

years. As previously stated, when excluding these expenses, the remaining cost components in General Activities have been reasonably consistent.

**Q. Please explain line 8 from Exhibit A-134 (MJF-13).**

A. Exhibit A-134 (MJF-13), line 8, calculates Total General Activities less VSP and less EICP expenses. The General Activities calculation, normalizing for VSP and EICP expenses, results in negative expense (credit) of approximately $12 to $13 million in recent years. Line 8 validates that VSP and EICP expense components, which the Company has removed from the projected test year, are driving the General Activities fluctuations noted by the AG as being "unusual."

**Q. Does the Company agree with the Staff's adjustments to the Unamortized MGP balance and the test year projection of MGP amortization expense?**

A. Yes. The Company agrees with the adjustments proposed by Staff.

**Q. Does this conclude your rebuttal testimony?**

A. Yes.

MR. RUSZKIEWICZ: Company's next witness is Samuel M. Geller. Based on stipulation of the parties, the Company moves to bind in the direct testimony of Mr. Geller, consisting of a cover page and 15 pages of prefiled testimony. Mr. Geller also had rebuttal testimony in the form of a cover page, plus 6 pages of prefiled testimony.

The Company also moves to admit the exhibits of Mr. Geller, which consist of A-16 Schedule F-1, A-16 Schedule F-1.1, A-54, A-55, A-56, and A-57.

JUDGE VARCHETTI: All right. Are there any objections to the admission of Mr. Geller's direct or rebuttal testimony or any of the associated exhibits?

Hearing none, then, the testimony is bound into the record, and the exhibits are admitted.

MR. RUSZKIEWICZ: Thank you, Your Honor.

(Direct and Rebuttal Testimony bound in)

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

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|---|---|---|
| In the matter of the application of<br>**CONSUMERS ENERGY COMPANY**<br>for authority to increase its rates for the<br>distribution of natural gas and for other relief. | )<br>)<br>)<br>)<br>) | Case No. U-21806 |

**DIRECT TESTIMONY**

**OF**

**SAMUEL M. GELLER**

**ON BEHALF OF**

**CONSUMERS ENERGY COMPANY**

December 2024

**INTRODUCTION**

**Q. Please state your name and business address.**

A. My name is Samuel M. Geller, and my business address is One Energy Plaza, Jackson, Michigan 49201.

**Q. By whom are you employed and in what capacity?**

A. I am employed by Consumers Energy Company ("Consumers Energy" or the "Company") as a Principal Rate Analyst in Regulatory Policy and Research.

**Q. Please describe your educational background.**

A. I received a Bachelor of Arts degree in American Cultural Studies in May 2009 from Bates College as well as a Master of Public Policy from the Gerald R. Ford School at the University of Michigan in December 2017.

**Q. What is your professional experience?**

A. After earning my Bachelor's degree, I worked in the nonprofit sector and served as a finance staff member on political campaigns for US Congress, Governor, and City Council. During my graduate education, I served as a Co-Op Student with the Corporate and Government Affairs team at DTE Energy in Detroit which served as my introduction to the utility industry. From 2018 to 2021, I worked for the city of Detroit Mayor's office first as a Project Manager and Analytics Specialist and later as a Capital Budget Analyst. In these roles, I provided policy, data, and financial analysis to lead process improvement projects across city divisions to support vital city services. In September 2021, I joined Consumers Energy as a Senior Business Support Analyst in Electric Distribution Strategy and moved to the Cost Analysis and Pricing section as a Principal Rates Analyst in January 2024. In October 2024, I transferred to the Regulatory Policy and Research section.

**Q. What are your responsibilities as Principal Rates Analyst?**

A. In my current role with the Regulatory Policy and Research section, I provide analysis, strategic guidance, and technical support for regulatory filings, reports, and emergent issues. As a Principal Rates Analyst in the Cost Analysis and Pricing section, I was responsible for maintaining the electric and natural gas rate design models and sponsoring rate design financial studies, testimony, and exhibits in filings with the Michigan Public Service Commission ("MPSC" or the "Commission").

**Q. Have you previously filed testimony with the MPSC?**

A. Yes. I have filed testimony in the following case:

| | |
|---|---|
| Case No. U-21557 | Consumers Energy's 2023 Energy Waste Reduction ("EWR") Reconciliation. |

**Q. What is the purpose of your direct testimony in this proceeding?**

A. The purpose of my direct testimony is to present the Company's gas Cost-of-Service Study ("COSS") for the 12-month period ending October 31, 2026 ("test year").

**Q. Is the Company proposing any changes to the COSS methodologies previously approved by the Commission?**

A. Yes. Because the Company is proposing changes to the COSS methodologies approved by the Commission in prior cases, in accordance with the Commission's rate case filing requirements established in Case No. U-18238, the Company is sponsoring two versions of the COSS. The first COSS (Version 1) employs the methodologies previously adopted by the Commission in Case No. U-20650 updated for the financial information and supporting data sponsored by other witnesses in this case. The second COSS (Version 2) starts with the Version 1 COSS and incorporates three Company proposals that are responsive to issues or topics raised in Case No. U-21490. The Company is proposing to:

(1) remove Asset Retirement Costs ("ARC" or the Asset Retirement Obligation "ARO") from the calculation of other distribution plant; (2) break out and allocate other distribution plant by Federal Energy Regulatory Commission ("FERC") account; and (3) breakout and separately allocate Customer Care Center ("CCC") and the Business Customer Care ("BCC") expenses. The Company's proposal to breakout other distribution plant by FERC account complies with the settlement agreement in Case No. U-21490.

In addition to COSS Version 1 and COSS Version 2, the Company is presenting an additional COSS for informational purposes as agreed upon in the Company's settlement agreement in Case No. U-21490. This additional COSS replaces Average & Peak ("A&P") methods with Average & Excess ("A&E") as proposed by the Association of Businesses Advocating Tariff Equity ("ABATE") in Case No. U-21490. The Company is not advocating that the Commission adopt this method in its final COSS in this case but recommends adoption of COSS Version 2 for setting rates in this case.

**Q. Are you sponsoring any exhibits?**

A. Yes, I am sponsoring the following exhibits:

| | |
|---|---|
| Exhibit A-16 (SMG-1) Schedule F-1 | Gas Cost-of-Service Study – Version 1 - Projected 12 Month Period: November 2025 – October 2026; |
| Exhibit A-16 (SMG-2) Schedule F-1.1 | Gas Cost-of-Service Study – Version 2 - Projected 12 Month Period: November 2025 – October 2026; |
| Exhibit A-54 (SMG-3) | Gas Cost-of-Service Study – Average & Excess; |
| Exhibit A-55 (SMG-4) | Gas Cost-of-Service Study – Allocation of Home Products Credit; |

| | |
|---|---|
| Exhibit A-56 (SMG-5) | Gas Cost-of-Service Study – ABATE Witness Jonathan Ly's Direct Testimony Pages 11-12 (Average & Excess) Case U-21490; |
| Exhibit A-57 (SMG-6) | Detailed Analysis of FERC Account 378. |

**Q. Were these exhibits prepared by you or under your supervision?**

A. Exhibits A-16 (SMG-1), Schedule F-1; A-16 (SMG-2), Schedule F-1.1, A-54 (SMG-3), A-55 (SMG-4), and A-57 (SMG-6) were all prepared by me or under my direction and supervision. Exhibit A-56 (SMG-5) was taken from the transcript in Consumers Energy's last gas rate case, Case No. U-21490.

**Q. How is your direct testimony organized?**

A. My direct testimony is organized as follows:

I. COST OF SERVICE OVERVIEW

II. TEST YEAR COST OF SERVICE - VERSION 1

III. TEST YEAR COST OF SERVICE – VERSION 2

IV. IMPACT OF UTILIZING THE A&E METHOD

V. DETAILED ANALYSIS OF FERC ACCOUNT 378

VI. PRODUCTS CREDIT ALLOCATION

## I. COST OF SERVICE OVERVIEW

**Q. What is COSS?**

A. A COSS is a three-part analysis that quantifies the utility's cost to serve each rate class. It provides the utility and stakeholders with important information regarding each rate class's contribution to the total revenue requirement and the nature of those costs. Ultimately, the information provided by the COSS is used to guide rate design among other things. The

fundamental guiding principle used to assign costs in the COSS is cost causation. In other words, the costs assigned to a customer or group of customers should reflect how those customers drive or influence the utility's costs.

**Q. What are the three parts or steps involved in performing a COSS?**

A. The first step is functionalization, followed by classification, and finally allocation. Cost functionalization involves the identification and separation of plant and expenses into specific categories based on the activity or "function" that each cost is incurred to provide or support. Consumers Energy's functional cost categories are Transmission, Distribution, and Storage. Cost classification, the second step, involves the categorization of functionalized costs into demand, customer, and energy components according to the primary cost drivers. The final step is cost allocation. Allocation assigns costs to each customer class using a variety of factors that correlate to the identified cost drivers. Common allocation factors include the number of customers, throughput or usage, and peak consumption among others. This process is relatively standard across the utility industry and supported by the National Association of Regulatory Utility Commissioners ("NARUC") Gas Distribution Rate Design Manual.

## II. TEST YEAR COST OF SERVICE - VERSION 1

**Q. Please describe Exhibit A-16 (SMG-1), Schedule F-1.**

A. Exhibit A-16 (SMG-1), Schedule F-1, is a 16-page exhibit that summarizes the results of the Version 1 COSS. As explained earlier in my testimony, the Version 1 COSS employs the methodologies previously adopted by the Commission in Case No. U-20650 updated for the financial information and supporting data sponsored by other witnesses in this case. The Company also made routine updates for historical and test year data that are used to

derive COSS cost detail and the various functional, classification, and allocation factors. Page 1 of the exhibit summarizes the results of the COSS; total Company gas information for the test year is found in column (d) while columns (e) through (l) breakout the cost to serve for each rate class. Total rate base by rate is shown on line 33 with the return on rate base shown on line 37. Adjusted net operating income is shown on line 32 and is calculated by subtracting test year total expenses from revenue, adjusting for Allowance for Funds Used During Construction. The associated income and revenue deficiencies are shown on lines 41 and 42 respectively and are supported by Company witness Heather L. Rayl. The proposed base rate design revenue target for each rate class, which is shown on line 46, is found by removing Cost of Goods Sold and miscellaneous revenue from the total cost of service. Page 2 provides a breakout of the proposed base rate design revenue target by rate class for each functional cost category (transmission, storage, and distribution). Exhibit A-16 (SMG-1), Schedule F-1, pages 3 through 10, provide detail on rate base, operating and maintenance ("O&M"), and revenue that supports the summary information presented on Exhibit A-16 (SMG-1), Schedule F-1, pages 1 and 2. Exhibit A-16 (SMG-1), Schedule F-1, pages 11 through 16, support the functionalization, classification, and allocation factors utilized in the COSS.

## III. TEST YEAR COST OF SERVICE – VERSION 2

**Q. Please describe Exhibit A-16 (SMG-2), Schedule F-1.1 and explain how it differs from the Version 1 COSS (Exhibit A-16 (SMG-1), Schedule F-1).**

A. Exhibit A-16 (SMG-2), Schedule F-1.1 is a 16-page exhibit that starts with the Version 1 COSS (Exhibit A-16 (SMG-1), Schedule F-1) and incorporates the three Company proposals cited earlier in my testimony to: (1) remove asset retirement costs ("ARC") from

the calculation of other distribution plant; (2) break out and allocate other distribution plant by FERC account; and (3) breakout and separately allocate CCC and BCC expenses. The page and line references in the Version 1 COSS also apply to Version 2. A summary of the results of the Version 2 COSS results and how it compares to Version 1 for each rate class is shown in Table 1.

**Table 1: Summary of COSS Impact by Rate ($ in Millions)**

**Table 1: Summary of COSS Impacts by Rate ($ in Millions)**

| Description | Total | Residential | Rate GS-1 | Rate GS-2 | Rate GS-3 | Rate ST | Rate LT | Rate XLT | Rate XXLT |
|---|---|---|---|---|---|---|---|---|---|
| Present Revenue | $ 1,547 | $ 1,111 | $ 173 | $ 132 | $ 29 | $ 35 | $ 27 | $ 30 | $ 10 |
| Version 1 Update | $ 248 | $ 191 | $ 14 | $ 6 | $ 3 | $ 13 | $ 9 | $ 11 | $ 2 |
| **Version 1 COSS** | $ 1,795 | $ 1,302 | $ 187 | $ 137 | $ 32 | $ 48 | $ 36 | $ 41 | $ 12 |
| | 16.0% | 17.2% | 8.3% | 4.5% | 10.7% | 36.7% | 32.2% | 34.8% | 20.6% |
| +Remove ARC | $ - | $ 7.4 | $ (0.4) | $ (1.7) | $ (0.5) | $ (0.9) | $ (1.0) | $ (2.0) | $ (0.8) |
| +Other Dist. FERC | $ - | $ 2.1 | $ (0.0) | $ (0.3) | $ (0.1) | $ (0.2) | $ (0.3) | $ (0.8) | $ (0.3) |
| +BCC/CCC | $ - | $ 2.0 | $ 0.7 | $ (0.9) | $ (0.3) | $ (0.5) | $ (0.4) | $ (0.4) | $ (0.1) |
| **Version 2 COSS** | $ 1,795 | $ 1,313 | $ 187 | $ 134 | $ 31 | $ 46 | $ 34 | $ 38 | $ 11 |
| | 16.0% | 18.2% | 8.4% | 2.2% | 7.5% | 32.0% | 26.0% | 24.3% | 8.7% |

### A) Asset Retirement Costs

**Q. Please explain why the Company is proposing to remove ARC from other distribution plant.**

A. The Company is proposing to remove ARC from the COSS calculation of other distribution plant because these costs are not included in the distribution plant revenue requirement. The Company submitted this same proposal in Case Nos. U-21308 and U-21490 which was not contested by any party in that case and was adopted in the settlement COSS.

As shown in Table 2, removing ARC decreases the percentage of distribution plant categorized as "Distribution Plant – Other" from 8.61% to 5.81% and increases the share of plant in other categories.

**Table 2: Comparison of Distribution Plant Major Categories**

| Distribution Plant Major Categories | Version 1 | Version 2 |
|---|---|---|
| Distribution Plant – Other | 8.61% | 5.81% |
| Mains – High Pressure Capable | 4.17% | 4.30% |
| Mains – Non-High Pressure Capable | 27.36% | 28.20% |
| Services & Meters | 59.86% | 61.69% |

**B) <u>Breakout of Other Distribution Plant by FERC Account</u>**

**Q. Please explain how the COSS has treated other distribution plant in the past.**

A. Historically, the Company has allocated other distribution plant using Allocator 105. It includes volumes from customers attached to high-pressure mains and customers attached to non-high-pressure mains with an adjustment that removes volumes that bypass the high-pressure system. In Case Nos. U-21148 and U-21308, the Company proposed using Allocator 104 in place of Allocator 105 since Allocator 104 is based on total annual throughput and peak month throughput.

**Q. Please explain why the Company is proposing to break out other distribution plant in this case.**

A. In Case No. U-21308, ABATE witness Jonathon Ly argued it is not appropriate for other distribution plant be allocated in aggregate because the accounts included serve different functions. In rebuttal, the Company agreed to breakout other distribution plant costs on a more detailed FERC account basis in the next rate case which was formally reflected in the Case No. U-21308 settlement agreement. This same breakout was included in Case No. U-21490 and was formally reflected in the Case No. U-21490 settlement agreement.

**Q. What FERC accounts are included in other distribution plant?**

A. Other distribution plant includes costs in FERC Accounts 374, 375, 377, 378, and 382 where:

- **Account 374 Land & Land Rights** includes cost of land and land rights used in connection with distribution operations. The attainment of Land and Land Rights (Fee Land or Right of Way Easement) for roads or driveways, regulator stations, and tree rights is the foundation to lay down the Company's distribution system.

- **Account 375 Structures and Improvements** includes cost of structures and improvements used in connection with distribution operations. Structures and improvements to Gas Boiler Building, Gas Odorizing Station Building, Gas Regulator Building, etc. are critical to the safe and reliable operations of the Company's distribution system. They benefit all customers.

- **Account 377 Compressor station equipment** includes costs of installed compressor station equipment and associated appliances used in connection with distribution system operations. Air Compressors, Detectors, Sensors, Transformers, Transmitters, Valves, Uninterruptible Power Supplies, etc. are critical to the safe and reliable operations of the Company's distribution system. They benefit all customers.

- **Account 378 Measuring and regulating station equipment** generally includes costs of installed meters, gauges, and other equipment used in measuring and regulating gas in connection with distribution system operations other than the measurement of gas deliveries to customers. They are critical to the safe and reliable operations of the Company's distribution system. They benefit all customers.

- **Account 382 Meter installations** include cost of labor and materials used and expenses incurred in connection with the original installation of customer meters. Examples include installations of meters, rotary meters, meter regulator bypasses, Gas Sampler, etc.

**Q. How is the Company proposing to allocate other distribution plant for FERC Accounts 374, 375, 377 and 378?**

A. The Company proposes to allocate other distribution plant using Allocator 104 for FERC Account 374, 375, 377 and 378. Costs in these FERC accounts, as described above, are incurred to serve all customers. Since Allocator 104 is based on each rate class's respective forecasted total annual throughput and peak month throughput, the Company believes it is

an improvement over Allocator 105 which excludes volumes that bypass the high-pressure system.

**Q. How is the Company proposing to allocate other distribution plant for FERC Account 382?**

A. The Company proposes to allocate other distribution plant using Allocator 108 for FERC Account 382. Costs in this FERC account, as described above, are incurred in connection with the original installation of customer meters. Since Allocator 108 is weighted by the average residential customer hook up cost and is based on each rate class's respective forecasted average number of customers, the Company believes it is an improvement over Allocator 104 which is based on each rate class's respective forecasted total annual throughput and forecasted peak month throughput.

**C) <u>Customer Care Center and Business Customer Care Expense</u>**

**Q. How have CCC and BCC costs been allocated to customers in the past?**

A. Historically, CCC and BCC costs were included in the COSS line item "O&M Excluding A&G" which gets divided among several sub-categories using historic ratios and assigned a variety of allocators.

**Q. How is the Company proposing to allocate CCC and BCC costs in Version 2 of the COSS?**

A. The Company has broken out CCC and BCC costs as separate line items in the COSS and developed two new allocators: Allocator 114 which calculates the share of customers (by rate class) using the BCC, and Allocator 115 which calculates the share of customers (by rate class) using the CCC. The CCC serves residential and small business customers while the BCC serves commercial and industrial customers. Because business customers may

utilize the CCC or BCC, the Company obtained data on the number of customers by rate class served by the BCC as a reasonable measure of resource utilization and cost causation. This data was then used to calculate both Allocators 114 and 115. Support for these calculations can be found in WP-SMG-25.

## IV. IMPACT OF UTILIZING THE A&E METHOD

**Q. Please explain why the Company is presenting the A&E method in this case.**

A. In the Case No. U-21490 settlement agreement the Company agreed to provide a COSS that calculated the impact of utilizing the A&E method. The COSS results using the A&E method can be found in Exhibit A-54 (SMG-3).

**Q. Please explain how the A&E method is calculated.**

A. The A&E method is comprised of two components. The first component is based on average annual throughput weighted by a utility's system load factor. The second component considers the non-coincident peak ("NCP") which is derived using each class's maximum monthly throughput. To calculate the NCP method in this case, the Company relied on the A&E method developed in ABATE witness Ly's Direct Testimony and Workpapers in Case No. U-21490. Support for each class's NCP calculation can be found in WP-SMG-26. Mr. Ly's Direct Testimony from Case No. U-21490 (pages 11-12) can be found in Exhibit A-56 (SMG-5).

**Q. What is the impact of utilizing the A&E method on the COSS results?**

A. Table 3 shows how the results of the A&E COSS compared to the results of the Version 2 COSS:

**Table 3: A&E COSS Impacts by Rate Class ($ in Millions)**

**Table 3: Summary of A&E Method ($ in Millions)**

| Description | Total | Residential | Rate GS-1 | Rate GS-2 | Rate GS-3 | Rate ST | Rate LT | Rate XLT | Rate XXLT |
|---|---|---|---|---|---|---|---|---|---|
| Version 2 COSS | $ 1,795 | $ 1,313 | $ 187 | $ 134 | $ 31 | $ 46 | $ 34 | $ 38 | $ 11 |
| A&E COSS | $ 1,795 | $ 1,310 | $ 188 | $ 132 | $ 33 | $ 49 | $ 33 | $ 35 | $ 13 |
| Difference | $ - | $ (3) | $ 1 | $ (2) | $ 2 | $ 3 | $ (1) | $ (2) | $ 2 |
| | 0.0% | -0.2% | 0.4% | -1.5% | 6.5% | 5.8% | -2.5% | -5.9% | 21.6% |

**Q. Is the Company proposing to adopt the A&E method?**

A. No. While the Company believes the A&E method is reasonable and makes some improvements to the A&P method, the Commission has consistently ruled in favor of using the A&P method to allocate distribution mains costs, such as in Case No. U-10150, Case No. U-18124, and Case No. U-20322, to name a few.

## V. DETAILED ANALYSIS OF FERC ACCOUNT 378

**Q. Please explain why the Company is presenting a detailed analysis of FERC Account 378.**

A. In the Case No. U-21490 settlement agreement, the Company agreed to provide a study with a more detailed analysis of FERC Account 378. Specifically, the Company agreed to:

(1) Identify the costs in FERC Account 378 associated directly with measuring and regulator stations;

(2) Identify, with as much granularity as available, all other costs contained in FERC Account 378;

(3) Identify the total number of measuring and regulator stations in FERC Account 378 that regulate pressure from (a) high-pressure mains to high- pressure mains, (b) high-pressure mains to non-high-pressure mains, and (c) non-high-pressure mains to non-high-pressure mains; and

(4) Provide an analysis, either based on existing costs or an estimate of building new assets, that would allow for the allocation of measuring and regulator station costs between high pressure and non-high pressure.

**Q. Please explain how Exhibit A-57 (SMG-6) addresses the settlement agreement language from parts 1 through 3 from the settlement agreement in Case No. U-21490.**

A. Exhibit A-57 (SMG-6) contains the costs in FERC Account 378 associated directly with measuring and regulator stations on line 1, column e. The remaining costs contained in FERC Account 378 include the Huron Compressor station costs, the total of which are show in Exhibit A-57 (SMG-6) line 2, column e, and gas Odorization costs on line 3, column e. The Huron Compressor station serves to increase the pressure of the Company's high-pressure distribution system in Huron County to meet the demands of all customers during the highest demand days. Odorization serves as a safety measure for all customers and as such should be allocated to all customers.

The total number of measuring and regulator stations in FERC Account 378 that regulate pressure from high-pressure mains to high-pressure mains are shown on line 5, column c. The total number of measuring and regulator stations in FERC Account 378 that regulate pressure from high-pressure mains to non-high-pressure mains are shown on line 6, column c. The total number of measuring and regulator stations in FERC Account 378 that regulate pressure from non-high-pressure mains to non-high-pressure mains are shown on line 7, column c.

**Q. Please explain how Exhibit A-57 (SMG-6) addresses the settlement agreement language from part 4 from the settlement in Case No. U-21490.**

A. The data contained in Exhibit A-57 (SMG-6), lines 5 through 7 provides the necessary information to separate and functionalize the costs in FERC Account 378 that service high-pressure mains and those that serve non-high-pressure mains. This detail can be used

to determine an allocator to distribute the share of costs for high pressure and non-high pressure.

**Q. Why do the total book values in line 1, column e not match to the total book value in line 7 column e?**

A. The values in line 1, column e, reflect the Company's property accounting records for FERC Account 378 based on a typical life cycle of the measuring and regulator station assets. The values in line 8, column e, reflect the total book value of active measuring and regulator station assets recorded in the Company's GIS database. There is typically a delay between when an asset is modified and when the asset's book value is formally adjusted in the Company's property accounting records. The Company is continually reviewing its internal data to reconcile the values in lines 1 and 8. For these reasons, the data from lines 5 through 8 in Exhibit A-57 (SMG-6) provides the most representative data to develop an allocation of measuring and regulator station costs between high pressure and non-high pressure.

## VI. PRODUCT CREDIT ALLOCATION

**Q. How does the Company propose allocating the projected revenue generated by the Home Products Credit?**

A. The Company proposes using Allocator 209 (Total O&M excluding Admin & General) as demonstrated in Exhibit A-55 (SMG-4). The Company invests O&M into the Home Products program and Allocator 209 is the total O&M allocator that includes working capital and excludes Admin & General. The Company believes it is reasonable to credit, proportionally, those who have paid for the program in the allocation of the Home Products Credit.

**Q. Does this complete your direct testimony?**

A. Yes.

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

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|---|---|---|
| In the matter of the application of<br>**CONSUMERS ENERGY COMPANY**<br>for authority to increase its rates for the<br>distribution of natural gas and for other relief. | )<br>)<br>)<br>)<br>) | Case No. U-21806 |

**REBUTTAL TESTIMONY**

**OF**

**SAMUEL M. GELLER**

**ON BEHALF OF**

**CONSUMERS ENERGY COMPANY**

May 2025

**Q. Please state your name and business address.**

A. My name is Samuel M. Geller, and my business address is One Energy Plaza, Jackson, Michigan, 49201.

**Q. Are you the same Samuel M. Geller who previously presented direct testimony in this case?**

A. Yes.

**Q. What is the purpose of your rebuttal testimony?**

A. The purpose of my rebuttal testimony is to respond to Cost-of-Service Study ("COSS") issues raised in the direct testimonies of Michigan Public Service Commission ("MPSC" or the "Commission") Staff ("Staff") witnesses Kevin S. Krause and Nicholas M. Revere; Lansing Board of Water and Light and Michigan State University ("LBWL-MSU") witness Timothy S. Lyons, and Citizens Utility Board of Michigan ("CUB") witness Richard J. Bunch.

**Q. Have you prepared any exhibits in conjunction with your rebuttal testimony?**

A. No.

**Q. How is your rebuttal testimony organized?**

A. My rebuttal testimony is organized as follows:

**I. REBUTTAL OF STAFF WITNESS KRAUSE AND CUB WITNESS BUNCH**

**II. REBUTTAL OF STAFF WITNESS REVERE**

**III. REBUTTAL OF LBWL-MSU WITNESS LYONS**

## I. REBUTTAL OF STAFF WITNESS KRAUSE AND CUB WITNESS BUNCH

**Q. Please describe Staff witness Krause's proposed allocator change.**

A. Beginning on page 5 of his direct testimony, Staff witness Krause proposes changing the allocator for uncollectible expenses based on revenue. Staff witness Krause reasons that the three-year average of historical write-offs is inappropriate as it does not reflect the reality of the way uncollectible costs are incurred or how they should be borne by the classes. Staff witness Krause argues that uncollectible expenses should be shared by all customers consistent with how their overall costs are recovered by the Company.

**Q. Do any other witnesses propose a similar allocator change?**

A. Yes. On page 25 of his direct testimony, CUB witness Bunch recommends that the Commission order the Company to allocate uncollectible expenses to each class according to Cost of Service plus Cost of Gas. On page 26 of his direct testimony, Mr. Bunch clarifies that his recommendation is to also allocate uncollectible expenses according to revenue. CUB witness Bunch argues that the current method for allocating uncollectible expenses is inconsistent with past commission orders.

**Q. Does the Company agree with Staff witness Krause's proposed allocator change?**

A. Yes. The Company will agree to Staff's proposal to use Present Total Revenue (Allocator 111) for uncollectible expenses and discontinue using a three-year average of historical write-offs, as previously approved by the MPSC in its Case No. U-20322 Order. This allocation method follows Staff witness Krause's proposal to allocate uncollectible expenses consistent with the way the Company allocates these expenses in the electric COSS.

**Q. Please describe Staff witness Krause's proposal to modify the Company's calculation of customer charges.**

A. On page 7 of his direct testimony, Staff witness Krause proposes to calculate customer charges based solely on historical amounts in the instant case. This is a departure from the method approved in the Company's previous gas rate case in which the customer charge was calculated based on a combination of historical and projected expenses. Staff witness Krause argues that utilizing only historical costs ensures that the customer charge calculation will avoid including inappropriate costs in the customer charge.

**Q. Does the Company agree with Staff witness Krause's calculation of the customer charge?**

A. No. The breakout of test year costs in the COSS based on historic ratios is reasonable and appropriate. Since rates are designed based on a forward-looking test year, customer costs (and the customer charge) should reflect test year costs. Accordingly, the Company applied the same methods and used the same inputs previously approved by the Commission to calculate the customer costs and resulting customer charge in this case.

## II. REBUTTAL OF STAFF WITNESS REVERE

**Q. Please describe Staff witness Revere's proposed allocator change.**

A. On page 7 of his direct testimony, Staff witness Revere proposes allocating FERC account 378 costs based on a composite allocator (shown in Exhibit S-21.0) that seeks to more accurately assigns costs to serve customers based on pressure level. As required in the settlement agreement in Case No. U-21406, the Company submitted a more detailed analysis of the costs in FERC Account 378 in this case which identified the costs associated with measuring and regulating stations serving different pressure levels. The composite

allocator crafted by Staff witness Revere utilizes this information to sort FERC Account 378 costs and assign them based on pressure level.

**Q. Does the Company agree with Staff witness Revere's proposed allocator change?**

A. Yes. The Company agrees to use Staff witness Revere's composite allocator for FERC account 378 costs. Staff witness Revere's composite allocator better reflects the cost-causative relationship than the Company's current method which allocates costs based on annual and peak usage for all customers at all pressure levels.

## III. REBUTTAL OF LBWL-MSU WITNESS LYONS

**Q. Please describe LBWL-MSU witness Lyons' proposed allocator change.**

A. On pages 12 through 15 of his direct testimony, Mr. Lyons proposes allocating FERC accounts 374, 375, 377, and 378 with Allocator 217 which functionalizes other distribution plant costs into High Pressure ("HP") and non-HP mains before allocating costs to each rate class. LBWL-MSU witness Lyons argues that this approach is widely accepted in the utility industry and ensures that HP customers are not allocated costs for assets that do not serve them.

**Q. Does the Company agree with LBWL-MSU witness Lyons' recommendation for FERC account 378?**

A. No. As described above, Staff witness Revere's proposal represents a more accurate methodology for allocating other plant distribution expenses. Staff witness Revere's composite allocator uses Company-provided data for FERC account 378 to first evaluate which cost categories should be broken out by pressure class and which should not. As described in Staff witness Revere's testimony on page 7, "Allocator 104 is appropriately applied to the two 'All Other Costs' categories (Huron Compressor Station and

Odorization) which represent approximately 14% of the total, as no evidence has been provided showing those costs are associated with any given pressure level directly." This first step ensures that the over $41 million in these cost categories continue to be allocated to all customer classes based on average and peak use. LBWL-MSU witness Lyons' proposal does not critically examine which cost categories within FERC account 378 serve all pressure classes which allow the XXLT customers to avoid costs that are appropriately allocated to them.

**Q. Does the Company agree with LBWL-MSU witness Lyons' recommendation to apply Allocator 217 to the remaining Other - Distribution Plant expenses in FERC accounts 374, 375, and 377?**

A. No. The Company also disagrees with LBWL-MSU witness Lyons' approach to functionalizing FERC accounts 374, 375, and 377 based on pressure. Without additional analysis of the composition of the remaining $149 million in Other Distribution Plant, the Company believes it is unreasonable to change the allocation method for FERC accounts 374, 375, and 377 solely based on pressure. As described above, closer study of FERC account 378 revealed that allocating the entirety of Other Distribution Plant expenses based on pressure is inappropriate since it contains costs that are not associated with any particular pressure class. As an example, one of these cost categories cited by Staff witness Revere is the Huron Compressor Station which maintains the pressure and the flow of natural gas to the high-pressure distribution system. All customers, at all pressure levels, are served by high pressure distribution either directly or downstream of the high-pressure system. According to Figure 2 in LBWL-MSU witness Lyons' testimony, FERC account 377 contains $11 million worth of assets serving the very same Huron Compressor station.

If it is not appropriate to allocate Huron Compressor Station Costs within FERC account 378 based solely on pressure, then it stands to reason that allocating an entire account of Huron Compressor Station costs based on pressure is similarly inappropriate.

## IV. SUMMARY

**Q. Please summarize your response to the direct testimony of Staff, LBWL-MSU, and CUB.**

A. 1. The Company agrees with Staff witness Krause's and CUB witness Bunch's proposals to change the allocation of uncollectible expense based on revenue. The Company supports using Present Total Revenue (Allocator 111) for uncollectible expenses in this case. This allocation is consistent with the Company's allocation for uncollectible expenses in the Electric COSS.

2. The Company agrees with Staff witness Revere's proposal to change the allocation of FERC account 378 expenses based on a composite allocator detailed in Exhibit S-21.

3. The Company recommends rejecting LBWL-MSU witness Lyons' proposal to allocate other distribution plant costs in FERC accounts 374, 375, 377, and 378 based on pressure class by using Allocator 217.

**Q. Does this conclude your rebuttal testimony?**

A. Yes.

MR. RUSZKIEWICZ: The next witness for the Company is Michael P. Griffin. Based on stipulation of the parties, the Company moves to bind in the testimony of Mr. Griffin. Mr. Griffin had direct revised testimony which consisted of a cover page and 50 pages of prefiled testimony. He also had rebuttal testimony, a cover page plus 28 pages of prefiled testimony.

The Company also moves to admit Mr. Griffin's exhibits, which consist of Exhibit A-58, A-12 revised, A-59, A-60, A-61 revised, A-62, A-63, A-135, A-136, A-137.

JUDGE VARCHETTI: Are there any objections to the admission of Mr. Griffin's revised direct or rebuttal testimony, or any of his associated exhibits?

Hearing none, then, the testimony is bound into the record, and the exhibits are admitted.

MR. RUSZKIEWICZ: Thank you, Your Honor.

(Revised Direct and Rebuttal Testimony bound in)

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

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| In the matter of the application of<br>**CONSUMERS ENERGY COMPANY**<br>for authority to increase its rates for the<br>distribution of natural gas and for other relief. | )<br>)<br>)<br>)<br>) | Case No. U-21806 |

# REVISED DIRECT TESTIMONY

# OF

# MICHAEL P. GRIFFIN

# ON BEHALF OF

# CONSUMERS ENERGY COMPANY

December 2024

**Q. Please state your name and business address.**

A. My name is Michael P. Griffin, and my business address is 4600 Coolidge Highway, Royal Oak, MI 48073.

**Q. By whom are you employed?**

A. I am employed by Consumers Energy Company ("Consumers Energy" or the "Company").

**Q. What is your position with Consumers Energy?**

A. I presently hold the position of Senior Strategy Manager in the Gas Strategy Department, a position I have held since July 2021.

**Q. What are your responsibilities as Senior Strategy Manager?**

A. I am responsible for the cross-functional research, analysis, and oversight of natural gas transmission and certain distribution assets and transmission portfolio management strategy. This includes the development, recommendation, and administration of the Natural Gas Delivery Plan ("NGDP").

**Q. Please describe your educational background?**

A. I earned a Bachelor of Arts in Marketing from Michigan State University in 1985, and earned a Master of Business Administration from Wayne State University in 1998.

**Q. Please describe your work experience?**

A. I began working for the Company in 1987. Since that time, I have held positions of increasing responsibility including Marketing Consultant, Customer Energy Specialist, Senior Business Support Consultant in the financial area, Gas Budgeting Director, and Director of Rate Cases and Controls, a position I held beginning in 2008. As Director of Rate Cases and Controls, I was instrumental in the development of testimony and exhibits, and in supporting various witnesses in multiple gas and electric rate cases for the Gas and

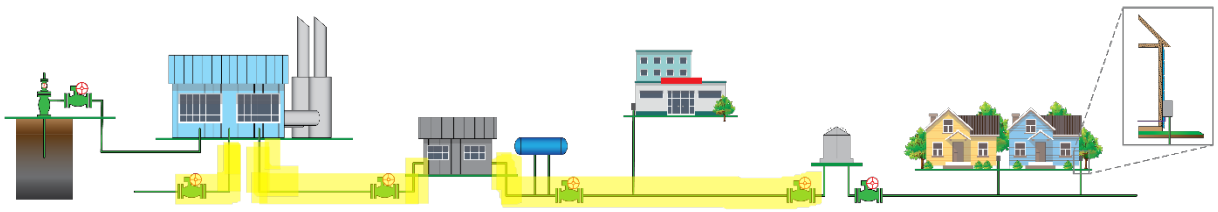
Electric Engineering, Operations, and Customer Operations departments. Since July 2021, I have held the role of Senior Strategy Manager for the Company's transmission assets.

**Q. Have you previously testified before the Michigan Public Service Commission ("MPSC" or the "Commission")?**

A. Yes, I have recently provided testimony in MPSC Case No. U-21148, MPSC Case No. U21308 and MPSC Case No. U-21490.

**Q. What is the purpose of your direct testimony?**

A. My direct testimony explains the Company's request for rate relief as it relates to its Gas Transmission and certain Distribution capital expenditures and Operating and Maintenance ("O&M") expenses for the programs identified below. These expenditures are primarily related to operations of the Company's high-pressure distribution and transmission systems. Specifically, these investments relate to the portion of the Company system that receives the high-pressure gas at the outlet of the Compressor Stations, and delivers the gas to the city gates, and from the city gates to the regulator stations. In the diagram below, these investments are inside the yellow highlighted section. These investments will help the Company meet its objectives of supplying safe, reliable, affordable, and clean energy to customers as described in the NGDP, Exhibit A-42 (NPD-1), sponsored by Company witness Neal P. Dreisig.



My direct testimony is divided into three sections: (i) Asset Relocation Transmission capital expenditures; (ii) Regulatory Compliance O&M and capital costs; and (iii) Capacity/Deliverability capital expenditures.

**Q. Are you sponsoring any exhibits with your direct testimony?**

A. Yes. I am sponsoring the following exhibits:

| | | |
|---|---|---|
| Exhibit A-58 (MPG -1) | | Summary of Actual & Projected Regulatory Compliance O&M Expenses; |
| Exhibit A-12 (MPG-2) | Schedule B-5.5 | Summary of Actual and Projected Capital Expenditures Transmission & Distribution Plant - Summary of Actual & Projected Gas Capital Expenditures; |
| Exhibit A-59 (MPG-3) | | Actual & Projected Gas Transmission Capital Expenditures - Asset Relocation Transmission Program; |
| Exhibit A-60 (MPG-4) | | Actual & Projected Gas Transmission Capital Expenditures – Regulatory Compliance Program; |
| Exhibit A-61 (MPG-5) | | Actual & Projected Gas Transmission and Distribution Capital Expenditures - Capacity/Deliverability Program; |
| Exhibit A-62 (MPG-6) | | Actual & Projected Gas Capital Expenditures - Transmission & Distribution Plant - TED-I Program Detail; and |
| Exhibit A-63 (MPG-7) | | Projected Capital Expenditures - Transmission & Distribution Plant, Summary of Actual & Projected Gas Capital Expenditures. |

**Q. Were these exhibits prepared by you or under your direction or supervision?**

A. Yes.

**Q. Please describe Exhibit A-58 (MPG-1).**

A. Exhibit A-58 (MPG-1) shows the total O&M expenses for the Regulatory Compliance Program that I am sponsoring. In my testimony, I will describe the program expenses and projects contained within this program. As shown on line 5 of Exhibit A-58 (MPG-1), the total O&M expenses I am sponsoring were $20,034,000 in 2023 and are projected to be $26,737,000 in 2024, $28,512,000 in 2025, and $23,129,000 for the 12 months ending October 31, 2026.

**Q. Please describe Exhibit A-12 (MPG-2), Schedule B-5.5.**

A. Exhibit A-12 (MPG-2), Schedule B-5.5, shows the total capital expenditures I am sponsoring. In my testimony I will describe each of the programs, any sub-programs, and corresponding expenditures for these items. As shown on line 4 of Exhibit A-12 (MPG-2), Schedule B-5.5, the capital expenditures for the programs I am sponsoring were $350,582,000 in 2023, and are projected to be $313,829,000 in 2024, $176,781,000 for the 10 months ending October 31, 2025, and $219,855,000 for the 12 months ending October 31, 2026.

**Q. Does the NGDP discuss the Company's gas transmission assets?**

A. Yes, it does.

**Q. Please describe the Company's 10-year investment plan for its gas transmission and distribution assets that you are sponsoring.**

A. Over the next 10 years, the Company will focus its transmission efforts to continue improving on inspections, reducing risk, and increasing its remediation pace for critical assets. To reach these objectives, the Company has completed the planned Transmission Enhancements for Deliverability & Integrity ("TED-I") pipeline projects and will be moving forward with smaller-scale infrastructure projects like valve replacements and

upgrades, along with line lowerings and the re-build schedule for city gate facilities. This information can be found in Exhibit A-42 (NPD-1), Section IV.C Transmission Asset Plan of the NGDP. The Company is also rebuilding distribution regulator station facilities. This information can be found in Exhibit A-42 (NPD-1), Section IV.D of the NGDP.

## I. ASSET RELOCATION TRANSMISSION PROGRAM

**Q. Please describe the capital expenditures related to the Asset Relocation Transmission Program as shown on Exhibit A-12 (MPG-2), Schedule B-5.5, line 1.**

A. The Asset Relocation Transmission Program includes gas transmission infrastructure replacement projects that are required due to civic improvement activities, initiated by federal, state, or local governmental units. This program also includes projects where transmission pipeline location or depth of cover requires relocation of an existing pipeline to prevent third-party damage, eliminate physical conflicts with other utilities, and ensure continued safe operation. Civic improvement projects replace or improve aging public infrastructure such as roadways, bridges, sewer lines, water lines, and drainage ditches. The Transmission Pipeline Engineering Department reviews all civic improvement projects to determine if conflicts require pipeline relocation. The Asset Relocation Transmission Program also includes relocation and lowering of natural gas transmission infrastructure to remediate reduction in cover due to grading and/or erosion.

For actual and potential asset relocation projects reviewed as a result of civic improvement projects, to minimize scope and expense, the Company works with the governmental units involved to coordinate work and to negotiate design criteria wherever possible. For instance, the Company reviews municipal project plans and tries to negotiate design changes to eliminate potential direct conflicts with Company facilities, such as gas

transmission lines, valve sites, or city gate stations. These negotiations reduce overall project scope and thus reduce the costs to both the taxpayer and the customer.

In addition, to further reduce costs, the Company coordinates project timelines with municipalities to align construction and restoration schedules. An example of the Company's ongoing coordination with municipalities in which civic improvement projects required pipeline relocation was in Oakland County when lowering segments of Line 1600 along Taft Road ahead of scheduled municipal road improvements planned by the City of Novi. This effort was undertaken to minimize disturbance and impact to the community. Furthermore, additional coordination in Saginaw County allowed the Company to lower a segment of Line 300 within the Parker Swamp Drain to safely facilitate scheduled drain maintenance activities.

Projects are also scoped as a result of instances where location or lack of depth of cover requires the relocation of an existing transmission pipeline to ensure continued safe operation and for damage prevention purposes. Projects are evaluated to determine if the reestablishment of cover can be a long-term, viable remediation option. Most projects are not selected for this type of remediation method given the likelihood of continued cover degradation over a period of time. The Asset Relocation Transmission Program projects are designed and constructed to comply with minimum soil cover requirements specified by State and Federal regulations, see, e.g., 49 CFR 192.317, 49 CFR 192.327(a), Michigan Gas Safety Standards, and Company requirements. These project types are described in more detail later in my direct testimony.

As shown on Exhibit A-12 (MPG-2), Schedule B-5.5, line 1, the capital expenditures for this program were $6,168,000 in 2023, and are projected to be

$17,389,000 in 2024, $19,138,000 for the 10 months ending October 31, 2025, and $24,726,000 for the 12 months ending October 31, 2026.

**Q. Please describe the development of the Company's Asset Relocation Transmission Program capital expenditure projections.**

A. These projections are based upon knowledge of specific projects planned for the next several years and prioritized accordingly by established risk and/or external third-party/civic schedule commitments. Examples of asset relocation projects included in these projected expenditures include:

- Line 300 Parker Swamp Drain Lowering civic improvement in Saginaw County;
- Line 1300 114th Ave line lowering in Allegan County;
- Line 100B Sleepy Hollow State Park ("SHSP") re-route in Clinton County;
- Lines 100A/B/C Chippewa River line lowerings in Isabella County;
- Line 1100 Rabbit River line lowering in Allegan County;
- Line 1200A line lowerings at Wetlands BR014 and BR017 in Branch County;
- Line 1200A Townline Road line lowering in Branch County; and
- Line 1200A Needham Road line lowering in Branch County.

The Company's projected expenditures are required to complete the level of asset relocations for known transmission line lowerings and civic improvement projects. Exhibit A-59 (MPG-3) provides further details on the expenditures included in this program.

**Q. Please describe the Line 100B SHSP re-route project.**

A. The Company filed for a certificate of public convenience and necessity pursuant to 1929 Public Act 9 ("Act 9") in MPSC Case No. U-21179 on December 15, 2021, for this project. The Act 9 was approved on March 3, 2022. The project was completed in 2024. As described in the Company's Application, page 2, in that case:

> In Case No. U-20618, Consumers Energy received Commission approval pursuant to Act 9 to construct and operate the Mid-Michigan Pipeline to replace the existing Line 100A pipeline between Chelsea and Ovid, Michigan… The Mid-Michigan Pipeline includes a reroute of Line 100A in SHSP away from the campground and beach area to allow for construction during the busy use of the park and removal of the pipeline from heavily used areas… Line 100B is a 26-inch natural gas pipeline that runs parallel to Line 100A through SHSP. Consumers Energy proposes to reroute Line 100B at the same time, and along the same route, as Line 100A. Just as with Line 100A, rerouting Line 100B will remove the pipeline from the heavily used beach and campground areas, and as a result will remove the addition of a valve site due to the reroute being located in a Class 2 area. Removal of the valve site will save approximately $1 million. The reroute away from the beach and campground areas will also result in less impact to park users in the event of future pipeline maintenance or remediation. The reroute of Line 100B will allow Line 100B to continue to parallel Line 100A, which will provide for more efficient and cost-effective maintenance of the pipelines in a single pipeline corridor. Line 100B is currently buried deeper than normal in the park, and rerouting Line 100B will allow the pipeline to be brought to normal depth allowing for improved operations and maintenance.

**Q. Please explain the methodology for selecting the Company-initiated projects in the Asset Relocation Transmission Program.**

A. Company-initiated projects executed under the Asset Relocation Transmission Program are selected based on a variety of considerations, including physical depth of cover, customer notifications, and Consumers Energy transmission pipeline risk model results, as determined by the Gas Asset Management System Integrity group. Risk modeling for the Asset Relocation Transmission Program involves determining the anticipated overall risk reduction that would result from reducing the relative risk score for third-party damage (by a percentage commensurate with increased depth of cover) and holding all other individual threat risk scores constant. Segments showing a higher overall risk reduction as a result of

increased depth of cover are graded as higher priority within the Asset Relocation Program. Prioritization may also be adjusted based on availability of transmission pipeline outages, continued coordination with local municipalities or governing authorities for civic-related work, and anticipated future replacement under another program (such as TED-I).

**Q. Please describe the customer benefits attained from the projects in this program.**

A. For Company-initiated Asset Relocation Transmission Projects, replacing and lowering pipeline segments in locations where grading or erosion has reduced cover to less than the depths specified by 49 CFR 192.327(a) and Company standard requirements provides benefits to customers by reducing the potential for third-party damage from activities such as plowing and drain maintenance. For example, industry data for risk management indicates that increasing the depth of cover from 3.0 feet to 4.5 feet reduces the threat of third-party damage occurrence by up to 56% (Muhlbauer, Pipeline Risk Management Manual). These projects also mitigate the risks of additional reduction in cover and future exposure of pipelines, which may in turn result in increased risk of vehicle damage, external loading, coating damage, pipe scouring, washouts, sinking, and corrosion at the soil-to-air interface. For Asset Relocation Transmission Projects initiated by civic improvement projects, customer benefits include reduced risk of third-party damage, maintenance of underground clearances specified by 49 CFR 192.325, and facilitation of the civic improvement projects. Customers also benefit when the Company coordinates with civic improvement projects as street and road disruptions are minimized.

## II. REGULATORY COMPLIANCE PROGRAM

**Q. Please describe the capital expenditures related to the Regulatory Compliance Program as shown on Exhibit A-12 (MPG-2), Schedule B-5.5, line 2.**

A. As shown on Exhibit A-12 (MPG-2), Schedule B-5.5, line 2, the capital expenditures for this program were $36,139,000 in 2023, and are projected to be $26,078,000 in 2024, $24,285,000 for the 10 months ending October 31, 2025, and $24,807,000 for the 12 months ending October 31, 2026.

I am sponsoring the following four programs in the Regulatory Compliance capital program:

- Pipeline Integrity Transmission Program;
- Pipeline Integrity Transmission Operated by Distribution ("TOD") Program;
- Cathodic Compression, Storage and Pipeline Program; and
- Maximum Allowable Operating Pressure ("MAOP") Compliance Pipeline Program.

**Q. Please describe the O&M expenses related to the Regulatory Compliance Program as shown on Exhibit A-58 (MPG-1).**

A. As shown on line 5 of Exhibit A-58 (MPG-1), the O&M expenses for this program were $20,034,000 in 2023 and are projected to be $26,737,000 in 2024, $28,512,000 in 2025, and $23,129,000 for the 12 months ending October 31, 2026.

I am sponsoring the following four programs in the Regulatory Compliance O&M program:

- Pipeline Integrity Transmission O&M Program;
- Pipeline Integrity TOD O&M Program;
- Corrosion Control Transmission O&M Program; and

- MAOP Transmission O&M Program.

As these O&M expenses are primarily tied to the capital expenditures in the capital programs described above, they will be consolidated below to describe the overall program spending.

## A. PIPELINE INTEGRITY TRANSMISSION PROGRAM AND PIPELINE INTEGRITY – TOD PROGRAM

**Q. Please describe the Pipeline Integrity Program.**

A. The Pipeline Integrity Program represents the necessary inspections and remediation O&M expenses and capital expenditures that allow the Company to remain compliant with regulations mandated by the federal Pipeline & Hazardous Materials Safety Administration ("PHMSA") and the Commission. The program costs are a function of the overall number of assessments, inspection tool types, baseline assessments, or reassessments to be completed in accordance with the Company's Pipeline Integrity Program.

**Q. Please describe PHMSA's requirements for a Pipeline Integrity Program.**

A. Federal Regulation, 49 CFR Part 192, Subpart O, specifies how pipeline operators must identify, prioritize, assess, evaluate, repair, and validate the integrity of natural gas transmission pipelines that could, in the event of a leak or failure, affect High Consequence Areas ("HCA"). These are areas where pipeline releases could have greater consequences to health, safety, or the environment. As a transmission pipeline operator, Consumers Energy must comply with these minimum federal safety standards. Under 49 CFR 192.907, by December 17, 2004, all pipeline operators, including Consumers Energy, were required to develop and follow a written Transmission Integrity Management Program ("TIMP") that addresses the risks on each covered transmission pipeline segment. In addition, Consumers Energy has updated its standards, procedures, and processes to adhere

to the additional requirements in Safety of Gas Transmission Pipelines, including Repair Criteria, Integrity Management Improvements, Cathodic Protection, Management of Change, and Other Related Amendments ("RIN2") by May 24, 2023, and other dates as outlined in the final rule.

**Q. Please describe the MPSC's requirements for a Pipeline Integrity Program.**

A. The MPSC has adopted and is the enforcement agency for the federal regulations. Additionally, the MPSC has published the Michigan Gas Safety Standards. These standards are additional rules the Company is required to follow.

**Q. What is the importance of a Pipeline Integrity Program?**

A. As stated above, a Pipeline Integrity Program is in place to validate and ensure the integrity of pipelines in HCA and outside of HCA, including inline inspectable Moderate Consequence Areas ("MCA") and segments within a Class III or Class IV location operating above 30% specified minimum yield strength ("SMYS"). This program provides a critical avenue that increases public safety through the identification and remediation of potentially hazardous conditions on the pipelines. Additionally, the program is important to ensure the reliability of the Company's transmission system remains intact by taking measures to prevent an unexpected failure on the system.

**Q. How was the Company's Pipeline Integrity Program developed?**

A. Consumers Energy's TIMP contains information related to how the Company identifies, prioritizes, assesses, evaluates, repairs, and validates the integrity of its gas transmission pipelines that could, in the event of a leak or failure, affect HCA. The TIMP is updated based upon regulations that have become effective since the inceptions of the program. To

minimize environmental and safety risks, Consumers Energy's TIMP delivers the following:

- Identifies HCA, required assessments Outside of HCA, and threats to covered pipeline segments:
  - Assessments Outside of HCA
    - Inline Inspectable MCA; and
    - Segments located within a Class III or IV location operating above 30% SMYS;
- Establishes a baseline assessment plan, including criteria for establishing reassessment intervals, a direct assessment plan, and a communication plan;
- Remediates conditions found during assessments;
- Specifies continual evaluation and assessment of the overall TIMP;
- Establishes a plan for confirmatory direct assessment;
- Requires additional preventative and mitigative measures, recordkeeping, and management of change; and
- Establishes a Quality Assurance process.

Pursuant to the federal regulations, this written document has been modified over the years for various reasons. Some of the reasons for modification include changes in inspection technology, changes or clarifications received from PHMSA, feedback from the MPSC Staff ("Staff"), and Company-driven changes.

**Q. Is the TIMP Manual provided to Staff?**

A. Yes. Staff has access to the Company's TIMP Manual, and when revisions to the TIMP Manual are made, a copy is sent to Staff.

**Q. As part of Transmission Integrity Management, do companies need to continuously improve their program?**

A. Yes, 49 CFR 192.907 and 49 CFR 192.911 require that an operator must make continual improvements to the program.

**Q. Does the Company's NGDP, Exhibit A-42 (NPD-1), discuss Consumers Energy's 10-year plan related to the Pipeline Integrity Program?**

A. Yes. Over the 10-year period of the NGDP, the Company is focusing on improving inspections, de-risking, and increasing its remediation pace for critical assets. The Company is continuing its current practice of striving toward six-year inspection and remediation cycles. The Company is updating its risk ranking methodology and transitioning its current relative risk model into a probabilistic risk model to ensure investments are concentrated on the right assets. As discussed in the NGDP, the Company will undertake the following:

- Complete baseline inspections for approximately 25 miles of the Company's mainline transmission system pipeline by year-end 2025 and maintain that plan based on a reassessment plan;
- Assess and develop a plan to proactively remediate high-risk pipe segments that are prone to higher risk threats like Stress Corrosion Cracking ("SCC") and corrosion; and
- Evaluate transmission-classified segments embedded in the distribution system—referred to as TOD—to determine if a baseline assessment or replacement is needed on a prioritized basis.

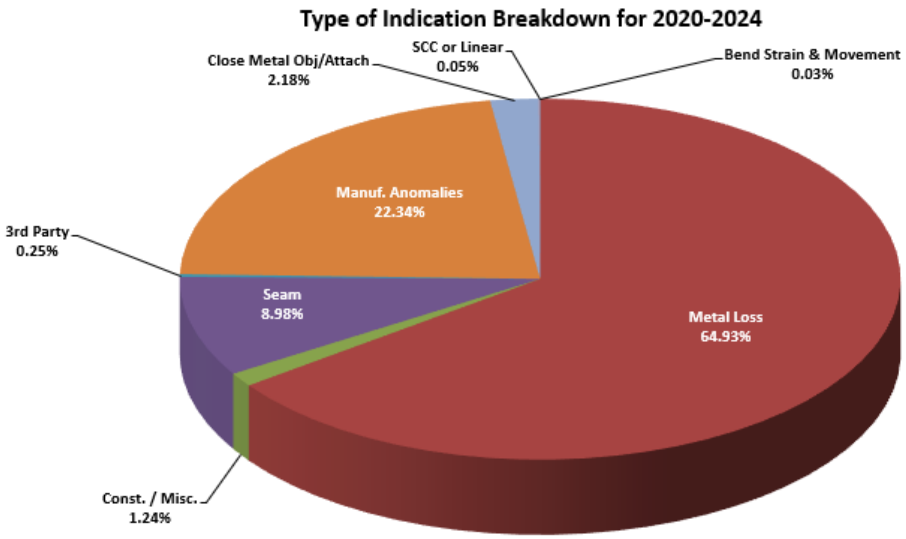
Exhibit A-42 (NPD-1), Section IV.C.2, provides additional information on these objectives.

**Q. What types of anomalies and threats has the Company experienced on its gas transmission system?**

A. Consumers Energy's TIMP has proven to find anomalies the Company is able to remediate, providing safe and reliable operations for customers. The Company has experienced several different types of anomalies on its gas transmission system, and continues to find new pipeline safety threats that require mitigation, as detailed later in my direct testimony. A breakdown of the type of anomalies found through traditional in-line inspection ("ILI") tool runs from 1999 to 2024 is shown in the Figure 1 below:

**Figure 1**

Type of Anomalies Found Through ILI Tool Runs 2020 through 2024




The anomaly indications are as follows:

1. Metal Loss encompasses all external and internal corrosion in the body of the pipe that has been predicted by the ILI tools;

2. Manufacturing anomalies include metal loss due to the manufacturing of the pipe and other manufacturing anomalies predicted in the body of the pipe;

3. Seam anomalies covers all external and internal corrosion in the seam weld, crack indications in the seam, and metal loss in the seam weld due to manufacturing processes;

4. Construction and Miscellaneous category include reinforced girth welds, sleeves, and other items that appear on or near the pipeline;

5. Metal Object and Attachment category includes extra metal and close metal objects to the pipelines;

6. Third-Party Damage includes any dents, deformations, and gouges on the pipelines;

7. SCC or Linear includes crack indications found in the body of the pipe and not on a seam; and

8. Locations on the system that have indication of Bend Strain or pipeline movement due to geohazards or construction activities.

As illustrated in the chart, the largest percentages of anomalies are metal loss or corrosion. From an industry perspective, corrosion is the number one threat to a transmission pipeline system. In keeping with regulatory and industry requirements, the Company promptly addresses this threat through a strong TIMP, and a robust corrosion control process that reduces the corrosion rate on pipelines.

The Company's TIMP program also addresses the threat of SCC. Many factors can affect the initiation and propagation of SCC, but a primary barrier to SCC is a pipeline's coating system. A secondary barrier is a cathodic protection system. When the coating on a pipe is compromised, the environmental factors that support SCC can develop under the right conditions. Since 2015, the Company has been assessing its pipelines that have the highest potential for SCC to occur, and there have been instances where SCC was found and remediated.

The Company also continues to conduct bending strain analyses and pipe movement studies on sections of its natural gas transmission system to identify potential

areas of high strain on its transmission pipelines. Since 2017, the Company has performed 62 bending strain analyses and performed remediation based on those results to improve the safety and reliability of the system.

**Q. Is a probabilistic risk model recommended by federal or state regulators?**

A. Yes, both. PHMSA has identified the probabilistic risk model as a potential best practice for pipeline operators over other risk models, as discussed in the technical information document, Pipeline Risk Modeling: Overview of Methods and Tools for Improved Implementation, published February 1, 2020, by PHMSA. Additionally, the MPSC recommended the transition in its September 11, 2019 Michigan Statewide Energy Assessment Final Report ("SEA").

**Q. What are the additional benefits of a probabilistic risk model for the safety and reliability to customers?**

A. When transmission risk modeling was first required by PHMSA, the industry explored the best options available to comply with regulations. The best option available at that time was a relative risk model, which uses a scoring system to weight the different threats to the pipeline to rank the pipelines within a transmission system relative to each other. The scoring system used values based upon subject matter expert opinion and experience, and therefore, the model was not a true statistical model. A true statistical model, or probabilistic model, had not yet been developed for the industry due to its complexity. Therefore, the relative model provided the best method to assess risk and is what the Company has been using.

In the last several years probabilistic models have been developed, and show great promise as a tool in more accurately assessing pipeline risk. The use of a model that is

entirely data driven provides a more accurate representation of the risks associated with pipelines. This in turn will allow the Company to more precisely mitigate risks associated with its transmission system to improve customer safety and reliability. While the inputs of the model are data driven, the model results will still require subject matter expert interpretation, verification, and understanding of those results. The Company has completed extracting, transforming, and loading of the data in addition to the asset configuration, training, and testing of the probabilistic risk model. The first run of the model was completed in 2023, The probabilistic risk model is utilized to prioritize work, to ensure the urgency of action taken is appropriate to mitigate the threats on that segment, and to ensure the correct mitigative actions are taken to ensure safe operation of the asset. This is a fully quantitative approach to risk modeling allowing an objective view of the risk, threats, and impacts related to the gas assets. The Company intends to implement probabilistic risk models in the future for other asset classes so that risk and risk reduction measures can be prioritized across the entire system using a more common scale, beginning with Storage assets with the probabilistic risk model implementation complete by year end 2024.

**Q. Please explain the development of the Pipeline Integrity Transmission O&M expenses.**

A. As shown on Exhibit A-58 (MPG-1), line 4, the Company's Pipeline Integrity - Transmission O&M expense was $17,089,000 in 2023, and is projected to be $22,275,000 in 2024, $23,110,000 in 2025, and $17,128,000 for the test year ending October 31, 2026. The mileage the Company intends to inspect in 2023 through 2026 is shown in Table 1 below. The O&M cost projections for remediation digs are based upon recent inline

inspection results. The O&M includes costs for inspections, remediation, and where applicable material verification and MAOP reconfirmation.

**Table 1**

| Inspection Mileage | | | |
|---|---|---|---|
| 2023 | 2024 | 2025 | 2026 |
| 266.5 | 374.6 | 320.7 | 206.4 |

Additionally, there are certain baseline assessments on longer pipeline segments that will lead to additional digs. These expenses were not projected utilizing inflation factors.

Consumers Energy recognizes there is risk related to public safety and employee safety on pipelines outside of HCA, and is inspecting and remediating those segments, which are also included in the expenses in this program. Through previous inspections performed on non-HCA segments of pipeline, the Company has been able to gather additional data regarding the integrity of its overall transmission system. Similar anomalies are found in both non-HCA and HCA because the pipeline characteristics are the same. The data shows that most of the anomalies found and remediated on Consumers Energy's transmission system are in non-HCA.

**Q. Are there additional activities included in the Company's Pipeline Integrity Transmission O&M expenses?**

A. Yes. The Company's projection also includes the performance of geohazard assessments of the Company's transmission pipeline systems. These geohazard assessments will provide additional information on potential geohazard outside force threats to the Company's transmission pipelines. This additional information will inform the Company's risk/threat assessments and potential mitigative measures the Company can

take to minimize those threats on the transmission system. Included in the projection is additional material testing on remediation digs where the Company does not have all necessary material properties as required by the Material Verification section of the Safety of Gas Transmission Pipelines: MAOP Reconfirmation, Expansion of Assessment Requirements, and Other Related Amendments rule.

The Company's projection also includes the performance of bending strain analyses and pipe movement studies. Additionally, running Electro Magnetic Acoustic Transducer ("EMAT") tools on pipelines that are susceptible to SCC is part of this projection. Through the use of EMAT tools, the Company has detected and remediated different anomalies than what has previously been found using more traditional ILI tools.

**Q. Please describe the Pipeline Integrity – TOD Program.**

A. In addition to ILIs and remediation on the transmission system, the Company performs assessments of TOD pipe. These pipeline segments are operated on the distribution system above 20% Specified Minimum Yield Strength and thus are covered under the Transmission regulations. As shown on Exhibit A-58 (MPG-1), line 3, the Company's Pipeline Integrity – TOD Program O&M expenses were $812,000 in 2023, and is projected to be $1,059,000 in 2024, $1,085,000 in 2025, and $1,420,000 for the test year ending October 31, 2026. For pipe within HCA, the Company assessed 14.8 miles in 2023 and will assess 15.6 miles in 2024, 23.1 miles in 2025, and 11.8 miles in 2026. Assessments include inspection digs for External Corrosion Direct Assessment ("ECDA"), inspection digs for Internal Corrosion Threat Evaluation, or Internal Corrosion Direct Assessment ("ICDA"). Dig locations are determined from analysis of survey and historical corrosion issues. In addition, starting in 2023, the Company began performing ECDA assessments

on non-HCA segments to reduce overall risk on TOD assets. The additional survey and assessment digs are why there is an increase in O&M expense between 2023 and 2026. The indirect surveys needed to perform the direct assessments are included in the O&M expense. Also, ECDA digs that result in coating repairs only, verification digs, and additional assessments on non-HCA pipelines are included in the projection.

**Q. Please explain the development of the Pipeline Integrity - Transmission capital expenditures.**

A. As shown on Exhibit A-60 (MPG-4), line 1, the capital expenditures for this program were $16,148,000 in 2023, and are projected to be $13,381,000 in 2024, $10,504,000 for the 10 months ending October 31, 2025, and $5,144,000 for the 12 months ending October 31, 2026, as set forth on this exhibit on line 1, column (b); line 1, column (c); line 1, column (d); and line 1, column (f), respectively.

Pipeline Integrity - Transmission expenditures include remediation of pipeline anomalies where 50 feet or more of pipe is replaced, the installation of Ultrasonic Thickness ("UT") sensors, corrosion coupons, and robotic ILIs. Both UT sensors and corrosion coupons allow the Company to measure and determine the corrosion rate to determine current condition and potential replacement. Internal UT sensors physically measure the pipe wall and allow the Company to obtain this information without physically digging up the location. This reduces the need to re-excavate the same locations every seven years to evaluate the condition of the pipe as would be required if the sensor was not installed, thus reducing costs to determine the integrity of the pipe at that location. Corrosion coupons (external corrosion) tell the Company the corrosivity of the soil and the

adequacy of the cathodic protection to help ensure system integrity. The Company anticipates 15% of the remediation digs will be capital.

**Q. Please explain the development of the Pipeline Integrity – TOD Program capital expenditures.**

A. As shown on Exhibit A-60 (MPG-4), line 2, the capital expenditures for this program were $9,274,000 in 2023, and are projected to be $6,119,000 in 2024, $5,593,000 for the 10 months ending October 31, 2025, and $9,998,000 for the 12 months ending October 31, 2026, as set forth on this exhibit on line 2, column (b); line 2, column (c); line 2, column (d); and line 2, column (f), respectively.

As part of the direct assessments performed, UT sensors (for internal corrosion) and UT coupons (for external corrosion) are frequently installed to monitor corrosion rates. The corrosion rate information is then reviewed and evaluated to determine the effectiveness of corrosion control measures. To date, approximately 1,457 UT sensors and 916 UT coupons have been installed. Typical remediation of pipe found during the inspections involves pipe replacements.

**Q. Are there any additional details you would like to provide regarding significant projects included in the Pipeline Integrity – TOD Program?**

A. Yes. In 2023, new requirements were implemented that increased requirements for ICDA assessments. These changes increased the number of excavations required to complete an ICDA assessment. While there was an increase in dig requirements, installation of UT sensors during prior assessment digs reduce the total number of excavations being perform since many of the required locations were already being monitored.

## B. CORROSION CONTROL – TRANSMISSION PROGRAM AND CATHODIC COMPRESSION, STORAGE, AND PIPELINE PROGRAM

**Q. Please describe the Corrosion Control – Transmission O&M Program.**

A. The O&M expense for the Corrosion Control – Transmission Program was $947,000 in 2023, and is projected to be $1,505,000 in 2024, $1,955,000 in 2025, and 2,210,000 for the test year ending October 31, 2026, as shown on Exhibit A-58 (MPG-1), line 2. O&M expenses for corrosion control on the transmission system include special projects like large atmospheric painting projects, pipeline recoating projects, shorted casing remediation and close interval surveys. Similar to the capital program (Cathodic Protection – Compression, Storage and Pipeline), O&M projects are typically identified during yearly surveys and typically occur in a short timeframe. The Company's projected expense amount is based on historical averages (100 miles of close interval survey), the re-coating of pipeline sections that have poor coating conditions based on the close interval surveys, and work to clear shorted casings. The projected expense also includes additional atmospheric painting projects at sites that have not been painted in several years and that have had numerous small touch-ups done to prevent corrosion. This additional work will not only allow the Company to continue to meet the regulatory obligations for corrosion control, but also will ensure and enhance the safety of its natural gas delivery systems. These expenses were not projected utilizing inflation factors.

**Q. Please describe the Cathodic Compression, Storage, and Pipeline Capital Program.**

A. The Cathodic Compression, Storage, and Pipeline Capital Program allows the Company to maintain compliance with federal regulations for cathodic protection of facilities. As shown on Exhibit A-60 (MPG-4), line 3, the capital expenditures for the Cathodic

Compression, Storage, and Pipeline Capital Program were $5,931,000 in 2023, and are projected to be $6,526,000 in 2024, $5,779,000 for the 10 months ending October 31, 2025, and $6,649,000 for the 12 months ending October 31, 2026, as set forth on this exhibit on line 3, column (b); line 3, column (c); line 3, column (d); and line 3, column (f), respectively. The capital activities included in this program are the installation of new or replacement rectifiers and anode beds, the installation of UT Coupon Test Stations and Remote Monitoring Units ("RMUs"), installation of Alternating Current ("AC") mitigation, the installation of insulators, and installation of permanent UT sensors and coupons for monitoring corrosion rates for its Transmission system. The projects undertaken are identified during yearly routine inspections of the cathodic protection systems. When issues are identified, like pipe-to-soil potentials below criteria, repairs typically must occur within one year of identification. As such, the dollar amounts identified for these programs are based on historical averages. One area that has increased in this program is the installation of AC Mitigation. These projects are intended to mitigate stray AC voltages on the pipeline that can cause corrosion or a shock hazard. Additionally, new rules implemented by PHMSA in 2022 require additional testing and mitigation for possible stray current issues. As a result of these additional requirements, the Company has increased monitoring and identified projects to mitigate stray AC voltages.

### C. MAOP COMPLIANCE PIPELINE PROGRAM AND MAOP TRANSMISION PROGRAM

**Q. Please describe the MAOP Compliance Pipeline Program.**

A. The MAOP Compliance Pipeline Program involves MAOP verification and remediation of the Company's transmission pipelines, including Transmission Operated by Distribution pipelines. This work initially began in 2012, in response to the Pipeline Safety, Regulatory

Certainty, and Job Creation Act of 2011, which required the PHMSA to direct each owner or operator of a natural gas transmission pipeline and associated features to provide verification that their records accurately reflect a pipeline's MAOP. This will improve compliance with state and federal pipeline records requirements and confirm historic system MAOP values. On October 1, 2019, PHMSA published the Safety of Transmission & Gathering Lines Rule which codifies the requirement for MAOP establishing documentation to meet traceable, verifiable, and complete criteria. This rule is also identified starting on page 83 of the SEA, which states:

> In 2016, PMHSA published a proposed rulemaking titled "Pipeline Safety: Safety of Gas Transmission and Gathering Pipelines" to update 49 CFR Part 192. This proposed rule included significant changes to the transmission integrity management requirements, along with other general changes to transmission and gathering pipelines with enhancements to the following areas:
> 1. Re-establishing maximum allowable operating pressure.
> 2. Verifying material properties.
> 3. Performing integrity assessments outside of high-consequence areas.
> 4. Management of change enhancements.
> 5. Corrosion control enhancements.
> 6. Modifying the regulation of onshore gas gathering lines.

**Q. How will the Company verify and adequately document the MAOP of these pipelines?**

A. This will be accomplished with a detailed engineering analysis or Standardized Engineering Analysis of the Company's Transmission System. The analysis will determine where work is required to meet the traceable, verifiable, and complete criteria, and upgrade the documentation archiving from a historical perspective to a newly developed engineering content management database integrated with the Company's geospatial information system database. The record database will link record files to the data mined from those records and entered into the geospatial information database for

MAOP calculation from those design and testing values. For each transmission pipeline segment identified as not meeting the record criteria established by the newly published rule, the Company will address these segments through an engineering evaluation that will consider the six regulatory methods of MAOP Reconfirmation identified in 49 CFR 192.624 in conjunction with a solution that provides benefits in regard to pipeline safety, reliability, and deliverability. The six methods are:

1. Pressure Test;
2. Pressure Reduction;
3. Engineering Critical Assessment;
4. Pipe Replacement;
5. Pressure Reduction for Pipeline Segments with Small Potential Impact Radius; and
6. Alternative Technology.

Material verification will require a management program for identifying pipeline segments for which the material property value documents necessary to calculate MAOP are not Traceable, Verifiable, or Complete. The management program will provide identification of those segments for when the Company may expose pipe for purposes other than the 49 CFR 192.614 Damage Prevention Program. When exposed, these segments would require either destructive or nondestructive testing to attain material property values. Evaluation is based on an analysis including, but not limited to, the following factors:

- Nature of the records gap identified (e.g., segments with material verification issues prioritized for replacement);
- Pipeline performance history and pipeline field evaluations;
- Minimizing the impact of service to customers;

- Coordination with other planned work and the need to maintain service to customers; and
- Pipeline location and cost to replace (i.e., population density).

Depending upon the work performed, the project would be an O&M expense or a capital expenditure. The Company's MAOP Reconfirmation capital expenditure projections are based on previously completed work orders of similar magnitude and requirements when pipe replacements are performed. As shown on Exhibit A-60 (MPG-4), line 4, the capital expenditures for the MAOP Compliance Pipeline Capital Program were $4,786,000 in 2023, and are projected to be $51,000 in 2024, $2,409,000 for the 10 months ending October 31, 2025, and $3,016,000 for the 12 months ending October 31, 2026, as set forth on this exhibit on line 4, column (b); line 4, column (c); line 4, column (d); and line 4, column (f), respectively. The projects in 2023 include replacement of piping on Line 1400 underneath Milford Rd and replacement of piping and valves on Line 100A at Mt. Pleasant Station. The capital project planned for 2024 is the retirement of drain piping at the Mt. Clemens City Gate on Line 1060. Capital projects planned for 2025 include the replacement of valves and piping at Metamora City Gate on Line 1900. The Company continues to monitor the gas system for segments without Traceable, Verifiable, and Complete pressure tests to comply with the new PHMSA-published Safety of Transmission & Gathering Lines Rule. Future projects will be identified from the above-mentioned Standardized Engineering Analysis.

**Q. Are there any proposals the Company is requesting the Commission to approve that would impact future expenditures in this program?**

A. Yes. Company witness Heather L. Rayl describes in her direct testimony a request for the Commission to approve the capitalization of hydrotesting of pipelines, in certain

circumstances, to re-confirm the MAOP of these pipelines. The Company does not have any of these projects that would be impacted by this request included in this docket, but anticipates there could be projects in the near future for which it would.

**Q. Please describe the O&M expenses related to the Regulatory Compliance - MAOP Transmission Program as shown on Exhibit A-58 (MPG-1), line 1.**

A. As shown on Exhibit A-58 (MPG-1), page 1, line 1, the O&M expenses for this program were $1,187,000 in 2023, and is projected to be $1,898,000 in 2024, $2,361,000 in 2025, and $2,370,000 for the test year ending October 31, 2026. The test year O&M expense comprises four parts.

The first part is an annual expense of $489,000 for an Aerial population density survey to fulfill the Federal Regulations within 49 CFR 192, more specifically 49 CFR 192.609 and 49 CFR 192.611.

Second, there are two projects occurring on Line 1500 and two on Line 1060 ~~1900~~. These projects involve pressure testing the launcher and receiver barrels at St. Clair compression station, Rochester valve site, Grand Blanc valve site, and Atlas valve site to re-establish MAOP.

The third part of the test year expense is an annual expense of $50,000 for Third Party Coordination Surveys. To limit risk, both physically and/or fiscally, this expense will utilize survey data to collect information to determine location (vertical and horizontal) during the pre-planning period. The information gathered through survey data can proactively provide details of Company facilities and will be incorporated into third party plans where potential conflicts can be identified and mitigated prior to the third party construction. This data will primarily be utilized for Asset Relocation projects.

The fourth part of the test year expense is due to expensing the O&M portion of the Standardized Engineering Analysis costs. In 2021, in response to a Staff recommendation in MPSC Case No. U-20650, the Company moved the SEA expenditures to Account 183.2 - Other Preliminary Survey and Investigation Account. The Company is proposing in this proceeding to expense the O&M portion of this account for the 2023 time period, based upon the percentage of orders that resulted in an O&M or capital replacement. The Company proposes to continue the practice of expensing a portion of the Account 183.2 balance in subsequent general rate case proceedings. The capital portion of the account will be allocated to future capital projects. In 2024, the Company expensed $743,971 for the 2022 SEA expenditures. Table 2 below shows the SEA amounts expensed in 2024, and the SEA amount to be expensed in the test year.

**Table 2**

**SEA Expensed in 2024 and the Test Year**

| Year | Direct Cost | O&M % | O&M Cost |
|---|---|---|---|
| 2022 | 1,323,792 | 56% | 743,971 |
| **Amount Expensed in 2024** | | | **$ 743,971** |

| Year | Direct Cost | O&M % | O&M Cost |
|---|---|---|---|
| 2023 | 1,328,265 | 85% | 1,122,384 |
| **Test Year Amount** | | | **$ 1,122,384** |

The projects and expenses in 2024 and 2025, for the MAOP Transmission O&M Program and for the test year are shown in Table 3 below. These expenses were not projected utilizing inflation factors.

**Table 3**

**Regulatory Compliance O&M Expenses by Project**

| Regulatory Compliance - MAOP Transmission O&M Expenses | 2025 | 2026 | 12 Months Ending Oct 31, 2026 |
|---|---|---|---|
| Aerial High Resolution Imagery Survey for Class Location Studies | 489,000 | 489,000 | 489,000 |
| STC-LN 1060 Mt. Clemens LR Pressure Test | - | 369,000 | 322,875 |
| STC-LN 1060 St. Clair LR Pressure Test | - | 341,000 | 298,375 |
| STC - Line 1500 St Clair LR Pressure Test | 350,000 | - | 43,750 |
| STC - Line 1500 Rochester LR Pressure Test | 350,000 | - | 43,750 |
| 3rd Party Coordination Survey Studies | 50,000 | 50,000 | 50,000 |
| MSEA O&M Projects | 1,122,384 | 1,043,645 | 1,122,384 |
| **Total MAOP Transmission Expense** | **2,361,384** | **2,292,645** | **2,370,134** |

Company witness Rayl discusses the reduction to rate base for the 2024 amount.

**Q. Please explain page 2 of Exhibit A-58 (MPG-1).**

A. Page 2 of Exhibit A-58 (MPG-1) presents an illustration of the amounts of the O&M expenses I am sponsoring if one were to apply an inflation rate to the historical O&M expenses. The expenses that I am supporting are based upon the expenses necessary to comply with regulations and improve system safety as described for the programs above, and have not been projected utilizing inflation factors.

## III. CAPACITY/DELIVERABILITY PROGRAM

**Q. Please describe the capital expenditures relating to the Capacity/Deliverability Program as shown on Exhibit A-12 (MPG-2), Schedule B-5.5, line 3.**

A. As shown on Exhibit A-12 (MPG-2), Schedule B-5.5, line 3, the capital expenditures for this program were $308,275,000 in 2023, and are projected to be $270,362,000 in 2024, $133,358,000 for the 10 months ending October 31, 2025, and $170,322,000 for the 12 months ending October 31, 2026. These capital expenditures address needed increases

in transmission pipeline capacity and ensure measurement accuracy, which help ensure adequate capacity and deliverability throughout the system. These expenditures are driven by projects in TED-I, Deliverability Base Field Measurement, Deliverability Base Pipeline, Regulator Stations – Distribution, and Transmission and Storage ("T&S") City Gates as further described below.

**Q. Why are Capacity/Deliverability projects necessary?**

A. Capacity requirements can increase due to changes in customer population density in specific locations, and also because of changes in system requirements. Examples of changes in system requirements include the need to support load and maintain pressure (both base and peak day), as well as the need to ensure pipeline configuration to allow for in-line inspection through the Pipeline Integrity Program. Deliverability Program expenditures include city gate and regulation station rebuilds and improvements. This program also includes expenditures for the TED-I projects to ensure continued safe, reliable, and deliverable operation of transmission pipelines. Other project work in this program includes investments to ensure gas quality and gas measurement accuracy. Natural gas quality is critical to ensuring that customers' equipment functions properly and safely. Natural gas measurement accuracy ensures that Consumers Energy is properly measuring and accounting for gas purchased for and delivered to customers, as detailed below.

## A. TED-I PROJECTS

**Q. Please explain the TED-I projects shown on Exhibit A-61 (MPG-5), line 1.**

A. The TED-I projects are focused on maintaining deliverability and integrity, and on improving the ability to control gas flows. As shown on Exhibit A-61 (MPG-5), line 1, the

capital expenditures for the TED-I Program were $216,361,000 in 2023, and are projected to be $146,790,000 in 2024, $20,192,000 for the 10 months ending October 31, 2025, and $19,145,000 for the 12 months ending October 31, 2026. Major projects include replacing transmission pipeline segments that contain higher-risk type pipe to ensure integrity and safe operation. In certain cases, city gate stations may be upgraded to enable abandonment of a pipeline or to reduce pressures on pipeline segments to comply with any new MAOP requirements of replacement pipelines. Also included in TED-I are the installation of Remote Control Valves ("RCVs") and Pressure-Limiting Devices ("PLDs") to control pressure and flows during normal operations and in the event of abnormal operation.

**Q. Please describe Consumers Energy's investments in its natural gas transmission system as part of the TED-I projects and how they benefit customers.**

A. As described in the NGDP, Exhibit A-42 (NPD-1), Section IV.C.2, TED-I pipeline projects improve customer reliability and advance public safety by replacing or retiring higher relative risk pipe segments and, in some cases, increase capacity. Additionally, the replaced pipelines also have enhanced pipeline pressure control and isolation capabilities.

**Q. Please explain the TED-I major pipeline projects.**

A. TED-I major pipeline projects focus on maintaining integrity and deliverability, and include transmission pipeline replacements of higher relative risk pipe to ensure integrity and safe operation. Higher relative risk pipe includes segments with previous anomalies or stress characteristics related to integrity management risk mitigation. Capacity requirements are factored into line replacements to ensure customer deliverability. The major TED-I construction project included in this filing is the Mid-Michigan Pipeline project which was put into service in 2024.

**Q. Please describe the Mid-Michigan Pipeline project.**

A. The Mid-Michigan Pipeline project replaced approximately 55 miles of Line 100A, between Ovid City Gate in Clinton County and Chelsea Interchange in Washtenaw County. The project addresses integrity and deliverability concerns with the current pipeline and increase the diameter of the pipeline, from 20-inch to 36-inch within existing pipeline right-of-way ("ROW").

**Q. Has the Company received Commission approval to construct and operate the Mid-Michigan Pipeline?**

A. Yes. The Commission issued an Order in MPSC Case No. U-20618, on November 19, 2020, approving the Mid-Michigan Pipeline, which authorized Consumers Energy to construct and operate this pipeline.

**Q. Please identify capital expenditures for the Mid-Michigan Pipeline.**

A. Exhibit A-62 (MPG-6), line 1, identifies the total capital expenditures for the Mid-Michigan Pipeline project. The capital expenditures for this project were $201,391,000 in 2023, and are projected to be $145,589,000 in 2024, $6,935,000 for the 10 months ending October 31, 2025, and $389,000 for the 12 months ending October 31, 2026 (please see Table 4 with detailed expenditures by year). In 2023 through October 31, 2026, projected costs will be incurred for construction, engineering and design, environmental assessment, surveying, and real estate. A summary of this information is provided in the Table 4 below:

**Table 4**

**Mid-Michigan Pipeline Annual Projects & Expenditures**

| Year | Segment | Length | Projected Spend |
|---|---|---|---|
| | | | |
| 2023 | Pipeline Construction Phase 1, Additional pipe needed for phases 1 & 2, Stockbridge City Gate & Pleasant Lake City Gate Rebuilds, Long Lead Material Procurement for Phase 2, Engineering, Real Estate, Environmental, Permitting on multiple projects | Approx 30 miles | $201. million (actual) |
| 2024 | Pipeline Construction Phase 2, Restoration on Phase 1, Ovid City Gate Rebuild, Engineering, Real Estate, Environmental, Permitting | Approx 25 miles | $146 million (full year projection) |
| 2025 | Restoration on Phase 2 and EGLE permitting requirements for wetlands & streams | n/a | $7 million (full year projection) |
| 2026 | EGLE permitting requirements & any remaining restoration | n/a | $389 thousand |

Major construction commenced in 2023 and concluded in 2024. Site restoration and environmental monitoring will continue beyond 2024.

**Q. Why was the Mid-Michigan Pipeline project necessary?**

A. The Mid-Michigan Pipeline project is part of the Company's transmission enhancement plan to ensure system safety, integrity, and deliverability. The Line 100A project involved the replacement of 1949 vintage pipe that had demonstrated integrity issues. In May 2015, this line experienced a rupture just north of Chelsea. The project also increased the capacity of the Company's natural gas transmission system. The increased capacity provides a more resilient and flexible system capable of supporting the continued increase in system outage days required by regulatory requirements and other operational maintenance needs.

**Q. What other projects are included in the TED-I Program?**

A. As described above, also included in TED-I are the installation of RCVs and PLDs to control pressure and flows during normal operations, and in the event of abnormal

operation. The installation of these devices is consistent with federal and state guidance. In the SEA, at page 200, the Commission recommended that "utilities continue to conduct analyses to evaluate increasing the number of remote shutoff valve systems in high consequence areas to minimize the impact during emergency events." Further, in April 2022, PHMSA promulgated regulations requiring operators to install automatic shutoff valves or RCVs on new and entirely replaced transmission pipelines as a means of rupture detection and mitigation. Recognizing the significance of these devices, the Company has developed a comprehensive RCV installation plan as outlined in of the NGDP, Exhibit A-42 (NPD-1), Section IV.C.2.

**Q. Please explain the RCV expenditures.**

A. The Company is planning to install RCVs on complete pipeline replacements, such as Line 100A (Mid-Michigan Pipeline Project). The costs for those RCVs are included in the project expenditures. RCVs are also being installed to reduce response time on certain Class 4 locations and Class 3 locations within HCAs to improve public safety. The costs for those RCVs are included in the Deliverability Base Pipeline Program. The valves do not prevent failures from occurring but are intended to minimize the time gas flows after a failure and any subsequent fire that would prevent emergency first responders from entering the impacted area. RCVs reduce the loss of natural gas should a pipeline failure occur and can be operated remotely by Gas Control for potential reduction in response times. RCVs will not close inadvertently due to load changes, purging activities, or failure of sensing lines. In 2023, the Company installed 37 RCVs and is projected to install 17 in 2024, 17 in 2025, and 16 in 2026. These installation numbers represent all RCVs installed in all programs and projects. Exhibit A-62 (MPG-6), line 3, identifies the total capital

expenditures for RCVs not otherwise installed in other programs. The capital expenditures for these RCVs were $2,253,000 in 2023, and are projected to be ($103,000) in 2024, $8,717,000 for the 10 months ending October 31, 2025, and $18,074,000 for the 12 months ending October 31, 2026.

**Q. Please explain the reason for the variability in expenditures for RCVs from 2023 to the test year.**

A. As explained above, RCVs are also installed in other programs and projects. In 2023, nine RCVs were commissioned (programming and remote testing) but installed in 2022. There were also 18 RCVs installed as part of the Mid-Michigan Pipeline project. In 2024, all of the RCVs installed were either on the Mid-Michigan Pipeline or in the Deliverability Base Pipeline program. In 2025, many of the RCVs are being installed alongside other projects so some of the costs are shared with those projects. In 2026, the majority of RCVs will be stand-alone projects with most of cost being charged to the TED-I program.

**Q. Please explain the PLD expenditures.**

A. The PLD installation locations are selected pursuant to 49 CFR 192.619 and 49 CFR 192.195. As modification of the Consumers Energy pipeline system occurred due to class location changes, system additions, and purchases over the years, the MAOPs were impacted. Historically, Consumers Energy's Gas Transmission System used pressure drop on pipelines when related to MAOP pressures differences, as outlined within 49 CFR 192.619 and 49 CFR 192.609(e), which states that: "[t]he maximum actual operating pressure and the corresponding operating hoop stress, taking pressure gradient into account, for the segment of pipeline involved;". Additionally, Consumers Energy's Gas Control Operations used remotely operated valves for MAOP protection of the Company's

system. As technology has advanced, the industry has recognized that a better and safer way to control pressures is through the use of on-site overpressure protection devices using a pressure-regulated monitor valve/worker valve arrangement, commonly referred to as PLDs. These configuration enhancements automate the device and allow for quicker response and improved safety on the gas transmission system. Public safety risk is reduced when PLD equipment is installed, which is reliable and adequately protects against potential over pressurization. The Company continually analyzes the pipeline system for areas where the operational safety of the system should be enhanced. As a result of this analysis, the Company identified a need to install PLDs and established a prudent plan to improve the system and customer safety. The 2023 projects included:

- Line 4060 Vector Hartland, Howell;
- Line 1200A CE-ANR Stag Lake, White Pigeon; and
- Line 2700 Squirrel Rd Valve Site, Lake Orion;

The installation of PLDs improves the operation of the system and provides enhanced public safety. Exhibit A-62 (MPG-6), line 2, identifies the total capital expenditures for PLDs. The capital expenditures for PLDs were $12,156,000 in 2023, and are projected to be ($133,000) in 2024, $0 for the 10 months ending October 31, 2025, and $0 for the 12 months ending October 31, 2026. The PLD installation program was completed in 2024.

**Q. What other projects are included in the TED-I Program?**

A. Also included in this program are projects that are smaller in scope and related to other TED-I projects that are not RCVs nor PLDs. These include valve site junctions so the Company can use the existing pipelines for outage or other emergent situations and final

restoration, property acquisition, and closure of environmental permit requirements related to completed pipeline and other major projects. As part of this program the Company is planning a transmission interconnect with DTE Gas Company in 2025 that will improve overall system resiliency to benefit customers of both utilities. Exhibit A-62 (MPG-6), line 4, identifies the total capital expenditures for Pipeline & Other Installations/ Modifications. The capital expenditures for these projects were $561,000 in 2023, and are projected to be $1,437,000 in 2024, $4,540,000 for the 10 months ending October 31, 2025, and $682,000 for the 12 months ending October 31, 2026.

**Q. Please provide further information concerning the transmission interconnect project.**

A. The transmission interconnect project, which the Company calls the Oakland Resilience Interconnect, is a project the Company is coordinating with DTE Gas and is for the benefit of both utilities' customers. This project is part of the Company's response to Natural Gas Recommendations for Mitigating Risk, found within the SEA. Once built, this facility will allow either utility to provide natural gas to the other utility to address an emergency, as defined in 18 CFR 284.262, that poses a risk to the ability to provide natural gas service for customers in the State of Michigan. Natural gas supply through this interconnect in response to an emergency will be provided in a best-efforts manner. DTE Gas and Consumers Energy received a certificate of necessity to construct and operate the interconnect through an Act 9 filing on October 10, 2024 in Case No. U-21510. The Commission approved the capital spending for DTE Gas Company's portion of the interconnect in its order in Case No. U-21291 on November 7, 2024. The Company's capital expenditures for this project were $53,000 in 2023, and are projected to be $1,161,000 in 2024, $4,466,000 for the 10 months ending October 31, 2025, and $45,000

for the 12 months ending October 31, 2026. These expenditures are included in the Pipeline & Other Installations/ Modifications expenditures discussed above.

## B. DELIVERABILITY BASE FIELD MEASUREMENT PROGRAM

**Q. Please describe the Deliverability Base Field Measurement Program investments.**

A. The Deliverability Base Field Measurement Program is essential to ensure accurate gas quality and measurement. Exhibit A-61 (MPG-5), line 3, identifies the total capital expenditures for the Deliverability Base Field Measurement Program. The capital expenditures for this program were $5,319,000 in 2023, and are projected to be $6,774,000 in 2024, $10,255,000 for the 10 months ending October 31, 2025, and $19,890,000 for the 12 months ending October 31, 2026. Field measurement projects are associated with remote gas measurement equipment monitoring, gas volume calculations, gas transmission metering, Transport Metering Stations ("TMS"), Interstate Interconnection sites, gas quality improvement and processing, gas sampling systems, and other ancillary equipment. These investments directly impact the Company's ability to conform to the MPSC technical standard requirements concerning natural gas quality, measurement accuracy, and Lost and Unaccounted For ("LAUF") gas. Additional projects in this program include measurement equipment upgrades that allow for improvements in American Gas Association volume calculation algorithms, fuel usage report automation, and transducer replacements. The placement of measurement facilities and equipment at appropriate locations can assist in reducing LAUF gas volumes and improve gas quality monitoring. For additional information on LAUF, please see the direct testimony of Company witness Timothy K. Joyce.

**Q. Are there any other activities involved in the Deliverability Base Field Measurement Program?**

A. Yes. The Deliverability Base Field Measurement Program also involves the installation of meter facilities to validate delivery volumes from interstate suppliers. These projects help improve measurement accuracy of volumes received. The Company is also installing gas quality and gas processing equipment such as chromatographs and water and hydrogen sulfide analyzers to verify gas received from suppliers or withdrawn from storage meets the requirements of pipeline quality gas in accordance with regulatory requirements. The Company is also planning to construct the Williamston Transmission Meter Proving, Testing, and Development Station in the test year. This station will allow a testing environment for gas transmission measurement technology to comply with API-1164, which requires any new protocol, application, or software proposed to be added to the Supervisory Control and Data Acquisition ("SCADA") network should be run in a test-bed or development environment to evaluate the potential for impairing the performance of the SCADA system. Further, the Transportation Security Administration ("TSA") requires the management of software/credentials on measurement devices and a physical testing laboratory with functional versions of all equipment subject to hardware/firmware upgrades to enable testing/validation of firmware in a controlled/non-production environment. The Company currently does not have a test environment for transmission meters or gas analytical equipment.

Major projects included in this filing include:

- Chelsea Meter Replacement. Project year 2023;
- Summerton Road Gas Quality, valve replacement and metering upgrades. Project year 2023;

- White Pigeon 1200A Meter Installation. Project year 2024;
- Lahser USM Installation. Project year 2025;
- Perry Morrice USM Installation. Project year 2025;
- Laingsburg LN 400 Meter Installation. Project year 2025;
- Grand Blanc LN 500 Meter Installation. Project year 2025;
- Rose Center City Gate Meter Replacement. Project year 2026;
- Northville Line 1200A Meter Installation. Project year 2026;
- Chrysler Tech Meter Upgrade. Project year 2026;
- SCADA Gas Quality Hydraulic Modeling. Project year 2026;
- Eureka City Gate Meter Upgrade. Pre-engineering 2026 and Project year 2027;
- Williamston City Gate Chromatograph Upgrade. Pre-engineering 2026 and Project year 2027;
- Winterfield 12 Chromatograph Upgrade. Pre-engineering 2026 and Project year 2027; and
- Ovid Chromatograph Upgrade. Pre-engineering 2026 and Project year 2027.

### C. DELIVERABILITY BASE PIPELINE PROGRAM

**Q. Please explain the Deliverability Base Pipeline expenditures.**

A. The Deliverability Base Pipeline expenditures support maintaining operations in accordance with the Michigan Gas Safety Standards ("MGSS"). Types of projects include: (i) the replacement of valves, and if necessary, the associated valve operators, when inspection determines that the valves no longer perform as needed, which may mean valves no longer turn or they may not fully seal off the flow of gas (MGSS Rules 192.145, 192.150, 192.179); (ii) the replacement of piping due to MAOP revisions identified as a result of class location changes (49 CFR 192.5 and 192.611); (iii) construction of new sectionalizing valves and tap valves to improve system deliverability, and help meet valve

spacing requirements defined by 49 CFR 192.179; (iv) reconfiguration of tap piping (i.e., laterals) and associated valving upstream of city gate facilities as companion projects to city gate rebuilds; and (v) installation or retirement of pipeline taps to TMS facilities being attached to the Company's system. Exhibit A-61 (MPG-5), line 4 identifies the total capital expenditures for the Deliverability Base Pipeline Program. The capital expenditures for this program were $18,757,000 in 2023, and are projected to be $18,173,000 in 2024, $19,403,000 for the 10 months ending October 31, 2025, and $25,023,000 for the 12 months ending October 31, 2026.

**Q. Please explain why the Deliverability Base Pipeline expenditures have increased in recent years.**

A. The Deliverability Base Pipeline expenditures have increased from historical levels due to a number of factors. In 2019, the Company began conducting annual aerial surveys to enhance the GIS data set to provide more accurate building data along with more accurate occupancy data. There have been a number of class location changes indicated by the aerial survey. Per 49 CFR 192.611, these are segments of pipeline that need to be replaced within 24 months of the change in class location in order to operate the pipeline under the published MAOP. These segment replacements are included in the projection for this program.

Secondly, the Company began conducting annual system wide valve spacing studies in 2021 that review each Transmission Pipeline segment against the current class location to determine if the pipeline segments are in compliance with 49 CFR 192.179. These studies identify the valve(s) required to be compliant with 49 CFR 192.179.

## D. REGULATOR STATIONS - DISTRIBUTION

**Q. Please describe the regulator station investments.**

A. Distribution regulator stations reduce pressure supplied from a higher pressure distribution system to another with a lower pressure distribution system. For example, a regulator station could be used to supply a medium pressure (60 psig MAOP) system from a high pressure system (400 psig MAOP). Exhibit A-61 (MPG-5), line 5, identifies the total capital expenditures for the Regulator Station Program. The capital expenditures for this program were $36,262,000 in 2023, and are projected to be $45,690,000 in 2024, $36,039,000 for the 10 months ending October 31, 2025, and $47,274,000 for the 12 months ending October 31, 2026. The scope of the expenditures in this program is aimed at maintaining the integrity of 648 regulator stations. Additional benefit is realized by the modernization of the fleet of regulator station through the reduction of unintended methane emissions. The Company's regulator station installation plan is further described in Section IV.D.6 of the Company's NGDP, Exhibit A-42 (NPD-1), sponsored by Company witness Dreisig. The Company currently has 94 odorizers, which are considered distribution assets funded as part of this program as well, despite the fact that they are often co-located at city gate sites. These odorizers add odor to the downstream gas systems, which is a critical safety element and is required by code (49 CFR 192.625). Planned projects, location, and project type are listed below. This program also funds emergent issues, as well as SCADA installations, retrofitting of existing gas heaters with modern burner management systems ("BMS"), installation of slam-shut overpressure protection devices and electrical improvements at regulator stations. Investments being made to regulator stations improve employee safety and ergonomics. Regulator stations located in

pits may be difficult to enter and pose risk for operators. These projects are selected based on discussions with subject matter experts and major stakeholders, which include Operations and Engineering, but are also based on asset performance and age of the facility. The major projects in this filing include:

**2023**

- Verlinden & Shiawassee (Rebuild -Lansing);
- Montrose & Ridgeway (Rebuild – Mount Morris Twp);
- Riverside Dr. (Rebuild – Ionia);
- 21st & Jefferson (Rebuild – Bay City);
- Columbus & Trumbull (Rebuild – Bay City), Functional replacement of 10th & Trumbull;
- Cedar Lake (Rebuild – Day Twp);
- Marshall-Butterfield (Rebuild – Olivet);
- Chicago & Ballenger (Rebuild – Flint); and
- St. Clair Line 1060 distribution odorizer (Rebuild – Ira).

**2024**

- 21 Mile & Romeo Plank Rd. (Rebuild – Macomb Twp);
- Selfridge – Rosso Hwy. (Rebuild – Mt. Clemens);
- Ithaca Reg Station (Rebuild – Ithaca);
- State & Hemmeter (Rebuild – Saginaw);
- Grand River & Mechanic (Rebuild – Williamston);
- Lake Lansing & Rutherford (Rebuild – East Lansing);
- Attica & Lake Pleasant (Rebuild – Attica Twp); and
- Plainwell Valve Site Odorizer (Rebuild – Plainwell).

**2025**

- Hotchkiss & M-84 (Rebuild – Bay City);
- Poseyville (Rebuild – Midland);
- Center & Boltwood (Rebuild – Hastings);
- Hogsback & Pryor (Rebuild – Mason);
- Sheridan & Lansing (Rebuild – Gaines Twp.);
- Silver Lake & Dixie (Rebuild – Waterford Twp.);
- Gardner & 7 Mile (Rebuild – Northville); and
- Clintonia Rd. Valve Site Odorizer (Rebuild – Danby Twp.)

**2026**

- Pitcher & Lovell (Rebuild – Kalamazoo)
- Shepherd & Horatio (Rebuild – Charlotte)
- Sohn Rd. Regulator St. (Rebuild – Vassar)
- Corunna Ave. Regulator St. (Rebuild – Corunna)
- Corunna & M-71 (Rebuild – Corunna)
- Oakland & Sarasota (Rebuild – Pontiac)
- Ruth & Atwater (Rebuild – Ruth)
- Central Odorant Operations Hub (Odorant storge facility – Mid-Michigan).

**E. T&S CITY GATES**

**Q. Please further describe the T&S City Gate investments.**

A. City gate stations are the delineation point between the transmission and distribution systems. Gas pressure is reduced to distribution pressure, often 400 psig or less, through pressure regulation. Over-pressure protection, including relief valves, monitor regulators, or emergency shutdown valves (ESD) are installed at these locations to ensure a safe limit

to pressure in the distribution system exists. Odorizer stations are often installed at city gates; although these are distribution assets, they are co-located due to Federal code requirements (49 CFR 192.625) to odorize distribution systems. Odorizers are funded in the Regulator Station Program unless they are installed as part of a complete city gate rebuild. Exhibit A-61 (MPG-5), line 6, identifies the total capital expenditures for the T&S City Gate Program. The capital expenditures for this program were $31,320,000 in 2023, and are projected to be $52,913,000 in 2024, $47,469,000 for the 10 months ending October 31, 2025, and $58,991,000 for the 12 months ending October 31, 2026. The scope of the city gate program allows for the rebuilding or other improvements to existing city gate facilities to ensure system reliability and in response to increased customer load demands. City gate stations allow for certain system safety controls during critical system incidents. City gates can have set pressures lowered or increased to restrict flow into the distribution system, allowing for a greater degree of security, redundancy, and resiliency. Valves, including installation of over pressure protection such as an Emergency Shut-Down Valve ("ESD"), can also be closed to restrict delivery as a mitigation if serious situations develop and to prevent an MAOP exceedance. The Company has developed a city gate work plan as outlined in Section IV.C.2 of the Company's NGDP, Exhibit A-42 (NPD-1). As identified in the NGDP, many city gates are 40 to 50 years old. This makes it challenging to acquire parts and rebuild material for the critical equipment located within the city gate. These projects are selected based on discussions with subject matter experts and major stakeholders, which include Operations and Engineering, but are also based on asset performance and age of the facility. This program also includes expenditures for heater and separator reliability projects. Additionally, this program funds remote terminal

units ("RTU") and electrical improvements at transmission sites, which include replacing or updating RTUs, safety measures associated with lighting, gas detection, or security, and other modernization electrical and instrumentation efforts. Obsolete programming logic controllers also require replacement due to being unsupported and reaching the end of their manufactured recommended life. Many of the City Gates contain this legacy equipment which will need to be updated to modern equipment to prevent downtime in the event of a failure. As emergent projects arise, priority is given to the most important to help ensure safety and reliability, which can result in deferring a planned project. The major city gate projects in this filing include:

**2023**

- Akron City Gate (Rebuild - Akron);
- Galesburg City Gate (Rebuild – Galesburg);
- Kalamazoo – M Ave City Gate (Rebuild - Kalamazoo); and
- Pontiac Walton ESD (Auburn Hills).

**2024**

- Excelsior City Gate (Pipe install and City Gate Retirement - Excelsior);
- Orion City Gate (Rebuild - Lake Orion);
- Leonard-Lakeville City Gate (Rebuild – Leonard);
- Blissfield Panhandle Eastern Pipeline ("PEPL") City Gate (Rebuild - Blissfield);
- Dorr City Gate (Partial Rebuild & Modernization - Dorr);
- Jackson Park Rd City Gate (ESD Installation & Electrical Upgrade) - Jackson); and

- Laingsburg City Gate (ESD Installation & Electrical Upgrade - Laingsburg) ;

**2025**

- Bancroft City Gate (Rebuild - Morrice);
- Lahser City Gate (ESD Installation & Electrical Upgrade - Beverly Hills);
- Flint Torrey City Gate (Rebuild - Flint);
- Macomb City Gate (ESD Installation & Electrical Upgrade - Macomb)
- Hanover Horton City Gate (Rebuild);
- Jackson Hart PEPL City Gate (Rebuild);
- Highland City Gate and odorizer (Rebuild); and
- Overisel Compression (Electrical Upgrade)

**2026**

- Novi-Wixom City Gate (ESD Installation and modernization);
- Spring Arbor PEPL City Gate (Rebuild);
- Flint CG Irish Rd City Gate;
- Dixie Waterford (ESD Installation & Electrical Upgrade);
- Climax City Gate (Rebuild);
- South Lyon – Whitmore Lake City Gate (Rebuild);
- Mendon Leonidas City Gate (Rebuild); and,
- Northville Compression (Electrical Upgrade)

## F. MISCELLANEOUS TRANSMISSION AND COMPRESSION

**Q. Please explain the Miscellaneous Transmission and Compression Expenditures shown on line 2 of Exhibit A-61 (MPG-5).**

A. This line represents legacy expenditures in programs no longer used, and final settlement costs for projects as they are closed out. In 2023 and 2024, the expenditures are for legacy program costs related to measurement and regulation projects.

**Q. Are there contingency costs included in these capital expenditures?**

A. No. Although it is a common and prudent practice to include project contingency costs for these types of projects, and is recognized as an accepted Project Management practice, especially when contingency covers the expansion of work approved, contingency costs have not been included in these projections. While contingency costs are a real item in a project estimate, like any other cost, and should be included in estimates of major projects, due to past Commission orders concerning the inclusion of project contingency, the Company has not included those costs in this filing.

**Q. Please describe Exhibit A-63 (MPG-7).**

A. Exhibit A-63 (MPG-7), in accordance with Attachment 11 to the filing requirements prescribed in Case No. U-18238, provides the variances in the capital program amounts for the distribution and transmission programs, which I sponsored in the Company's most recent general gas rate case, Case No. U-21490.

**Q. Can you explain why columns (c), (d), (e), and (f) of Exhibit A-63 (MPG-7), do not contain any data?**

A. Yes, the information for column (c), the "Last Rate Case Approved Spending Plan Case No. U-21490," cannot be provided because Case No. U-21490 resulted in a settlement

agreement that did not specifically state approved capital spending amounts for the programs I am supporting. Thus, column (c), the "Last Approved Spending Plan" cannot be calculated. Since there is no data to display in column (c), the information for columns (e) and (f) that seek information concerning the variances from (c), cannot be completed. As for the information for column (d), the "Actual Spending in the Test Year," cannot be completed as the test year in Case No. U-21490, which was the 12 months ending September 30, 2025, is a time period that has yet to transpire as of the filing of this case.

**Q. Can you summarize your direct testimony?**

A. Yes. The three programs described in my direct testimony span the major areas of Gas Transmission and Distribution operations. These programs eliminate depth of cover issues and physical conflicts with other utilities to ensure continued safe operation, ensure MAOP verification and remediation of the Company's transmission pipelines, and address needed increases in transmission pipeline capacity, all of which help to ensure adequate capacity and deliverability throughout the system. These investments will help the Company meet its objectives of supplying safe, reliable, affordable, and clean energy to customers as described in the NGDP.

**Q. Does this complete your direct testimony?**

A. Yes, it does.

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

| | | |
|---|---|---|
| In the matter of the application of<br>**CONSUMERS ENERGY COMPANY**<br>for authority to increase its rates for the<br>distribution of natural gas and for other relief. | )<br>)<br>)<br>)<br>) | Case No. U-21806 |

**REBUTTAL TESTIMONY**

**OF**

**MICHAEL P. GRIFFIN**

**ON BEHALF OF**

**CONSUMERS ENERGY COMPANY**

May 2025

**Q. Please state your name and business address.**

A. My name is Michael P. Griffin, and my business address is 4600 Coolidge Highway, Royal Oak, Michigan 48073.

**Q. Are you the same Michael P. Griffin that testified previously in this case?**

A. Yes.

**Q. What is the purpose of your rebuttal testimony?**

A. The purpose of my rebuttal testimony is to address the proposed reductions to Consumers Energy Company's ("Consumers Energy" or the "Company") projected capital expenditures and Operating and Maintenance ("O&M") expenses and the rejection of an accounting treatment change proposed by Attorney General Dana Nessel ("Attorney General") witness Sebastian Coppola. Next, I will provide rebuttal testimony concerning the proposed increases and reductions to the Company's projected capital expenditures and O&M expenses proposed by Citizens Utility Board ("CUB") witness Ram Veerapaneni. Finally, I will provide rebuttal testimony concerning investment levels in future rate case applications and the suggestion that all utility programs should be assessed for risk reduction and cost effectiveness brought forth by Michigan Environmental Council ("MEC") and Sierra Club ("SC") (collectively, MEC) witness Dr. Sol deLeon.

**Q. Are you sponsoring any exhibits with your direct testimony?**

A. Yes, I am sponsoring the following exhibits:

| | | |
|---|---|---|
| Exhibit A-12 (MPG-2) Revised | Schedule B-5.5 | Projected Capital Expenditures Transmission & Distribution Plant - Summary of Actual & Projected Gas Capital Expenditures; |

| | |
|---|---|
| Exhibit A-61 (MPG-5) Revised | Actual & Projected Gas Transmission and Distribution Capital Expenditures - Capacity/Deliverability Program; |
| Exhibit A-135 (MPG-8) | Workpapers, WP-MPG-13, WP-MPG-15, WP-MPG-17 and WP-MPG-19; |
| Exhibit A-136 (MPG-9) | Response to Discovery Request U-21806-CECo-AG_DR2; and |
| Exhibit A-137 (MPG-10) | Response to Discovery Request U-21806-CUB-CE-0248. |

**Q. Were these exhibits prepared by you or under your direction or supervision?**

A. Yes.

**Q. Please describe Exhibit A-12 (MPG-2), Schedule B-5.5 Revised and Exhibit A-61 (MPG-5) Revised.**

A. These exhibits reflect a revision that I am making to my originally filed exhibits and changes I am making to my projections as described in my rebuttal testimony below. Exhibits A-12 (MPG-2), Schedule B-5.5 Revised and A-61 (MPG-5) Revised, reflect adjustments to the Capacity/Deliverability Program and the sub-program Deliverability Base Pipeline. These changes will be further explained in my rebuttal testimony to Attorney General witness Coppola below.

## I. ATTORNEY GENERAL WITNESS COPPOLA

**Q. On page 60, beginning on line 12, through page 61, line 5, of his direct testimony, Mr. Coppola discusses the Company's Pipeline Integrity Transmission Operated by Distribution ("TOD") capital expenditures. He goes on to state that I provided no other details about activities or work volumes to support the forecasted capital expenditures for the TOD program. Do you agree with this assessment?**

A. No, I do not. Included with the Company's initial filing were four workpapers showing Assessment IDs (projects), work dig types, costs, and other information used to develop both the capital and O&M costs for the program for 2023 through 2026. Those workpapers, WP-MPG-13, WP-MPG-15, WP-MPG-17 and WP-MPG-19 are included as Exhibit A-135 (MPG-8).

**Q. On page 61, beginning on line 13, through page 62, line 13, of his direct testimony, Mr. Coppola discusses the Company's casing assessment program. As part of his review, he states that casing assessment is a new category of costs and that "the Company stated that is has very limited experience with the cost of inspecting and remediating casings." Do you agree with his statement?**

A. No, I do not. This is the third time the Company has assessed the casings on the system since the requirement went into effect in 2004. Additionally, his assertion about the Company stating that it has limited experience is not true and this has been acknowledged by Mr. Coppola. I am including Exhibit A-136 (MPG-9) which is the response to discovery request U-21806-CECo-AG_DR2. In his response, Mr. Coppola acknowledges that the Company did not make the statement that it has very limited experience with the cost of inspecting and remediating casings.

**Q. Additionally, as part of his review of the casing assessment program, Mr. Coppola states that the $2.0 million included for assessments in 2025 and 2026 seem to be "ballpark" amounts and that due to the early phase of project development, the test year amount of $2.0 million should be eliminated. Do you agree with this recommendation?**

A. No, I do not. The $2.0 million is based on what the Company has historically needed to complete the assessment of casings. The level of planning and cost to accomplish four examinations is complex and expensive. In order to levelize work and cost, the projects are spread across two years. To assess the casings within the system, the Company surveyed and tested them in 2023. The data is then analyzed, and four casings were selected in 2024 for examination in 2025 and 2026. This examination can happen in one of two ways. Utilizing a robotic In-Line Inspection ("ILI") tool or by removing the pipeline from the casing to physically inspect the pipe. If the pipe has to be physically removed from the casing for inspection, new pipe is inserted into the casing to replace the old pipe. The method of examination depends on the configuration of the pipe and possibility of utilizing a robotic ILI tool. As to Mr. Coppola's concern about the phase of these projects, the planning and scheduling phase is a part of the normal cadence required to meet these code requirements. For the casings within our system to be considered assessed, the 2025 and 2026 work must be completed within seven years of the prior assessment. These projects are on track and Mr. Coppola's proposed test year reduction of $2.0 million for casing assessments should be rejected by the Michigan Public Service Commission ("MPSC" or the "Commission").

**Q. On page 62, beginning on line 14, through page 63, line 7, of his direct testimony, Mr. Coppola discusses the Company's risk mitigation program cost variability and concludes that the Company's test year projection should be reduced by $2.953 million. Do you agree with his reasoning and assessment of the program?**

A. No, I do not. The increase in mileage and cost from 2024 to 2026 is a result of the Company ramping up the program and secure the resources needed to complete more mileage in a single year. In order to align the non-high Consequence area ("HCA") assessments with the HCA assessments, more survey and remediation work would need to be completed than what has been done in prior years. The reason for and importance of this program is shown in Exhibit AG-15 at pages 1 and 2. These assessments will inform the Company of the condition of these pipe segments and improve public safety. A stepped increase in 2024 and 2025 is being used to evaluate and secure the resources necessary for the Company, as well as for the contractors that will be utilized. The increase in 2026 allows the Company to assess all the non-HCA on the pipelines scheduled for assessment that year. In 2024 and 2025, only portions of the non-HCA mileage were assessed for those pipelines. As explained in Exhibit AG-15 (discovery response U21806-AG-CE-0316), performing the non-HCA and HCA assessments together gives the Company a better understanding of cathodic protection of the pipe and allows the Company to address deficiencies in the cathodic protection system more holistically. Risk Mitigation assessments are performed to improve safety of the Company's transmission system by assessing for external corrosion on the pipelines. This will reduce the risk of leaks due to external corrosion and improve the overall safety of the system. For the reasons stated above, Mr. Coppola's

proposed test-year reduction of $2.953 million related to Risk Mitigation assessments should be rejected by the Commission.

**Q. On page 64, beginning on line 10 of his direct testimony, Mr. Coppola discusses proposed reduction of $3,491,000 to rate base for the 2023 and 2024 expenditures for project GL-03042 within the Maximum Allowable Operating Pressure ("MAOP") Pipeline capital program for which the Company has stated it no longer intends to complete the project. Do you agree with this recommendation?**

A. No, I do not. The Company is willing to remove the dollars from rate base for this project, however, workpaper WP-MPG-2 (Exhibit AG-16) is in whole dollars and not thousands. So the rate base reduction for this project should be $3,491 ($1,692 in 2023 and $1,799 in 2024) and not $3,491,000 as proposed by Mr. Coppola.

**Q. On page 63, beginning on line 10 of his direct testimony, Mr. Coppola discusses proposed reductions to the Company's Regulatory Compliance – MAOP Project capital expenditures. In this section, he discusses his assessment of the program and states that the "issues here are the same as in the Distribution MAOP projects." Do you agree with his assessment of the Company's MAOP programs?**

A. No, I do not. Please see the rebuttal testimony of Company witness Lincoln D. Warriner which provides rebuttal to the arguments Mr. Coppola makes concerning the MAOP Compliance programs in general.

**Q. How did the Company decide the most feasible option for the projects you are sponsoring that require reconfirmation under 49 CFR § 192.624?**

A. For the projects requiring reconfirmation, the Company selected an MAOP reconfirmation method that provided benefits beyond compliance for the lack of MAOP Traceable,

Verifiable, and Complete ("TVC") pressure test documentation. For other projects, the Company was able to conduct engineering and construction efficiencies while addressing pressure test documentation issues. Further information about these situations and projects is summarized below. These projects are all shown on Exhibit AG-16.

- For project GL-0341 (STC-LN 1060 Mt. Clemens LR Drain Retirement), the Company selected an MAOP reconfirmation solution that provided benefits beyond compliance for the lack of MAOP TVC pressure test documentation. A part of the gap segment is on a drain line that is not utilized by Company operations employees for liquid removal on the launcher/receiver. The project is opting to retire the drain line instead of re-testing or replacing it and installing a new drain assembly. The remaining portion of the gap along the main line will be re-tested which will be expensed (O&M). The Company evaluated undertaking a pressure reduction on the full gap segment, which was determined to not be feasible due to the negative impacts on gas deliverability to Mt. Clemens city gate. Because of these reasons, it was determined that retirement of the drain line, installation of new drain assembly, and retesting the remaining segment was the best option for safety, delivery, and compliance.

- For project GL-03461 (Line 1900 – Metamora City Gate – Hot Tap Replacement & Mainline Valve Install), the Company selected an MAOP reconfirmation solution that provided benefits beyond compliance for the lack of MAOP TVC pressure test documentation. The project also provides an opportunity to install a new main line valve/dual tap assembly to increase system resiliency during outages and lower the amount of methane released during a partial system outage. Due to the short length of the segment, a pressure test is impractical due to the cost associated with multiple cut-outs and welding required in order to conduct testing. The Company is doing the project in conjunction with other projects on the Line 1900 for efficiency. The Company evaluated undertaking a pressure reduction on this line, but it was determined that this is not feasible due to negative impacts on gas deliverability to/from storage fields and would require additional pressure control devices to be installed. Because of these reasons, it was determined to be in the best interest of safety, deliverability, and compliance for replacement as identified by 49 CFR § 192.624(c)(4).

- For Project GL-03462 (STC-Ln 1060 4" BD Repl), the Company selected an MAOP reconfirmation solution that benefits from construction efficiencies and provides some benefit beyond reconfirmation. Due to the short length of the segment, material verification is impractical as it would require replacement of the whole blowdown ("BD") assembly; it would also require the destruction of the welded end valve in order to obtain a sample. A new flanged end valve will be installed, which will allow for equipment connection during temporary

compression/flaring operations. The new BD assembly will also be designed to meet the current engineering standard. This project will also take place in conjunction with other O&M projects at the site for construction efficiencies (L1060 O&M Pressure test). The Company evaluated undertaking a pressure reduction on the segment, which was determined not to be feasible due to the negative impacts on gas deliverability to the nearby Mt. Clemens city gate, which feeds the distribution system.

- For project B-GL-00289 (2026 project for Capital MAOP Replacement Project), the Company continues to review its records and requires funding to remediate any additional gaps that are discovered in between rate case submittals.

**Q. Are there other reasons these projects are being conducted and should be approved by the Commission?**

A. Yes, there are. Three of the projects shown on Exhibit AG-16, (GL-03197, GL-03210, and GL-03261) are projects for which the Standardized Engineering Analysis research indicated that segments needed replacement due to a class location change that required remediation regardless of TVC records status per 49 CFR § 192.611. Pressure reduction is not feasible as it would not allow the Company to meet gas deliverability requirements. For the reasons stated above, Mr. Coppola's proposed reduction of $3,902,000 for 2023, $2,153,000 for 2024, $1,205,000 for 10 months ending October 2025, and $2,790,000 for the projected test year should be rejected by the Commission.

**Q. On page 65, beginning on line 10, through page 66, line 7, of his direct testimony, Mr. Coppola proposes reductions to several Asset Relocation Transmission Program projects. As part of his analysis, he states that based upon the status of the projects in early March of 2025, the cost level and timing of the capital expenditures is still uncertain and premature to include in rate base. Do you agree with this assessment and reason?**

A. No, I do not. Each of these projects are progressing and have undertaken activities commensurate with projects that will be constructed in 2026. Company engineers primarily manage projects being constructed in the current year up until late spring when these projects start to be released for construction. They then begin to work on projects for the next year which would include pre-engineering work such as SAP order creation, design commencement, environmental reviews, and long lead-time material ordering. Then they meet with gas control on when the projects can be done based on all other project work and system demands which determines the final scheduling of construction. Thus, Company engineering sources utilize a prudent cadence prior to construction. Further, the timing of and cost of these projects is shown in Exhibit AG-17 (workpaper WP-MPG-1). The Company continues its normal cadence with these projects which also accounts for overall program risk and which ensures continued safety of the system. Mr. Coppola's recommendation that these projects are too premature to include in rate base and should be rejected by the Commission and the Company's full projection for the Asset Relocation Transmission Program should be approved by the Commission.

**Q. On page 67, beginning on line 1, through page 67, line 19, of his direct testimony, Mr. Coppola proposes that the Commission disallow the expenditures for project GM-01047 JXN-Lainsburg Jnc. Meter Installation in the Deliverability Base Field Measurement Program based upon his review. Do you agree with this assessment and reason?**

A. No, I do not. This project is at a major interstage where multiple large Company-owned pipelines intersect. Having the available metering data will improve measurement accuracy, and associated reports to identify losses on the system earlier as identified in the benefits that were previously described in discovery response U21806-AG-CE-322-Griffin_ATT_1 (Exhibit AG-18). This investment will allow the Company to continue to conform to the MPSC technical standards described in my direct testimony on page 39, lines 15 through 17. Mr. Coppola's recommendation should be rejected by the Commission and the Company's projection for this project should be approved by the Commission.

**Q. On page 68, beginning on line 1, through page 69, line 7, of his direct testimony, Mr. Coppola discusses the Deliverability Base Field Measurement Program. As part of his analysis, on page 68, beginning on line 10, through page 68, line 14, of his direct testimony, Mr. Coppola discusses the $100,000 annual savings the Company would experience with gas analysis buildings that are part of project GM-01089, Williamston Meter Proving Station. Do you agree with his assessment?**

A. No, I do not. Mr. Coppola seems to be confusing the Company's physical, permanent building at the site with multiple gas analysis buildings that will be constructed at this site. The $100,000 savings is not from using Company resources to build the Company building

in Williamston Michigan called the Williamston Meter Proving station facility. This is savings from constructing the multiple gas analysis buildings that is described beginning on page 68, line 19 of Mr. Coppola's direct testimony. The savings identified is from utilizing Company internal resources versus relying on third-party resources. Third-party contractors labor rates are significantly higher than the Company, and the third-party contract includes charges for project management, master electrician/journeyman, laborers, and costs for tools and equipment. The Company would only incur costs for labor as the project management and master electrician/journeyman costs would be leveraged by increasing the scope of work of existing licensed and experienced salaried employees.

**Q. On page 68, beginning on line 14, through page 68, line 17, of his direct testimony, Mr. Coppola discusses the $50,000 annual efficiency from the Company building a Gas Sampling Site at the Williamston Transmission Meter Proving Station, which would eliminate the need for a vendor's sampling site. He concludes that the analysis is incomplete. Do you agree with this assessment?**

A. No, I do not. By utilizing the Williamston Transmission Meter Proving Station Site to construct a Gas Sampling Station, the Company would realize immediate savings in labor resources, travel, and fleet expenses. Currently the Company employs a third-party natural gas analysis lab, located in Traverse City, to perform monthly and annual gas analysis. The Company's Operations employees travel more than 400 miles round-trip, often on a monthly basis. The cost of the gas analysis ranges from $150 to $200, or greater, per sample, depending on the type of analysis required. Gas Samples can range from 10-25 per month. The Company intends to leverage internal salaried employees, skilled and experienced, to perform the gas sample analysis at the Williamston Facility. The costs of

the third party performing the gas analysis would be eliminated as well as the significant costs for travel and fleet expenses. An ancillary value/benefit is the fact that this would reduce the turnaround-time between when a gas sample is taken and analyzed, enhancing gas quality best practices. Currently the Company bundles gas samples to attempt to create efficiencies and reduce travel.

**Q. On page 68, beginning on line 18, through page 69, line 1, of his direct testimony, Mr. Coppola discusses the $750,000 annual savings the Company would experience with the Williamston Transmission Meter Proving Station. Do you agree with his assessment?**

A. No, I do not. The $750,000 is not for the purchase of tools and equipment. The initial investment in tools and equipment is a one-time cost for the Company. As explained above, the third-party contractor incorporates the recurring costs of tools and equipment on each gas analysis building that they construct. The $750,000 savings would be realized by offsetting the Company's growing costs for constructing the gas analysis buildings out-of-state and leveraging the Williamston Transmission Meter Proving Station as a centralized location, where the Company or a third-party contractor can construct the gas analysis buildings. The current third-party out-of-state facilities are limited in the space they have to construct these gas analysis buildings. The Williamston Facility would have the necessary space, tools, equipment, and resources to realistically double the production output of current gas analysis buildings.

**Q. On page 69, beginning on line 1, through page 69, line 4, of his direct testimony, Mr. Coppola discusses the $108,000 annual savings the Company would experience with the Williamston Facility. Do you agree with his assessment?**

A. No, I do not. The estimated $108,000 annual savings would be realized by eliminating the Company's out-of-state travel/mileage/hotel expense costs for employees attending Factory Acceptance Testing at the third-party contractor's facility. Currently, the Company requires six representatives to attend the Factory Acceptance Testing to ensure quality control and perform safety, compliance, and functionality testing, for their particular disciplines. Factory Acceptance Testing is required twice, per gas analysis building, onsite at the contractor's facility, for the 50% completion and 100% completion of the gas analysis buildings. In addition to the actual travel/mileage/hotel expenses, there are associated costs during travel for the hourly employees required to attend and perform inspections. The Williamston Facility will be an average of 1.5 hours away from the majority of the Company's employees. This would eliminate most of the travel/hotel expenses and significantly reduce mileage and time charged for travel.

**Q. Should the Commission approve the Company's projection for the Williamston Meter Proving Station facility?**

A. Yes. This station will allow a testing environment for gas transmission measurement technology to comply with API-1164, which requires any new protocol, application, or software proposed to be added to the Supervisory Control and Data Acquisition ("SCADA") network should be run in a test-bed or development environment to evaluate the potential for impairing the performance of the SCADA system. Not only are the costs of the project reasonable, but I have described above the efficiencies gained with the

project. As shown on Exhibit AG-18, the annual projected efficiency from this project will be over $1,000,000. The Commission should reject Mr. Coppola's proposed reduction.

**Q. On page 69, beginning on line 8, through page 69, line 20, of his direct testimony, Mr. Coppola proposes that the Commission disallow the expenditures for project GM-00041 Rose Center Meter Replacement in the Deliverability Base Field Measurement Program based upon his review. Do you agree with this assessment and reason?**

A. No, I do not. The reasons for this project include the fact that the asset is at the end of its useful life. The operational deficiencies from the current meter are all described in Exhibit AG-18 (discovery response U21806-AG-CE-322_ATT_1). As seen in Exhibit AG-18, not proactively addressing the age of the measurement asset could impact over/under odorization and inaccuracies in volume measurement (gains or losses in Lost and Unaccounted for calculations for the site) due to inability to change the orifice plate. Mr. Coppola's recommendation should be rejected by the Commission and the Company's projection for this project should be approved by the Commission.

**Q. On page 42, beginning on line 5, through page 43, line 2, of his direct testimony, Mr. Coppola proposes reductions to six Deliverability Base Field Measurement Program projects based upon the status of the projects as of early March 2025. Do you agree with this assessment and reason?**

A. No, I do not. Each of these projects are progressing and have undertaken activities commensurate with projects that will be constructed in 2026. These are projects that are being actively worked on including site evaluation and other pre-engineering activities. Pre-engineering work would include survey work, SAP order creation, design

commencement, environmental reviews, real estate evaluation, scoping, and long lead-time material ordering. Company engineering sources utilize a prudent cadence prior to construction. The Company continues its normal cadence with these projects. Mr. Coppola's recommendation to remove project costs based upon the status should be rejected by the Commission and the Company's projection for these six projects in the Deliverability Base Field Measurement program should be approved by the Commission.

**Q. Beginning on page 70, line 11, through page 70, line 13, of his direct testimony, Mr. Coppola states that the Commission should remove $3,647,000 for the 10 months ending October 2025, and $17,559,000 for the projected test year from the Company's forecasted capital expenditures for the Deliverability Base Field Measurement Program. Do you agree with this recommendation?**

A. No, I do not. I have described above the reasons for each of Mr. Coppola's proposed reductions. The Company's full projection for this program should be approved by the Commission.

**Q. Beginning on page 70 of his direct testimony, Mr. Coppola discusses his review of the Deliverability Base Pipeline Program. On page 71, lines 5 through 12, he discusses a change to the Company's projects that the Company acknowledged in a discovery response and concludes that there should be a substantial reduction to rate base due to the insufficient information he purports to lack. Do you agree with this assessment?**

A. No, I do not. The Company acknowledged in Exhibit AG-19 (discovery response U21806-AG-CE-0333) that the 2025 project, B-GL-00251, had been cancelled and replaced by project GL-03313, a project originally planned for 2026. In that same response, the

Company provided sufficient information pertaining to a project that will be done in place of GL-03313 in 2026. This project, B-GL-00274, is an emergent inoperable valve project that will take place in 2026. The information provided in Exhibit AG-19 included the project phase, reason, and cost. This is the same information that had been provided for all other projects on my original workpaper, WP-MPG-4 (Exhibit AG-19), except for the project location, Ray, Michigan. I have included Exhibit A-12 (MPG-12), Schedule B-5.5 Revised and Exhibit A-61 (MPG-5) Revised to reflect the reductions to rate base for the changes described above.

**Q. Beginning on page 71, line 13 of his direct testimony, Mr. Coppola proposes reductions to eleven Deliverability Base Pipeline Program projects based upon the status of the projects as of early March 2025. Do you agree with this assessment and reason?**

A. No, I do not. Each of these projects are progressing and have undertaken activities commensurate with projects that will be constructed in 2026. Company engineers primarily manage projects being constructed in the current year up until late spring when these projects start to be released for construction. They then begin to work on projects for the next year which would include pre-engineering work such as SAP order creation, design commencement, environmental reviews, and long lead-time material ordering. Then they meet with gas control on when the projects can be done based on all other project work and system demands which determines the final scheduling of construction. Thus, Company engineering sources utilize a prudent cadence prior to construction. The Company continues its normal cadence with these projects. These projects support maintaining operations in accordance with the Michigan Gas Safety Standards ("MGSS").

Mr. Coppola's recommendation that these projects are too premature to include in rate base should be rejected by the Commission and the Company's projection for the Deliverability Base Pipeline Program shown on Exhibit A-61 (MPG-5) Revised should be approved by the Commission.

**Q. On page 72, line 6, through page 74 line 3, of his direct testimony, Mr. Coppola proposes reductions to city gate projects based upon an analysis of the historical average cost of projects in this program. Do you agree with this assessment and reductions?**

A. No, I do not. As shown in Mr. Coppola's analysis (Exhibit AG-20, page 6) there is a wide variation in the cost (and scope) of city gate modernization projects. This is because no two city gates are exactly alike, and the work required to modernize a city gate can vary widely. The cost for major rebuild projects during the 2022-2026 time frame range from $3,306,450 for GM-00914 (OVS Dorr CG Rbld) to $13,591,760 for GM-00943 (STC-Orion CG Rbld). It is also worth noting that many of the projects are very small in scope and though they do result in a modernized city gate, these projects do not compare to the size and scope of the majority of the test year projects. For example, project B-GL-00308 only involved installing a remote terminal unit ("RTU") and an emergency shut-down valve ("ESD") and cost $1.3 million and project GM-01078 only involved an ESD and cost $1.2 million. These projects were included in the average project cost calculation conducted by Mr. Coppola which reduces the overall average cost.

**Q. What would cause such variability in the cost of these projects?**

A. Below are some examples of the differences in scope and by extension cost of various city gate projects:

Small City Gate projects typically involve:

- Partial rebuild – some portion of the site is being rebuilt but not in its entirety;
- Small load – the flow at the city gate results in smaller piping and equipment; and
- Less equipment - may not contain an odorizer or single outlet.

Medium City Gate projects typically involve:

- Partial rebuild – some portion of the site is being rebuilt but not in its entirety;
- Less equipment - may not contain an odorizer or single outlet; and
- Full rebuild of a small to medium load facility.

Large City Gate projects typically involve:

- Full rebuild;
- Facilities that contain odorizers or multiple runs or large equipment;
- Large load – the flow at the city gate results in larger equipment and piping; and
- Includes additional measurement or valving requirements.

**Q. Can you provide some examples from Exhibit AG-20, page 6, of projects with varying costs and the equipment installed?**

A. Yes, I can. Below are some examples of projects of various sizes and the equipment replaced demonstrating the cost discrepancies in these projects.

Dorr City Gate – Small - $3.3 million:

- Small load with single medium pressure outlet and partial rebuild; and
- Scope included replacement of heater, odorizer, RTU, partial regulation replacement with trip out added and necessary piping; new filter separator. Equipment in the 2" and 4" sizing done for modernization needs. Building was not replaced, minimal site work.

Napoleon-Brooklyn City Gate – Medium –$6.5 million:

- 4" inlet 6" outlet full rebuild, includes medium sized odorizer and equipment; and
- Regulation with ESD, filter separator, heater, odorizer, electrical modernization, building, heater fuel meter, gas chromatograph cabinet, no additional transmission valving needs.

Bancroft City Gate – Large - $11 million:

- Full rebuild 6" inlet and 10" outlet piping; includes odorizer, measurement, and valving; and
- Includes demolition, construction of multiple measurement runs, electrical modernization and yard lighting, heater, odorizer, filter separator, regulation, emergency slam shut devices, meters, Remote Control Valve ("RCV"), check valve installation around tap valves, site work in the form of building, driveway, foundations.

Kalamazoo M Ave City Gate – Large – $13 million:

- Full rebuild with 12" inlet piping, 4 outlets, 2 at 12", 8" and 16"; includes odorization, measurement; and
- Large equipment – heater, filter separator, odorizer, nine regulators, ESD, tie-in valve depth work, new building, driveway, fencing, electrical modernization, ultrasonic meters, hydrocarbon dew point and O2 analyzers, and utilizing a refurbished Gas Chromatograph building.

**Q. On page 74, lines 1 through 3, of his direct testimony, Mr. Coppola recommends that the Commission remove $11,074,000 for the 10 months ending October 2025 and $14,408,000 for the projected test year from the city gate program projection. Do you agree with this recommendation?**

A. No, I do not. Mr. Coppola's analysis fails to take into account the varying costs of city gate projects. Each project was projected based upon the scope, size, equipment, and other factors described above. The Commission should reject the removal of the dollars proposed by Mr. Coppola for the city gate program.

**Q. On page 73, lines 9 through 12, of his direct testimony, Mr. Coppola discusses project status for the 2025 and 2026 projects and says, "it is very likely that the cost for these projects will change and could slip into a future year". Do you agree with this assessment?**

A. No, I do not. Mr. Coppola provides no evidence that this could or will likely happen. The status of these projects is in line with the normal cadence for projects in this program. At the time of this discovery response, the 2025 projects were in engineering design as they cannot be constructed until after the heating and storage field injection seasons are completed so that outages can be taken on the pipelines.

**Q. Beginning on page 74, line 4, through page 75, line 7, of his direct testimony, Mr. Coppola proposes a reduction to the TED-I Program for seven RCV projects based upon the status of the certain projects as of early March 2025. Do you agree with this assessment and reasoning?**

A. No, I do not. The RCV projects Mr. Coppola describes are in the normal phase for RCV projects that will be constructed the following year. The project process for RCVs is the following. The creation of the project scope documents, and potential surveying and material selection typically occur the year prior to construction (in 2025 in this case). The year of construction (2026) includes site survey work not completed in the prior year, the receipt of materials, the engineering and design work, release of design packages, contractor bidding and selection, and finally construction and project closeout. These seven projects are following the normal cadence for RCV projects and are thus not premature to be included in rate base. Mr. Coppola's proposed reduction to the RCV program should be rejected by the Commission.

**Q. On page 171, beginning on line 15, through page 172, line 11, of his direct testimony, Mr. Coppola proposes reductions to the Company's MAOP Transmission O&M related to the Standardized Engineering Analysis expenses. Do you agree with this assessment and reasoning?**

A. No, I do not. These expenses are a direct result of the Pipeline Safety, Regulatory Certainty, and Job Creation Act of 2011 and subsequent 2019 Safety of Gas Transmission Rules issued by the Pipeline and Hazardous Materials Safety Administration ("PHSMA") as described in my direct testimony beginning on page 24, line 21, through page 25, line 22. In MPSC Case No. U-21291, the case cited by Mr. Coppola, the Commission stated, "the 2019 revisions to federal pipeline safety regulations and the 2011 advisory bulletin are not new record keeping requirements and that DTE Gas was previously required by MGSS to perform strength tests, including MAOP tests, and to maintain those records for the life of the pipeline." The Company concurs that the Commission's second statement from this quote is correct; pipeline operators have been required to perform strength tests and keep those records for the life of facility since 1970 when subpart J pressure testing standards were implemented per 49 CFR § 192.517. Regarding the first statement, the Company maintains that the traceable, verifiable, and complete standard that PHMSA implemented in 2019 is an additional threshold beyond the recording requirements described in 49 CFR § 192.517. PHSMA deemed these original standards as not sufficient enough to prevent the recent incidents cited in the regulation; per the 2019 pre-amble, PHMSA states, "the purpose of this final rule is to increase the level of safety associated with the transportation of gas." Per the FAQ-30[1] provided in the Batch 1 FAQs, PHSMA details what it deems as

[1] https://www.phmsa.dot.gov/sites/phmsa.dot.gov/files/2023-05/Batch-1-FAQs-PHMSA-2019-0225-9-15-20.pdf

a TVC record; there are additional requirements that are not included in 49 CFR § 192.517. As an example of this higher standard, pressure test records are now required to be verifiable, which PHMSA states that they are "confirmed by the purchase order or project specification for the pipeline or the alignment sheet with consistent information." The study is appropriate so the Company can prove that its records now meet the TVC threshold in order to be compliant, which was directed by PHMSA in the 2011 bulletin that states "An operator must diligently search, review and scrutinize documents and records". All of the supporting evidence points to the conclusion that PHMSA intended to increase thresholds for records and require operators to evaluate said records in the name of safety. Therefore, the Company disagrees with Mr. Coppola's proposed 50% reductions.

**Q. Is the Company following the guidance from the MPSC Staff in its accounting treatment of these expenses.**

A. Yes. This is described in my direct testimony beginning on page 29, line 1, through page 30, line 1.

**Q. On page 172, beginning on line 12, through page 173, line 18, of his direct testimony, Mr. Coppola proposes reductions to the Company's Corrosion Control Transmission O&M expenses. In his review, he states that the expense for the test year is not supported by any increased work units or activities. Do you agree with this assessment?**

A. No, I do not. The discovery requests Mr. Coppola refers to in his direct testimony and are shown in Exhibit A-59 (MPG-3) were responsive to the information he requested. As shown in the response to discovery request U21806-AG-CE-338, the Attorney General did not ask for work units or activities. Further, in discovery request U21806-AG-CE-760, the

request was to explain what work was being done and not to provide work units or activities.

**Q. Were intervenors in this case provided the work units and associated costs in discovery?**

A. Yes, they were. Discovery request U21806-CUB-CE-0248, which was sent to all parties to this case provided the number of projects and average cost for each category in this program. Exhibit A-137 (MPG-10) includes the response to discovery request U21806-CUB-CE-0248. The difficulty with projecting work based on units in this program is the variability in the work. Specifically, for atmospheric corrosion projects, a project can be one item at a compressor station, or an entire city gate. The amount of work and resulting cost can be significantly different. Similarly, for recoat projects, the diameter of the pipe as well as length of the project are both variables that are difficult to anticipate and significantly affect the cost. These projected costs will ensure that sufficient funds are available for the Company to complete required work, including those mandated in recent rulemaking, in the required timeframes. Mr. Coppola's reduction to the Company projection in this program should be rejected by the Commission.

**Q. On page 195 of his direct testimony, Mr. Coppola states that there is no reason for the Commission to approve the Company's proposal to capitalize hydrotesting of pipelines in certain circumstances. Do you agree with this assessment?**

A. No, I do not. The Federal Energy Regulatory Commission has provided accounting guidance and the specific situations where the Company would utilize this accounting treatment is spelled out in Company witness Heather L. Rayl's direct testimony beginning on page 24, lines 1 through 16. In order to be able to capitalize these projects, the Company

needs to get approval from the Commission. Waiting for a project and then seeking approval is not practical. The Commission should reject Mr. Coppola's proposal.

## II. CUB WITNESS VEERAPANENI

**Q. Beginning on page 9 of his direct testimony, CUB witness Veerapaneni proposes a reduction to the Asset Relocation – Transmission Program expenditures in the test year. Do you agree with his proposal?**

A. No, I do not. The Company provided justification for the expenditures in the program through my direct testimony beginning on page 5, line 5, through page 9, line 20. My direct testimony describes the necessity of the expenditures and lists the projects to be conducted. Each project through the test year, the project reason, location, pipe length and approximate construction time frame are further shown in workpaper WP-MPG-1 (Exhibit AG-17). Mr. Veerapaneni simply took the average of the 2023 and 2024 actual expenditures and applied inflation to project a test year amount. The Company's projections are based upon knowledge of specific projects planned for the next several years. Annual projects and program costs vary depending upon customer requests for modifications, regulations, system condition, scope of projects, specific projects, and outage planning. Mr. Veerapaneni did not review the reasonableness of the projects proposed during the test year nor the benefits the projects would provide to customers. This methodology should be rejected by the Commission and the Company's projection should be approved.

**Q. Beginning on page 10 of his direct testimony, CUB witness Veerapaneni proposes an increase to the Regulatory Compliance Program expenditures in the test year. Do you agree with his proposal?**

A. No, I do not. The Company provided extensive documentation for the expenditures in this program and the sub-programs throughout my direct testimony, beginning on page 10, line 1, through page 30, line 1. These sub-programs are Pipeline Integrity Transmission, Pipeline Integrity TOD, Cathodic Compression, Storage and Pipeline, and MAOP Compliance Pipeline. My direct testimony describes the necessity of the expenditures and the regulations for which these expenditures allow the Company to comply. Mr. Veerapaneni simply took the average of the 2023 and 2024 actual expenditures and applied inflation to project a test year amount. The Company's projections are based upon knowledge of specific projects planned for the next several years. Annual projects and expenditures vary depending upon regulations, system condition, scope of projects, specific projects, and outage planning. Mr. Veerapaneni did not review the reasonableness of the projects proposed during the test year nor the benefits the projects would provide customers. This methodology should be rejected by the Commission and the Company's projection should be approved.

**Q. Beginning on page 12 of his direct testimony, CUB witness Veerapaneni proposes an increase to the Capacity/Deliverability Program expenditures in the test year. Do you agree with his proposal?**

A. No, I do not. The Company provided extensive documentation for the expenditures in this program and the many sub-programs throughout my direct testimony beginning on page 30, line 8, through page 48, line 20. These programs include TED-I, Deliverability

Base Field Measurement, Deliverability Base Pipeline, Regulator Stations – Distribution, and T&S City Gates. My direct testimony describes the necessity of the expenditures, lists the projects to be conducted and provides the expenditures. These projections are based upon knowledge of specific projects planned for the next several years. Further, capacity requirements can increase due to changes in customer population density in specific locations and also because of changes in system requirements.

Annual projects vary depending upon regulations, system condition, scope of projects, specific projects, and outage planning. The Company believes that the methodology used by CUB is unreasonable. Mr. Veerapaneni did not review the reasonableness of the projects proposed during the test year or the benefits the projects would provide to customers. This methodology should be rejected by the Commission.

**Q. On page 17 of his direct testimony, CUB witness Veerapaneni proposes a reduction to the Gas Regulatory Compliance Program O&M expenses in the test year. Do you agree with his proposal?**

A. No, I do not. As with the programs mentioned above, I provided a description of the necessity for the expenses in this program in my direct testimony beginning on page 10, line 1, through page 30, line 1. Mr. Veerapaneni simply took the average of the 2023 and 2024 actual amounts and applied inflation to project a test year amount. My direct testimony describes the necessity of the expenses and the regulations for which these expenditures allow the Company to comply. Mr. Veerapaneni did not review the reasonableness of the projects proposed during the test year or the benefits the projects would provide to customers. This methodology should be rejected by the Commission.

## III. MEC WITNESS DELEON

**Q. On page 30, line 9 of her direct testimony, MEC witness deLeon suggests that all utility programs should be assessed for risk reduction and cost effectiveness. Is it practical for every program to utilize a risk model and cost-effectiveness calculation?**

A. No, it is not. For Transmission programs and projects, some projects are customer requested, and a large number are in response to regulatory requirements or to maintain the reliability and resiliency of the Company's system. Thus, not all programs have projects that are as a result of a risk model. Pipeline Integrity and Asset Relocation Transmission programs utilize data from the model to prioritize projects. But a significant portion of the other transmission programs' projects are otherwise indicated. For example, Corrosion Control projects allow the Company to maintain compliance with federal regulations for cathodic protection of facilities. MAOP Compliance Pipeline projects involve MAOP verification and remediation of the Company's transmission pipelines. Most TED-I projects going forward concern the installation of RCVs to improve public safety and minimize gas flows after a failure. The Deliverability Base Field Measurement Program is essential to ensure accurate gas quality and measurement. The Deliverability Base Pipeline Program supports maintaining operations in accordance with the MGSS. City gate investments allow for the rebuilding or other improvements to existing city gate facilities to ensure system reliability and in response to increased customer load demands. Regulator station investments are distribution assets but aimed at maintaining the integrity of 648 regulator station on the Company system.

**Q. Beginning on page 41, lines 1 through 5 of her direct testimony, MEC witness deLeon makes recommendations concerning investment levels in future rate case applications. Do you agree with this recommendation?**

A. No, I do not. Dr. deLeon seems to be indicating that the Company be frozen at the 2024 level for capital investment amounts regardless of the historical test year or other changes in regulations in future rate case filings. This recommendation is unreasonable. The Company's forward looking rate case filings contain projects and programs supported by expert witness testimony which describe the necessity of the expenditures based upon system conditions, safety improvements and compliance with regulations. This recommendation should be rejected by the Commission.

**Q. Does this conclude your rebuttal testimony?**

A. Yes, it does.

MR. RUSZKIEWICZ: The Company's next witness is Kendra K. Grob. Based on stipulation of the parties, the Company moves to bind in the testimony of Kendra K. Grob. Her direct testimony consisted of a cover page, plus 37 pages of prefiled testimony. She also had rebuttal testimony in the form of a cover page and 5 pages of rebuttal testimony.

The Company also moves to admit Ms. Grob's exhibits, which consist of Exhibit A-64, A-65, A-66, and a confidentially filed A-67. That's it. Thank you.

JUDGE VARCHETTI: All right. Are there any objections to the binding in of Ms. Grob's direct and rebuttal testimony or any of her associated exhibits?

Hearing none, the testimony is bound into the record and the exhibits are admitted.

MR. RUSZKIEWICZ: Thank you.

(Direct and Rebuttal Testimony bound in)

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

| | | |
|---|---|---|
| In the matter of the application of<br>**CONSUMERS ENERGY COMPANY**<br>for authority to increase its rates for the<br>distribution of natural gas and for other relief. | )<br>)<br>)<br>)<br>) | Case No. U-21806 |

**DIRECT TESTIMONY**

**OF**

**KENDRA K. GROB**

**ON BEHALF OF**

**CONSUMERS ENERGY COMPANY**

December 2024

**Q. Please state your name and business address.**

A. My name is Kendra K. Grob, and my business address is One Energy Plaza, Jackson, Michigan 49201.

**Q. By whom are you employed?**

A. I am employed by Consumers Energy Company ("Consumers Energy" or the "Company").

**Q. What is your current position with Consumers Energy?**

A. I am currently the Senior Manager, Benefits.

**Q. What are your responsibilities as Senior Manager, Benefits?**

A. I am responsible for design, implementation, and administration of the Company's retirement and health care plans and our department has responsibility for the benefit plans for employees and retirees. In the retirement benefits area, the Company contributes to the cost of the Pension Plans, the Defined Company Contribution Plan ("DCCP"), and the 401(k) Employees' Savings Plan ("ESP"). My responsibilities for these benefit plans include the design, review, and administration of competitive, cost-effective, quality plans that will attract and retain qualified employees to serve customers. The purpose of these plans is to provide a portion of an employee's retirement income along with the employee's social security benefits and personal savings.

In the benefits area, the Company contributes to the cost of these benefits plans – health care (medical/prescription drug/dental including Health Savings Accounts ("HSAs") and Health Care Flexible Spending Accounts ("HCFSAs"), life insurance, and Long-Term Disability ("LTD") insurance. Like the retirement plans, our department also has responsibilities for these health care and other benefit plans to include the design, review, and administration of competitive, cost-effective, quality plans for employees and retirees

of the Company that help attract and retain qualified employees to serve customers. In addition to these plans, the Company has the responsibility for several additional benefit plans offered to employees by the Company at group discounted rates, which require the employee to pay the full cost of the coverage elected. These voluntary plans include accidental death and dismemberment insurance, health care and dependent care flexible spending accounts, vision insurance, and dependent term life insurance. In 2024, the Company added hospital indemnity, critical illness, and accident benefits. These insurance benefit plans help attract and retain qualified employees to serve customers as these plans help protect employees and their families from significant financial loss in a number of areas. Our team is also responsible for Absence Management, Workers' Compensation, and Occupational Health programs, as well as the total well-being program, Live Well 365, which motivates employees to manage their entire well-being.

**Q. What is your formal educational experience?**

A. In 1998, I graduated from Siena Heights University in Adrian, MI with a Bachelor of Business Administration degree. I hold a Professional certification in Human Resources from HR Certificate Institute ("HRCI") and the Society of Human Resource Management ("SHRM").

**Q. Would you please describe your previous work experience?**

A. In 1995, I began my career focused on human resources at Health Care Solutions, Inc. as a Human Resources Manager. In this role, I was responsible for the Human Resource Management of the corporate office in Ann Arbor, MI. Also, I had leadership responsibility over all field Human Resource Managers. In addition to this responsibility, I managed all health care and retirement plans for the company. It was my sole

responsibility to ensure employees were enrolled in the correct plans and provide any administration to the plan. This also included plan audits and decision making in determining the best vendors.

In 2007, I began working for Amcor Rigid Packaging as a Senior Benefits Specialist. My area of responsibility was retirement plans, disability, and life insurance plans. In this role, I was responsible for the relationship with vendors and the administration of plans for our employees. I was the primary vendor contact for these areas and was heavily involved in all Request for Proposal processes in choosing vendors. While in this position, I sat on the Retirement Committee as the Secretary and took part in plan design and fund selections for both the pension and the savings plan.

In 2020, I joined Consumers Energy as Manager, Retirement Plans. My responsibilities included complete oversight for the Company pension and savings plans (401k). In this role, I ensured the Company provides retirement benefits to active and retired employees while maintaining accurate legal compliance with the Internal Revenue Service.

In March 2024, I was promoted to Senior Manager, Benefits. In this role I continued complete oversight for the Company pension and savings plans (401k) with the addition of assuming responsibility for health and welfare benefits.

**Q. Are you a member of any professional societies or trade associations?**

A. I am professionally certified as a Human Resources Professional through both SHRM and HRCI.

**Q. What is the purpose of your direct testimony?**

A. The purpose of my direct testimony is to provide support for the Company's costs related to the gas business portion of retirement, health care, life insurance, LTD plans, and other benefits provided to its employees and retirees. In Part I of my direct testimony, I will address the retirement benefits plans. In Part II of my direct testimony, I will address health care, life insurance, LTD plans, and other benefits, which include absence management and educational assistance programs.

**Q. Are you sponsoring any exhibits?**

A. Yes, I am sponsoring the following exhibits:

| | |
|---|---|
| Exhibit A-64 (KKG-1) | Summary of Actual and Projected Benefits O&M Expenses for the Year 2023 and Test Year Twelve Months Ending October 31, 2026; |
| Exhibit A-65 (KKG-2) | CMS Energy – Pension Plans A and B - ASC 715 Pension Expense Estimates ($ millions); |
| Exhibit A-66 (KKG-3) | CMS Energy - ASC 715 OPEB Expense Estimates ($ millions); and |
| Confidential Exhibit A-67 (KKG-4) | CMS Energy – Actuarial Letter of Support for 2024 Year Projections. |

**Q. Were these exhibits prepared by you or under your supervision?**

A. Yes.

**Q. Please describe Exhibit A-64 (KKG-1).**

A. Exhibit A-64 (KKG-1), page 1, summarizes 2023 actual expenses through the 12 months ending October 31, 2026, projected gas Operating and Maintenance ("O&M") expenses for the Company's retirement and insurance benefit plans offered to employees and retirees. On this exhibit, column (a) provides a program description of the O&M expense

category. Column (b) provides the actual expense in 2023 for each plan. Column (c) provides the projected expense for the 12 months ending October 31, 2026. Page 2 provides information on inflation factor projections and adjustments using the methods discussed in this testimony and included in column (i). Column (j) is the projected test year O&M expense and is the sum of columns (b) + (d) + (f) + (h) + (i).

**Q. Please describe Exhibits A-65 (KKG-2) and A-66 (KKG-3) and Confidential Exhibit A-67 (KKG-4).**

A. Exhibits A-65 (KKG-2) and A-66 (KKG-3) provide the Aon actuarial projections for Pension and Other Post Employment Benefit ("OPEB") expenses for the years identified. Both the Pension and OPEB projections in these exhibits provided by the Aon actuaries are from the year-end 2023 measurement of the Pension and OPEB plans and with current market conditions as of December 31, 2023. A letter from the actuary regarding the accuracy and completeness of the projections is included in Confidential Exhibit A-67 (KKG-4).

## I. RETIREMENT BENEFITS PLANS

**Q. Which retirement benefits are you addressing in this section of your direct testimony?**

A. I am addressing the Pension Plans, DCCP, and ESP. These expenses are shown on Exhibit A-64 (KKG-1), page 1, lines 1 through 3.

**Q. How are the Pension Plans, DCCP, and ESP expenses that are common to electric and gas operations allocated to the gas portion of the business?**

A. Expenses common to both the electric and gas operations associated with the Pension Plans, DCCP, and ESP are allocated based on the relationship of employee labor dollars charged to gas operations compared to the labor dollars charged to both electric and gas

operations. These allocations are made by the Accounting Department. The gas portion of the O&M expense for these plans is shown on Exhibit A-64 (KKG-1), page 1.

**Pension Plans**

**Q. Would you please explain your Exhibit A-64 (KKG-1), line 1, which begins with ($28,482,000) in 2023?**

A. Exhibit A-64 (KKG-1), page 1, line 1, shows the actual 2023 pension expense and the projected expense for 12 months ending October 31, 2026, attributable to the gas portion of the utility operations.

**Q. How does the Company determine its expense for the Pension Plans?**

A. The pension expense is determined using actuarial analysis that is performed in accordance with Accounting Standards Codification ("ASC") 715. Consumers Energy follows Generally Accepted Accounting Principles ("GAAP") for its financial statements. Under the provisions of GAAP, ASC 715 describes the methodology and assumptions required to properly calculate and account for pension expense which includes evaluation of market conditions at each of the Pension Plan's measurement dates. In addition, the Company's auditor rigorously reviews the process to ensure compliance with GAAP and ASC 715.

ASC 715 requires an annual determination of pension expense. Pension expense is determined based on actuarially reviewed employee census data, plan provisions, plan assets, and certain other assumptions. Year-end disclosure information is also produced, based on these accounting standards, to show a reconciliation of plan assets and liabilities at the end of the Company's fiscal year. For this gas rate case, the Pension Plans were measured in January for year-end December 31, 2023.

**Q. What are the components of the annual pension expense under ASC 715?**

A. There are four components of the annual pension expense: (i) service cost; (ii) interest cost; (iii) expected return on plan assets; and (iv) amortization of gains or losses, prior service costs or credits, and any transitional amounts. The plan's service cost represents the value of the benefits earned during the year. This is determined individually for each participant based on their specific employee demographics. The interest cost represents interest on the plan's liabilities due to the passage of time. There is also an assumption made for the expected return on plan assets. The expected return on plan assets each year reduces the plan's annual expense. The expected return assumption is reviewed periodically by the plan's actuary, the plan's investment advisor, and the Company, and is intended to be a long-term assumption based on the best estimate of the long-term expected investment earnings of the plan assets. The last component of plan expense is amortization of various plan experiences that were not anticipated by the plan's actuarial assumptions. For example, plan experience gains or losses and plan design changes that would be amortized are included as a part of this component of plan expense. The amortization can be either credits or costs.

To calculate the plan's total pension benefit obligation and annual ASC 715 expense, the actuary uses a number of assumptions including discount rate, mortality table, salary change, expected return on plan assets, and expected future contributions needed to avoid benefit restrictions under the Pension Protection Act. The methods used to set assumptions are generally unchanged annually, while the values of each assumption are determined by the Company each year and reviewed by the Company's auditors and actuary.

**Q. Please describe how the discount rate is set each year.**

A. The Company relies on its actuary's discount rate setting model. The model uses current high-quality bonds to match the Pension Plan's cash flows using statistical techniques that create a yield curve that determines the effective discount rate for all maturities of pension payments. The model itself does not change annually, but the discount rate typically will be updated based on the most current market conditions.

**Q. Please describe how the expected return on plan assets is set each year.**

A. The Company uses future expected capital market assumptions, asset allocation information, and other resources provided by its consultants, which may include survey data and analysis of the Pension Plan's asset allocation. The expected return assumption is based on long-term expectations and not short-term returns. The Company uses all this information to establish an expected return on plan assets assumption that best estimates its expectation. While this assumption is reviewed for each plan measurement, it may or may not be updated annually depending on the information that is presented.

**Q. Does the Company apply Accounting Standard Update ("ASU") No. 2017-07 Improving the Presentation of Net Periodic Pension/OPEB Costs Standard in this case?**

A. Yes, the Company adopted the ASU No. 2017-07 standard as of January 1, 2017, and has applied the Standard in this case for both Pension and OPEB. This ASU No. 2017-07 standard allows only the service cost component of expense to be recorded as an operating expense and all other benefit-cost components are to be recorded outside operating income. The Standard also allows only service costs to be capitalized, while all other cost components are recorded to net income immediately.

**Q. Please describe the development of the Pension Plans' expense shown on Exhibit A-64 (KKG-1), page 1, line 1, which begins with ($28,482,000) for 2023.**

A. The annual pension expense shown on Exhibit A-64 (KKG-1), page 1, line 1, for the gas utility is based upon Aon's actuarial determination of each plan's total expense for that year in accordance with ASC 715 and includes plan administration fees, aggregated for total pension expense. The Consumers Energy pension expense determined by Aon plus administration fees are allocated to the electric and gas portions of the utility using the Accounting Department methodology described earlier. This allocation resulted in the actual gas utility O&M expense for Pension of ($28,482,000) in 2023, and projected expense of ($34,801,000) for the 12 months ending October 31, 2026. Exhibit A-64 (KKG-1), page 2, line 1, column (i), compares the Aon actual calculation of expense with the 2023 actual expense, as adjusted for 2024, 2025, and 2026 inflation, to calculate other adjustments.

**Q. Have there been any significant changes to the Pension Plan structure in recent years?**

A. Yes. The Company split its Pension Plan into two plans as of January 1, 2018. Generally, all participants who were employees of the Company on August 1, 2017, were included in Pension Plan A. All other participants, including any Cash Balance participants, were assigned to Pension Plan B. No changes to participant benefits occurred because of this change. The Company decided to make this change to help manage expenses of the Pension Plans by extending the amortization period for the inactive group and enabling the mitigation of Pension Benefit Guarantee Corporation premium variability.

**Q. Did the Company make any cash contributions to the Pension Plans in 2023?**

A. No, the Company did not contribute to either plan in 2023.

**Q. Will the Company make any cash contributions to the Pension Plans in 2024?**

A. No cash Pension Plan contributions are required in 2024 to avoid benefit restrictions. Any contributions the Company elects to make during these periods of time will depend upon future decisions of the Company regarding funding policy, the future value of plan assets and liabilities, and any potential legislative guidance or changes.

**Q. Why did the pension expense decrease for the projected test year from 2023?**

A. The Pension expense decreased due to higher-than-expected asset returns in 2023.

**Q. Have any changes recently been made to the Pension Plans' benefits?**

A. No significant benefit changes have been made to the Pension Plans since September 1, 2005, when the Pension Plans were closed to new hires and the DCCP was implemented for new hires. Increases in pension expense created by the assumption changes are moderated by the closure of the Pension Plans to new hires as of September 1, 2005. In addition, pension liabilities and expenses are moderating overall as many participants are retiring or leaving and commencing their benefits, which reduces the liability and associated expense over time. Liability and expense will continue to diminish (presuming no significant change in the market or discount rates) until there are no longer any employees or retirees covered by the defined benefit ("DB") Pension Plans.

Effective November 1, 2020, the Company changed the unreduced early retirement age from 62 to 61 for the Company's pension union eligible employees. This benefit enhancement allows for the Company to continue to retain current union pension eligible employees since they can now retire one year earlier but not lose any percentage of their pension benefit and was very well received. The additional changes in the projected pension expense estimates from 2023 to the 12 months ending October 31, 2026, are

primarily the result of economic conditions external to the Pension Plans over which the Company has no control.

**DB Pension/OPEB Volatility Mechanism ("VM")**

**Q. Please describe the DB Pension/OPEB VM that the Company is proposing.**

A. The Company requests the ability to continue its implementation of a DB Pension/OPEB VM that the Company was authorized to implement in the Commission's settlement agreement in Case Nos. U-21490 and U-21308. The sensitivity of DB Pension/OPEB expenses to changes in asset returns or other assumptions creates a significant potential for large variability in future expenses. Customers benefit from a mechanism that eliminates the risk of future volatility in expense. Without a mechanism, there could be substantial, unanticipated swings in the DB Pension/OPEB expense. The proposed mechanism, which mirrors the mechanism that has existed since October 2023, would protect customers from this volatility by allowing the Company to defer annually the difference between the DB Pension/OPEB expense included in rates versus the actual annual DB Pension/OPEB expense recorded by the Company pursuant to ASC 715.

**Q. Is the mechanism symmetrical?**

Yes. Under the mechanism, if the actual annual DB Pension/OPEB expense is less than the expense approved in rates, the difference would be recognized as a regulatory liability and amortized over 10 years starting the following January. Similarly, if actual annual DB Pension/OPEB expense is greater than the expense approved in rates, the difference would be recognized as a regulatory asset and amortized in the same manner. Any amortization of these regulatory assets or liabilities would be included in future general rate cases. The mechanism is not only fair; similar mechanisms have been approved by the Commission

for other utilities in contested cases. See, e.g., MPSC Case No. U-20836, November 18, 2022 Order, pages 291-292; MPSC Case No. U-20940, December 9, 2021 Order, page 154.

**Q. Please describe the Pension VM Deferral on Exhibit A-64 (KKG-1), page 1, line 7, column "b", which begins with $(266,000) for 2023.**

A. Per the Settlement Agreement in Case No. U-21308, the Company was authorized to defer actual DB Pension expense different than the approved amount of ($29,547,000) starting October 1, 2023. In 2023, the DB Pension expense was higher than the approved 12-month amount as shown on Exhibit A-64 (KKG-1), page 1, line 1, column b, of ($28,482,000) for October 1, 2023 to December 31, 2023. The Company compared the three months of authorized $7,386,750, taking the 12-month authorized $29,547,000 dividing by 12 and times by three for the three months October 1, 2023 to December 31, 2023. The Company recorded the difference between the actual DB Pension expense and the approved rate expense for the Pension VM for that time period. The Pension VM of ($266,000) resulted in a decreased expense for 2023, and the Company consequently recorded a Pension VM regulatory asset for $266,000.

**Q. Please describe the Pension VM Amortization on Exhibit A-64 (KKG-1), page 1, line 9, column "c", which begins with ($791,000) for 12 months ending October 2026.**

A. The Pension VM amortization includes the deferred amounts being amortized for the years 2023 to 2025. The deferred Pension VM is being amortized over 10 years which is consistent with how the VM settlement in Case Nos. U-21490 and U-21308 will operate.

**Q. Please describe the OPEB VM Deferral on Exhibit A-64 (KKG-1), page 1, line 8, column "b", which begins with ($31,142,000) for 2023.**

A. Per the Settlement Agreement in Case No. U-21308, the Company was authorized to defer actual OPEB expense different than the approved amount of ($31,142,000) starting October 1, 2023. In 2023, the OPEB expense was lower than the approved 12-month amount as shown on Exhibit A-64 (KKG-1), page 1, line 5, column b, of ($33,761,000) for October 1, 2023 to December 31, 2023. The Company compared the three months of authorized $7,785,500 taking the 12-month authorized $31,142,000 dividing by 12 and times by three for the three months October 1, 2023 to December 31, 2023. The Company recorded the difference between actual OPEB expense and approved rate expense for the OPEB VM for that time period. The OPEB VM of $655,000 resulted in an increased expense for 2023, and the Company consequently recorded an OPEB VM regulatory liability for $655,000.

**Q. Please describe the OPEB VM Amortization on Exhibit A-64 (KKG-1), page 1, line 10, column "c", which begins with ($1,423,000) for 12 months ending October 2026?**

A. The OPEB VM amortization includes the deferred amounts being amortized for the years 2023 to 2025. The deferred OPEB VM is being amortized over 10 years which is consistent with how the VM settlement in Case Nos. U-21490 and U-21308 will operate.

**DCCP**

**Q. Does the Company provide an alternative qualified benefit plan to the closed Pension Plans for employees hired on and after September 1, 2005?**

A. Yes. In order to remain competitive by offering a benefits package that attracts and retains qualified and talented employees for the benefit of the customer, the Company replaced the Final Average Pay and Cash Balance versions of the qualified DB Pension Plan with the qualified DCCP for all existing Cash Balance participants and newly hired employees on and after September 1, 2005.

**Q. Are there any employees included in the DCCP that were hired before September 1, 2005?**

A. Yes. Those employees who were hired between July 1, 2003, and August 31, 2005, and were provided coverage under the Cash Balance version of the DB Pension Plan became participants in the DCCP as of September 1, 2005. At the same time, for this specific group of employees, additional pay credits under the Cash Balance version of the DB Pension Plan were discontinued.

**Q. Will the Cash Balance version of the DB Pension Plan accept any new employees as participants?**

A. No. As with the Final Average Pay DB Pension Plan, the Cash Balance version of the DB Pension Plan now has a finite group of participants that, over time, will diminish until there are no longer any employees or retirees covered under this plan.

**Q. Please provide a general description of the DCCP.**

A. The DCCP currently provides an employer funded cash contribution as a percentage of an employee's base pay to the ESP—the percentages vary with years of service as described

below. No employee contribution is required to receive the employer contribution. All existing Cash Balance Plan employee participants and employees hired on and after September 1, 2005, participate in the DCCP as part of their retirement benefit package.

**Q. Have any recent changes been made to the DCCP?**

A. No changes have been made to the DCCP since 2021. Effective January 2021, for the Company's union employees, the DCCP provides an 8% to 10% (previously 5% to 7%) employer funded cash contribution based upon the union employee's service time with the Company. New union hires receive an 8% contribution, which increases to 9% when they have six years of service with the Company. When union employees reach 12 years of service, they receive a 10% employer contribution. This service-based contribution approach for the DCCP serves as a talent retention mechanism. The increase in the union DCCP contributions was needed for the Company to remain competitive to attract qualified employees and retain talent that maximizes the efficiency of the Company's labor force and reduces costly turnover. Retaining trained, experienced, and motivated employees provides better service for customers.

The Company's exempt and non-exempt employees will continue to receive the DCCP which was effective in January 2016. The DCCP provides a 5% to 7% (previously 6%) employer funded cash contribution based upon the employee's service time with the Company. New hires receive a 5% contribution, which increases to 6% when they have six years of service with the Company. Employees receiving a 6% contribution before January 1, 2016, continue to receive their 6% employer contribution. When employees reach 12 years of service, they receive a 7% employer contribution. This service-based contribution approach for the DCCP serves as a talent retention mechanism and helps

contain the cost of the DCCP for the benefit of the customer as all new hires starting in 2016 began receiving a 5% (previously 6% for new hires) employer contribution.

**Q. Would you please explain your Exhibit A-64 (KKG-1), page 1, line 2, which begins with $7,952,000 in 2023?**

A. Exhibit A-64 (KKG-1), page 1, line 2, represents the gas operations O&M expense related to the DCCP. The actual gas operations expense for this plan in 2023 was $7,952,000 as shown in column (b). Column (c) shows the projected gas DCCP expense of $8,155,000 for the 12 months ending October 31, 2026. DCCP costs are projected to increase using inflation factors of 3.2% for 2024, 2.4% for 2025, and 2.5% for 2026. If a DB Pension individual retires, the new person hired to replace their role is entered into the DCCP plan. For the projected years 2024 thru the 12 months ending October 31, 2026, costs were split using 61% electric and 39% gas, with 61% capital on gas expenses.

**Q. As a result of the revised eligibility requirements for participation in the Final Average Pay DB Pension Plan or the Cash Balance version of the DB Pension Plan, is it correct to say that all new hire employees who started on September 1, 2005, and after will receive their retirement benefits through plans that are referred to as defined contribution type plans?**

A. Yes. The primary plans that will provide monetary benefits to this group of employees upon retirement are the DCCP and the ESP.

**ESP**

**Q. Please explain briefly the ESP.**

A. The ESP is a defined contribution retirement savings program funded by employee and employer contributions. A portion of employee contributions is matched by Consumers

Energy. Prior to January 2022, the Company matched 100% of the employee's first 3% in contributions and 50% of the employee's next 2% in contributions to the ESP. Employee contributions beyond 5% were not matched by the Company. Consumers Energy's expense includes the Company's matching contributions, and the payments made to Fidelity Investments for administration of the program.

**Q. Have any recent changes been made to the ESP?**

A. Effective in January 2022, the Company match design has changed only for Salaried (exempt and non-exempt) employees to 100% of employee contributions up to 6% of the employee's salary. Employee contributions beyond 6% will not be matched by the Company. This change will help to keep the ESP cost and talent retention competitive in the market for the benefit of customers. The Union employees will continue receiving matching contributions of 100% for employee contributions of up to 3% of the employee's salary, and then 50% of employee contributions up to the next 2% of the employee's salary.

**Q. Would you please explain your Exhibit A-64 (KKG-1), page 1, line 3, which begins with $6,449,000 in 2023?**

A. Exhibit A-64 (KKG-1), page 1, line 3, represents the Company's gas operations expense related to the ESP. In 2023, the actual gas utility O&M expense for the ESP was $6,449,000. The gas utility's ESP O&M expense projected for the test year is $6,615,000. Savings Plan costs are projected to increase using inflation factors of 3.2% for 2024, 2.4% for 2025, and 2.5% for 2026. For the projected years 2024 through the 12 months ending October 31, 2026, costs were split using 61% electric and 39% gas, with 61% capital on gas expenses.

**Q. Is the ESP employer matching program important to attracting and retaining employees?**

A. Yes.

**Q. Please explain why the ESP employer matching program is important to attract and retain employees.**

A. The ESP with a match is commonly available from Michigan employers as well as from other utility company employers that Consumers Energy competes with for employee talent. It is necessary to continue providing this highly visible, competitive benefit to employees of Consumers Energy to continue attracting and retaining competent employees needed by the Company, particularly considering the large number of retirement-eligible employees at the Company. Attracting qualified employees and retaining this talent maximizes the efficiency of the Company's labor force and reduces costly turnover. Safe, reliable, and affordable gas service begins and ends with the Company's people. Investing in and retaining trained, experienced, and motivated employees' benefits customers as much as, or more than, any investment in infrastructure.

**Q. Is the ESP employer match discretionary?**

A. It is not discretionary for union employees. A provision in the Working Agreement ratified in 2005 with Operating Maintenance & Construction ("OM&C") and Virtual Call Center ("VCC") union employees assured these employees that the match would not be suspended during their five-year contract. This provision was renewed in the 2010 contracts as part of the final union agreements for these union groups, and it is also part of the Steelworker's union contract effective January 1, 2011. This provision was not changed in the most recent five-year contracts negotiated in 2020. This has been a prominent issue for the union

during the last several labor negotiations, all of which were finally resolved through arms-length bargaining.

With respect to non-union employees, there is not a similar contractual prohibition against suspension. However, the ESP employer match is part of an overall competitive benefits package and employees depend upon its continuation so they can accumulate savings for retirement. The Company's competitors continue to offer a savings plan match, and the Company plans to continue offering the match to compete for new talent and retain current talent for the benefit of the customer. As noted above, it is a benefit that helps the Company attract and retain qualified and talented employees. From a practical standpoint, the Company views the employer match as non-discretionary.

## II. HEALTH CARE, LIFE INSURANCE, LTD PLANS, AND OTHER BENEFITS

**Q. Which health care and insurance benefits are you addressing?**

A. I am addressing active employee health care (including HSAs and HCFSAs), life insurance, LTD plans, and other benefits of absence management and educational assistance, as well as retiree health care and life insurance plans. These expenses are shown on Exhibit A-64 (KKG-1), page 1, lines 4 through 6.

**Q. Are the expenses for active employee health care (including HSAs and HCFSAs), life insurance, and LTD benefits determined in the same way as expenses for retiree health care and life insurance benefits?**

A. No. The expenses for active employees are based upon the actual costs for these benefits that are expected to be incurred. The expenses for retirees are determined using actuarial analysis, which is performed by the Company's actuary, in accordance with ASC 715, formerly known as Financial Accounting Standards ("FAS") 106.

**Q. How were the portions of active employee and retiree health care (including HSAs and HCFSAs), life insurance, LTD, and other benefits costs allocated to gas O&M expense determined?**

A. The portion of the Company's total program expenses attributable to the gas utility was allocated based upon an annual study by the Accounting Department of the relationship of the number of employees in the gas utility to the total number of employees in both the electric and gas utility. The amount allocated to the gas utility is allocated between O&M expense and capital expense based upon the Accounting Department's formula. For the projected years 2024 thru the 12 months ending October 31, 2026, costs were split using 55% electric and 45% gas, with 61% capital on gas expenses.

**Active Health Care (Including HSAs and HCFSAs), Life Insurance, LTD, and Other Benefits**

**Q. Please describe the development of the active health care (including HSAs and HCFSAs), life insurance, and LTD expense levels that are shown on Exhibit A-64 (KKG-1), page 1, line 4, which begins with $18,359,000.**

A. Exhibit A-64 (KKG-1), page 1, line 4, contains gas operations O&M expenses for the Company-funded benefit plans for active employees' health care (including HSAs and HCFSAs), life insurance, and LTD. The primary component of this expense is health care. Life insurance and LTD make up a much smaller portion of the expense. In 2023, the Company incurred an actual combined expense of $18,359,000 for health care, life insurance, and LTD for gas operations. The projected gas operation expense for these benefits for the projected test year is $19,765,000.

**Q. What factors did you consider when projecting the test year's expenses for health care, life insurance, and LTD?**

A. In projecting the test year's health care expenses, a number of factors were considered. The primary factors included current and projected inflation factors and a review of 2023 and 2024 national health trends/costs survey information provided by Willis Towers Watson ("WTW") actuarial consulting. Additional factors considered were the Company's medical and prescription drug carrier's health cost and claims experience expectations, the continuing rapid rise in availability and price of specialty prescription drugs, the current employee headcount, and the continuing cost increase impacts of national health care reform.

**Q. Please explain how these factors were used to determine the Company's expected health care costs.**

A. The Company has determined that using the inflation factors in this case will keep cost increases in line with inflation amounts. Exhibit A-64 (KKG-1), page 2, line 4, column (i), compares the projected test-year expense with the 2023 actual expense, adjusted for 2024, 2025, and 2026 inflation, to calculate other adjustments.

To further understand projected health care trends and costs, the Company and WTW reviewed expected health care trends and costs survey information from several large consulting firms. The Company and WTW also reviewed the Company's actual health care claims experience for employees and retirees in its health plans - Blue Cross/Blue Shield of Michigan ("BC/BS") and Express Scripts. This analysis of the Company's health plans revealed that the Company's workforce is older than the average age of the population insured by the BC/BS and Express Scripts plans, and as a result, the

Company's health plans have a higher expected utilization rate that is associated with an older covered population. Of the Company's current workforce, as of December 31, 2023, 49% of employees are over age 45; 34% are over age 50; and 20% are over age 55. The Company understands the older age of its workforce is expected to lead to a higher health care expense (primarily due to utilization of services).

To project future health care expenses, the Company and WTW also considered all the plan changes and programs that the Company has already implemented. These changes include sharing expected health care expense increases with employees through plan design changes like increased deductibles, copayments, and out-of-pocket maximums; increasing employee premium contributions for coverage; adding telehealth benefits to medical plans to lower expense; educating employees regarding the prudent and informed use of health care benefits; promoting use of preventive benefit services; promoting well-being through Live Well 365, which is integrated into all medical plan designs, that encourages and rewards plan participants for taking steps toward healthier lifestyles; securing favorable pricing on prescription drugs obtained through a large employer prescription drug collaborative; negotiating lower administrative fees with health plans and promoting enrollment into the Consumer Directed Health Plan ("CDHP"), a high deductible health plan which currently provides a Company contribution to the participant's HSA.

The Company and WTW also considered the specific changes to the union employees' health care plan benefits as negotiated in its 2020 through 2025 contracts, as well as changes made to the employees' health care benefit plans in 2021 described in detail later in this direct testimony. While there are very tangible savings in future health expenses to the Company and its customers as a result of these changes to employee health

care benefit plans, the Company believes a portion of these savings will be offset by increased health expenses incurred under national health care reform requirements (like Patient Centered Outcomes Research Institute fees, employer mandate shared responsibility administrative/reporting requirements, and potential penalties) as well as increased prescription expenses due to the availability of new and expensive specialty prescription drugs in the market. In addition, while the Company has taken numerous steps to control the rising expense of health care, many of these changes are one-time events that lower a plan's expense in that year to establish a new baseline moving forward, but future health care expenses then continue to increase from the new baseline expense.

**Q. What are some of the reasons that health care costs are increasing at a level higher than general inflation?**

A. There are a number of factors causing a higher rate of health care inflation than is reflected in the general Consumer Price Indexes ("CPIs"). Health care costs are expected to continue rising during the next several years due to an aging population living longer, additional utilization of services, price increases for services, new medical technology, cost shifts from government plans, mandated benefits coverage, rising provider malpractice premiums, new taxes on health claims, and rapidly escalating prescription drug prices including high prices for new, expensive specialty drugs. In addition, national health care reform will increase Company health care costs in the near term because of eligibility expansions (e.g. adult children to age 26), mandated benefits, removal of annual dollar limits, additional taxes, fees, penalties, new compliance/reporting requirements, and more government shifting of costs through Medicare and Medicaid expansion. These factors are all outside the control of Consumers Energy. Even with all the employee and retiree health

plan design and premium contribution changes made annually by the Company over a number of years, including the move to Live Well 365 program incentives, health care costs for the Company are still expected to continue increasing annually at a rate two to three times that of general CPI inflation. The assumption that health care costs will only increase at the general rate of inflation has not been the actual experience for many years and is not expected in the foreseeable future.

**Q. Are increases in health care costs being experienced both locally and nationally?**

A. Yes. While increases in health costs have moderated, both local and national health care costs continue to increase at rates greater than general CPI inflation.

**Q. Are the significant increases in health care costs limited to active employees?**

A. No. Health care costs are also increasing at a rate higher than the general CPI inflation for retirees for the same reasons cited earlier. In fact, retiree expenses are generally increasing at higher rates because of retirees' older ages and the resulting increases in utilization, particularly in the use of prescription drugs, including higher-priced specialty prescription drugs. The projected increases for active employee health care, like projected increases for retiree health care, are substantial, expected to occur, and largely beyond the control of the Company.

**Q. Please describe the development of the expense levels for active employee life insurance and LTD costs included in Exhibit A-64 (KKG-1), page 1, line 4.**

A. For 2024, the Company used inflation factors of 3.2%. In 2025, the Company used 2.4%, and for 2026, 2.5% was used. These expense estimates are reasonable as both life insurance and LTD premium costs are based on wage and salary levels and changes to this coverage throughout the year. The 3.2%, 2.4%, and 2.5% annual increases represent the normal,

expected merit increases in salaries/wages, increases due to salary adjustments made for job changes and promotions throughout the year, any upward movement in Company-paid life insurance coverage in each annual enrollment period, and increases in premium rates due to plan experience.

**Q. What has the Company done to control the increase in active employee and retiree health care, life insurance, and LTD expenses?**

A. The Company has aggressively managed these benefit costs for more than a decade. Significant changes have been made to all health care, life insurance, and LTD plans since the introduction of the Benefit by Choice program first implemented in 2002, which offered employees and retirees different levels of health, life, and LTD coverage. A summary of various changes made to manage the cost of the Company's health care plans offered to employees and retirees from 2002 through 2024 follows:

- Reduced the number of dental plan offerings by consolidating to one plan;
- Implemented additional specialty prescription savings programs to reduce member and Company costs;
- Reduced the number of healthcare plan offerings by eliminating two health maintenance organization ("HMO") plans;
- Joined prescription drug collaborative to improve efficiencies on pricing, customer service, and access to affordable prescription drug coverage;
- Streamlined all benefit plans to 80% coverage levels;
- Offered a telemedicine option for those seeking treatment for non-emergent conditions;
- Increased employee/retiree premium contribution levels annually;
- Implemented Preferred Provider Organization ("PPO") plans, providing discounted networks to all participants;
- Reduced the level and number of PPO plan benefit coverage levels from 90%, 80%, and 70% to 85% and 70%;

- Reduced HMO plan benefit coverage levels from 100% to 90%;
- Increased, on several occasions, employee/retiree PPO and HMO plan design cost sharing provisions including medical/dental deductibles, out-of-pocket limits, office copays, urgent care copays, and emergency room copays;
- Switched to Maintenance of Benefits ("MOB") coordination;
- Required covered spouse working full-time to have own employer coverage primary;
- Negotiated administrative fees and insured plan premium rates annually, and bid in the health plan market to improve pricing;
- Increased employee/retiree prescription drug benefit cost sharing through incentive four-tier plan designs, higher prescription drug copays and coinsurance, and use of an exclusive network for specialty drugs;
- Implemented prescription drug management programs including full-menu, dynamic-based coverage management programs, mandatory use of mail order, safety/efficiency provisions, and regular market bids for pricing through an employer collaborative;
- Implemented health and disease management programs and added case management;
- Implemented a Company-defined dollar contribution plan management approach;
- Eliminated duplicative, higher cost health plan offerings on several occasions;
- Introduced informed consumerism, cost information, and credible health resources;
- Used enhanced technology for more timely determination of plan eligibility and coverage;
- Implemented access-only retiree health care benefits for new hires (no Company subsidy);
- Implemented preventive benefits with no cost sharing, included the mandated changes required under the Affordable Care Act ("ACA");
- Implemented and promoted enrollment in a CDHP with an HSA;
- Increased premiums and out-of-pocket limits;

- In 2018, implemented new total well-being program called Live Well 365. This program allows employee/preMedicare retirees to be engaged in their total well-being through a variety of well-being activities including, but not limited to, preventive exam, well-being assessment, physical challenges, and a variety of other activities available to increase year-round engagement. For those participants who complete level 1 of the Live Well 365 program, they remain in a higher benefit coverage level or receive an additional Company HSA contribution. Employees/preMedicare retirees that do not participate in Live Well 365 are moved to a higher out-of-pocket cost benefit coverage level or do not receive the second Company HSA contribution;

- Separated employee/retiree medical and dental plans to minimize reporting and compliance costs required by the ACA;

- Changed insured HMO plans to self-insured HMO plans; implemented an ongoing medical/dental/vision plan dependent audit process to ensure only eligible employees, retirees, and their dependents are covered by these plans;

- Secured improved prescription drug pricing and plan consulting services as part of membership in a large prescription drug employer prescription drug purchasing collaborative;

- Made plan design changes to Salaried Active Medical plans to out of pocket limits so Union and Salaried plans match;

- Implemented premium decreases in both the Salaried Active Community Blue Medical and the Aetna Traditional Medical Plan for Retirees;

- Converted Active, Retiree, Dependent Life and AD&D from The Hartford to MetLife;

- Moved to Age Banded rates for Retiree Life (includes both Employer and Retiree contributions); and

- Eliminated eligibility for Salaried Retiree Life – Employer Paid for those who retired on/after 1/1/2024. They may still participate in Retiree Life, but at their own cost.

**Q. What changes were made to the 2020 health care plans?**

A. In 2020, the Company discontinued offering HMO plans for active employees. This change was due to declining enrollment and higher medical and prescription costs in the HMO plans. Active employees had the option to choose from three other high-quality PPO plans for 2020 coverage. The PPO plans offered an expanded network of providers both

in and out-of-network. Active employees who elected the CDHP had the ability for saving options for current and future health care expenses through an HSA. The employee share of health care plans increased.

**Q. What changes were made to the 2020 health care plans due to the COVID-19 pandemic?**

A. The Company incorporated the following health care changes related to the COVID-19 pandemic. The coverage for COVID-19 Diagnostic Testing and Services required under Section 6001 of the Families First Coronavirus Response Act (the "FFCRA"), as amended by Section 3201 of the Coronavirus Aid, Relief, and Economic Security Act (the "CARES Act") and associated subsequently issued guidance (together, the "Diagnostic Coverage Mandate") required the Company to cover certain diagnostic and preventive services related to COVID-19 without imposing any cost-sharing requirements, requiring prior authorization, or imposing other medical management requirements. Effective March 18, 2020, the Company provided coverage in accordance with the applicable requirements of the Diagnostic Coverage Mandate through the duration of the public health emergency related to COVID-19 as declared by the Secretary of the United States Department of Health and Human Services.

Effective from March 18, 2020 through June 30, 2020, the Company had to provide coverage for treatment related to a diagnosis of COVID-19 at no cost (i.e. without cost sharing) to participants and their covered family members. Effective from March 18, 2020 through June 30, 2020, the Plan provided coverage for telehealth and online visits at no cost (i.e. without cost sharing) to Plan participants and their covered family members.

**Q. What changes were made to the 2021 health care plans?**

A. In response to the COVID-19 pandemic, the Company continued to offer coverage for COVID-19 diagnostic testing and services without imposing any cost-sharing requirements for employees and covered family members. The Company did not make any significant changes to the health care plans and employee premium contribution for health care. The Company continued to offer quality health care coverage for employees to ensure a healthy workforce to better serve customers.

**Q. What changes were made in the 2022 health care plans?**

A. In response to the COVID-19 pandemic, the Company continued to offer coverage for COVID-19 diagnostic testing and services without imposing any cost-sharing requirements for employees and covered family members. The Company did not make any significant changes to the health care plans and employee premium contribution for health care. The Company continued to offer quality health care coverage for employees to ensure a healthy workforce to better service customers.

**Q. What changes were made to the 2023 health care plans?**

A. In 2023, the Company added Domestic Partner Coverage to our Health Care Plans. This is an important benefit to offer employees to ensure our benefits attract and retain a diverse workforce. The additional coverage will result in engaged employees and excellent service for customers. Also, the Company increased health care plan designs (deductible, out-of-pocket limits, and prescription copays) for the traditional PPO plan for both union and salaried coworkers. The Company increased health care premiums for the CDHP and eliminated one of the dental providers to improve overall dental costs. Lastly, the Company continued to utilize a cost-savings plan for certain Specialty Drugs through our

prescription provider. Overall, the Company is continuously managing its health care vendors for cost efficiencies, implementing reasonable health care plan design and premium increases, and eliminating choice on the dental plans.

**Q. What changes were made to the 2024 health care plans?**

A. In 2024, the Company made a plan design change in the Salaried Active Medical plans so the out-of-pocket limits for both Union and Salaried employees are now the same. In addition, changes were made to decrease premiums in the Salaried Active Community Blue Medical for active employees.

**Retiree Health Care and Life Insurance**

**Q. Would you please explain your Exhibit A-64 (KKG-1), page 1, line 5, for retiree health care and life insurance, which begins with ($33,761,000) in 2023?**

A. Exhibit A-64 (KKG-1), page 1, line 5, reflects the actual 2023 and projected 12-month period ending October 31, 2026, gas utility retiree health care and life insurance expenses under ASC 715 (formerly known as FAS 106 expense). Each of the annual expense levels shown on line 5 is the total of two separate items which make up the total expense. Each year's expense contains an ASC 715 expense calculation and an actuarial services expense.

**Q. How does the Company determine its ASC 715 expense for retiree health care and life insurance?**

A. The expense is determined using actuarial analysis that is performed in accordance with ASC 715. Consumers Energy follows GAAP for its financial statements. Under the provisions of GAAP, ASC 715 describes the methodologies and assumptions required to properly calculate and account for retiree health care and life insurance expense which includes evaluation of market conditions at each of the plan's measurement dates. The calculations required by the accounting standards are performed at least annually by the

plan's actuary, Aon, using information specific to the Company's OPEB plan. In addition, the Company's auditor rigorously reviews the process to ensure compliance with GAAP and ASC 715.

ASC 715 requires an annual determination of retiree health care and life insurance expense (OPEB expense or formerly FAS 106 expense). The expense is determined based on actuarially reviewed employee census data, the plan provisions, plan assets, and certain other actuarial assumptions. Year-end disclosure information is also produced, based on these accounting standards, to provide a reconciliation of plan assets and liabilities at the end of the Company's fiscal year. For this gas rate case, OPEB were measured in January for the year-end 2023.

**Q. What are the components of the annual ASC 715 retiree health care and life insurance expense?**

A. There are four components of the annual ASC 715 retiree health care and life insurance expense: (i) service cost; (ii) interest cost; (iii) expected earnings on plan assets; and (iv) amortization of gains and losses, prior service costs or credits, and any transitional amounts. Service cost represents one year's expected benefits earned by active covered employees. Interest cost represents interest on the plan's benefit obligation (its liabilities) due to the passage of time. There is also an assumption made for the expected rate of return on plan assets. This rate of return assumption is intended to be a long-term assumption based upon the best estimate of long-term expected investment earnings of the plan assets. The last component represents amortization of various plan experiences that were not anticipated by the actuarial assumptions.

In order to calculate the plan's total benefit obligation and annual ASC 715 retiree health care and life insurance expense, the actuary uses a number of assumptions including health care inflation trend rates, mortality table, the rate of employee retirements from the Company, the actual retiree health care and life insurance claims of the Company, a discount rate, and the expected contributions to the plan. The methods used to set assumptions are generally consistent, while the values of each assumption are determined by the Company each year and reviewed by the Company's auditors and actuary. The method used to set the discount rate and expected return on plan assets is the same as the method used for the pension plans, as discussed above.

**Q. Are actuarial and administrative expenses included in Exhibit A-64 (KKG-1), page 1, line 5?**

A. Yes. An annual expense for the actuarial and administrative services provided for the retiree health care and life insurance plans is included in Exhibit A-64 (KKG-1), page 1, line 5.

**Q. What changes were made to the 2020 retiree health care plans?**

A. The preMedicare retirees had the same health care plan options as the active union and nonunion employees. The pre-Medicare retirees no longer had the option to select the HMO plans. The pre-Medicare retirees had the same COVID-19 health care plan changes as the active union and nonunion employees. The Medicare eligible retirees who received a Company subsidized HRA received a 2% increase into their HRA. These retirees select their retiree health care coverage through an individual Medicare marketplace. The private Medicare marketplace specializes in assisting retirees select the best quality healthcare plan

options at the most affordable price. The HRA subsidy amount was allotted based on years of service and hire date.

**Q. What changes were made to the 2021 retiree health care plans?**

A. The pre-Medicare retirees had the same health care plan options as the active union and nonunion employees. The pre-Medicare retirees no longer had the option to select the HMO plans. The pre-Medicare retirees had the same COVID-19 health care plan changes as the active union and nonunion employees. The Medicare eligible retirees who received a Company subsidized HRA received a 2% increase into their HRA. These retirees selected their retiree health care coverage through an individual Medicare marketplace discussed above. The HRA subsidy amount was allotted based on years of service and hire date.

**Q. What changes were made to the 2022 retiree health care plans?**

A. The pre-Medicare retirees had the same health care plan options as the active union and nonunion employees. The pre-Medicare retirees had the same COVID-19 health care plan changes as the active union and nonunion employees. The Medicare eligible retirees who receive a Company subsidized HRA received a 2% increase into their HRA. These retirees select their retiree health care coverage through the individual Medicare marketplace discussed above. The HRA subsidy amount was allotted based on years of service and hire date.

**Q. What changes were made to the 2023 retiree health care plans?**

A. The pre-Medicare retirees have the same health care plan options as the active union and nonunion employees. The pre-Medicare retirees have the same COVID-19 health care plan changes as the active union and nonunion employees. The Medicare eligible retirees who

receive a Company subsidized HRA will receive a 2% increase into their HRA. These retirees select their retiree health care coverage through an individual Medicare marketplace discussed above. The HRA subsidy amount is allotted based on years of service and hire date. Effective January 1, 2023, the Company is only offering a single dental plan, which allows for lower premiums and access to a wider provider network.

**Q. What changes were made to the 2024 retiree health care plans?**

A. In 2024, changes were made to decrease premiums in the Aetna Traditional Medical Plan for Retirees.

**Q. Do the calculations for the retiree health care and life insurance expense follow the prescribed methodology of ASC 715?**

A. Yes. The amounts are projected based on ASC 715 using information specific to the Company's retiree health care and life insurance plans. For this gas rate case, the OPEB Plan was measured in January 2024 for year-end.

**Q. Has the Company applied the ASU No. 2017-07 Improving the Presentation of Net Periodic Pension/OPEB Costs Standard in this case for OPEB?**

A. Yes, the Company adopted the ASU No. 2017-07 as of January 1, 2017, and has applied the Standard in this case for both Pension and OPEB.

**Q. Please describe the development of the retiree health care and life insurance expense levels that are shown on Exhibit A-64 (KKG-1), line 5, which begins with ($33,761,000) in 2023.**

A. The O&M retiree health care and life insurance expense level shown on line 5 for the gas utility is based upon Aon's actuarial determination of the plan's expense for that period in accordance with ASC 715 plus the cost for actuarial and administrative services related to

these plans. Due to the retiree medical plan changes described earlier, the actual 2023 O&M retiree health care and life insurance expense for the gas utility was ($33,761,000). The projected gas O&M retiree health care and life insurance expense is ($42,702,000) for the test year. Exhibit A-64 (KKG-1), page 2, line 5, column (i), compares the Aon actual calculation of expense with the 2023 actual expense, as adjusted for 2024, 2025, and 2026 inflation, to calculate other adjustments..

**Q. Why is the retiree health care and life insurance expense higher in 2023 and decreasing in the test year?**

A. Year 2023 had higher-than-expected asset returns, which caused the lower projected expense in the test year.

**Q. Would you please explain your Exhibit A-64 (KKG-1), page 1, line 6, for Other Benefits, which begins with $2,493,000 in 2023?**

A. Exhibit A-64 (KKG-1), line 6, reflects the actual 2023 and projected 12-month period ending October 31, 2026 expenses for the gas utility benefits labor, the absence management program, the educational assistance program, the employee assistance program, and the Leaving It Better Award program. The adjustment in Exhibit A-64 (KKG-1), page 2, line 6, column (i), compares the projected test-year expense with the 2023 actual expense, adjusted for 2024, 2025, and 2026 inflation, and the addition of the Leaving It Better Award program to calculate other adjustments.

**Q. Please explain why the absence management program is important to attract and retain employees.**

A. Paid sick leave is needed to attract and retain employees. In 2014, the Company retained Reed Group, now known as Alight, as an external consultant to manage the Company's

absence process. Since the relationship's inception, Alight has been able to improve the absence rate and provide a higher level of standardization, controls, and overall best practices to mitigate risk. Additionally, this streamlined approach ensures a procedure for all employees who need a leave of absence for any purpose.

**Q. Please explain why the educational assistance program is important to attract and retain employees.**

A. Educational assistance programs are widely available from Michigan employers as well as from other utility company employers that Consumers Energy competes with for employee talent. The Company offers partial tuition reimbursement to all employees. It is necessary to continue providing this highly visible, competitive benefit to employees of Consumers Energy to continue attracting and retaining competent employees needed by the Company, particularly considering the large number of retirement-eligible employees at the Company. Attracting qualified employees and retaining this talent maximizes the efficiency of the Company's labor force and reduces costly turnover. Safe, reliable, and affordable gas service begins and ends with the Company's people. Investing in and retaining trained, experienced, and motivated employees' benefits customers as much as, or more than, any investment in infrastructure. Educational assistance is just such an investment. It provides the opportunity for employees to continue their education, which further improves their skills to serve the customers of the Company.

**Q. Please explain why the employee assistance program is important to attract and retain employees.**

A. The Company offers employees, retirees, and dependents access to an assistance program which provides support to help resolve or manage problems that interfere with the ability

to perform at work or in life. The employee assistance program provides a variety of on-line tools, face-to-face interactions, and telephone support. The program is designed to aid with any type of need, distraction, concern, or crisis. The employee assistance program provides legal support, financial information, work-life solutions, online services, and confidential counseling. The goal of the program is to improve the overall total well-being for all the Company's employees and retirees.

**Q. What is the Leaving It Better Award employee recognition program?**

A. The Leaving It Better Award is used to recognize and reward regular salaried, exempt, and non-exempt employees who impact the Company's success by exhibiting the Company's vision and culture in a way that furthers the Company's goals, operational excellence, customer satisfaction, and corporate reputation. Leaders nominate employees and employees can receive a lump sum of up to $4,000.

**Q. Please explain the benefits of the Leaving It Better Award?**

A. This additional employee recognition is a way to show employees that they are valued for their work, increases the level of productivity at work, and reduces employee turnover, which supports improved service to customers. While the Company already provides merit pay increases for employee achievement of goals and objectives and accomplishment of tasks, duties, and responsibilities as set out in an employee's annual performance evaluations, the employee recognition in the form of a Leaving It Better Award provides additional recognition for going above and beyond the everyday expectations to serve the Company and its customers.

**Q. Does this conclude your direct testimony?**

A. Yes.

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

| | | |
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| In the matter of the application of<br>**CONSUMERS ENERGY COMPANY**<br>for authority to increase its rates for the<br>distribution of natural gas and for other relief. | )<br>)<br>)<br>)<br>) | Case No. U-21806 |

# REBUTTAL TESTIMONY

# OF

# KENDRA K. GROB

# ON BEHALF OF

# CONSUMERS ENERGY COMPANY

May 2025

**Q. Please state your name and business address.**

A. My name is Kendra K. Grob, and my business address is One Energy Plaza, Jackson, Michigan 49201.

**Q. Are you the same Kendra K. Grob who previously submitted direct testimony in this case?**

A. Yes.

**Q. What is the purpose of your rebuttal testimony?**

A. My rebuttal testimony will address Michigan Public Service Commission ("MPSC" or the "Commission") Staff ("Staff") witness Shannon Rueckert's recommended disallowance for Leaving It Better Awards ("LIBA"). My rebuttal testimony will also address Attorney General witness Sebastian Coppola's recommended adjustments for projected active health care, life insurance, and long-term disability ("LTD") expenses.

**Q. Are you sponsoring any exhibits with your rebuttal testimony?**

A. No.

**LIBA**

**Q. Staff witness Rueckert's direct testimony, pages 3 to 5, recommends a disallowance of the LIBA program costs. Does Consumers Energy Company ("Consumers Energy" or the "Company") agree with this proposed disallowance?**

A. No. The LIBA program rewards employees with highly effective or better performance ratings for exceeding expectations. Recently centralized under the benefits area, LIBA recognizes efforts like taking on extra work for colleagues on extended leave or handling demanding projects. These awards help the Company retain talent, increase morale, enforces behaviors that support company values and improved performance which in turn

benefits customer service. The Commission should approve the O&M and capital costs for continuing LIBA, as it ultimately reduces overall rate costs for customers.

**Q. On page 4, lines 7 through 9, of his direct testimony, Mr. Rueckert explained that one reason he recommended the LIBA disallowance was that "[p]romotability and salary increases are already incentives to achieve operational excellence." How do you respond?**

A. While merits and annual incentives can promote operational excellence, the LIBA is another tool at the Company's disposal to encourage excellence. It is an instant acknowledgment of exceptional work, reinforcing positive behaviors and motivating employees to maintain high-performance levels. Studies have confirmed that awards differ fundamentally from direct compensation increases, like promotions and merits.[1] And, when designed appropriately, awards can provide further incentive to excel.[2]

**Q. On page 4, lines 15–16, of his direct testimony, Mr. Rueckert also noted that the Company's Employee Incentive Compensation Program ("EICP") already provides short-term incentive compensation for operational goals. Does the Company's EICP serve the same function as the LIBA?**

A. The Company's EICP differs from LIBA in that the EICP is based on pre-determined performance criteria, whereas the Company has more discretion under LIBA to award employees for outstanding performance after the fact. Both the EICP and LIBA provide value to customers, but in different ways.

[1] Jana Gallus & Bruno S. Frey, *Awards: A strategic management perspective*, 37 STRATEGIC MANAGEMENT JOURNAL 1527 (2016).
[2] Indeed Editorial Team, *Rewards and Incentives in the Workplace (Advantages and Examples)*, at https://www.indeed.com/career-advice/career-development/rewards-incentives (last visited May 12, 2025).

**Q. On page 3, lines 19 through 21, of his direct testimony, Mr. Rueckert suggests that LIBA is always awarded in a lump sum of $4,000. Is this always true?**

A. No. Awards vary from $250 to $4,000 depending on the nature of the work meriting the award. The Company considers whether a nominee's work benefits the nominee's immediate work area or whether it has a wider department-level or Company-wide impact.

**Q. On page 342 of its March 21, 2025 Order in Case No. U-21585, the Commission recognized the potentially valuable benefits that the LIBA program provides. It did not approve recovery of the LIBA expense in that case but did not preclude the possibility it would approve the expense in other cases. It specifically expressed an interest in how the program has been funded in the past and whether the program has previously been included in rates. How has the program been funded in the past and when did this change?**

A. The LIBA program was funded as a part of individual department labor costs budgets prior to 2024. In 2024, a formal budget at the corporate level was established to centralize the cost of the program and allow for better visibility into the utilization and benefits.

**Q. Staff witness Rueckert's direct testimony, page 5, recommends a disallowance of the LIBA program capital expense of $824,000 for 2024, $702,500 for the 10 months ending October 31, 2025, and $861,000 for the test year ending October 31, 2026. Does the Company agree to the amount of capital listed for those time periods?**

A. No. The Company does not agree with Staff's stated costs that 2024 actual capital amount booked was $590,000. The Company does agree that the amounts listed for the 10 months ending October 31, 2025, of $702,500 and $861,000 for the test year ending October 31, 2026, would be the correct capital projections in this gas rate case. However, the

Commission should not disallow any of the projected capital amounts as the cost of the LIBA program should be included in this case as it does benefit the customer overall in reduced labor costs.

**Active Health Care, Life Insurance, and LTD Expense**

**Q. Please summarize Attorney General witness Coppola's proposed adjustment to Active Health Care Expense, Life Insurance, and LTD Expense.**

A. On pages 184 and 185 of his direct testimony, Attorney General witness Coppola recommends a $2,754,000 reduction in Active Health Care Expense to reflect his calculated impact of program savings on this expense category.

**Q. Do you agree that Active Health Care, Life Insurance, and LTD Expenses should be reduced by $2,754,000 to reflect the program savings reductions?**

A. No. First, the amounts listed in discovery request U21806-AG-CE-0686 and Exhibit AG-65 are gross amounts savings for the assumed plan changes for the listed items. So, the amounts are both electric and gas amounts before capitalization. $2,754,000 gross would only be gas operating and maintenance ("O&M") of $483,000. Second, the Attorney General is assuming that these amounts are not included in the projections for this case. This is not true; these savings are included as the Company is still experiencing health care expense increase over the plan changes. Healthcare costs are still trending well above the inflation rates that were used to set the expense in this case. The actual gas O&M portion of the Active Health Care, Life Insurance, and LTD Expense for 2024 was $19.860 million, while the projected expense for 2024 was $18.921 million. The Company's projected Active Health Care Expense remains reasonable. The Commission should not accept the

Attorney General's reduction amount of $2,754,000 for Active Healthcare, Life Insurance, and LTD expenses.

**Q. Does this complete your rebuttal testimony?**

A. Yes.

MR. RUSZKIEWICZ: The Company's next witness is Quentin A. Guinn. Mr. Guinn also adopted the testimony of Corey Ballinger for the Company. The adopted testimony of Mr. Guinn and -- I should back up here. I apologize.

Based on the stipulation of the parties, the Company moves to bind in the testimony of Mr. Guinn, and the adopted testimony of Corey Ballinger from Mr. Guinn, consists of a cover page and 47 pages of prefiled direct testimony. I'm sorry. I'm kind of jumping around here. But I will do the exhibits next for the adopted testimony. And those consist of Exhibits A-12 Schedule B-5.2, A-27, A-28, A-29.

Now moving to Mr. Quentin's testimony that he filed on his own behalf, he had a cover page and 38 pages of prefiled testimony for direct, and he also had confidentially -- confidentially filed and revised rebuttal testimony, consisting of a cover page and nine pages of prefiled testimony.

The Company also moves to admit his exhibits, which consist of Exhibit A-12 Schedule B-5.6, Exhibit A-68, Exhibit A-69, and Exhibit A-70. Thank you.

JUDGE VARCHETTI: All right. Are there any objections to binding in the direct and confidential rebuttal testimony of Mr. Guinn, his adopted testimony

which adopted the testimony of Mr. Ballinger, or any of the exhibits associated with Mr. Guinn or Mr. Ballinger?

Hearing none, then, the testimony and the exhibits are admitted.

MR. RUSZKIEWICZ: Thank you.

(Direct Testimony and Adopted Testimony bound in)

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

| | | |
|---|---|---|
| In the matter of the application of<br>**CONSUMERS ENERGY COMPANY**<br>for authority to increase its rates for the<br>distribution of natural gas and for other relief. | )<br>)<br>)<br>)<br>) | Case No. U-21806 |

**DIRECT TESTIMONY**

**OF**

**QUENTIN A. GUINN**

**ON BEHALF OF**

**CONSUMERS ENERGY COMPANY**

December 2024

**Q. Please state your name and business address.**

A. My name is Quentin A. Guinn and my business address is One Energy Plaza, Jackson, Michigan 49201.

**Q. By whom are you employed and in what capacity?**

A. I am employed by Consumers Energy Company ("Consumers Energy" or the "Company") as Principal Metrics & Analytics Specialist.

**Q. What are your responsibilities as Principal Metrics & Analytics Specialist for Consumers Energy?**

A. As Principal Metrics & Analytics Specialist, I am responsible for providing support and direction for Facilities, Real Estate, and Administrative Operations strategy development, compliance, resource planning, and regulatory proceedings. The Facilities execution plan ranges from activities related to gas operations to those involving corporate operational areas of Consumers Energy. Facilities' asset portfolio consists of over 55 buildings and includes the corporate office, storerooms, distribution centers, maintenance garages, service centers, welding and fusion workshops, learning and development buildings, coal generation, wind generation, gas compression, and hydroelectric sites. My responsibilities include regulatory compliance, rate case execution, corporate policy administration, organizational vision, and resource planning for field execution.

**Q. What is your formal educational experience?**

A. I hold a bachelor's degree in economics from Yale University, located in New Haven, Connecticut, and a Juris Doctorate degree from Washington University, located in St. Louis, Missouri.

**Q. Would you please describe your previous work experience?**

A. In 1999, I started my career at Consumers Energy as a Contracts Analyst. In 2000, I began a series of changing roles, with increasing responsibility, from Contracts Supervisor to Director of Contract Services. In each successive role, I led teams of Contract Analysts and Contract Administrators who were responsible for a broad range of construction, maintenance, consulting, information technology, and engineering contracts. The responsibilities of these teams included sourcing and evaluating contractors and consultants, developing scopes of work, competitively bidding work, negotiating agreements, and administering contracts. In 2013, I began work in a series of successive roles focused on data, analytics, performance, and work management culminating in my current role as Principal Metrics & Analytics Specialist.

**Q. What is the purpose and scope of your direct testimony in this proceeding?**

A. The purpose of my direct testimony is to support the Company's costs related to the Gas business portion of Facility Operations ("Facilities"). I will:

- Describe the Gas Operations Support function;
- Describe the methodology employed by Facilities for evaluating the health of its various facilities;
- Support the reasonableness and prudence of the capital expenditures for Asset Preservation for the historical year ended December 31, 2023, the bridge period beginning January 1, 2024, and ending October 31, 2025, and the projected test year ending October 31, 2026; and
- Support the reasonableness and prudence of the Operation and Maintenance ("O&M") expenses for Facilities, Real Estate, and Administrative Operations for the historical year ended December 31, 2023, the bridge period beginning January 1, 2024, and ending October 31, 2025, and the projected test year ending October 31, 2026.

**Q. Have you previously testified in a Michigan Public Service Commission ("MPSC" or the "Commission") proceeding?**

A. Yes. I have provided testimony on behalf of Consumers Energy Company in Case Nos. U-21148, U-21224, U-21308, U-21389, U-21490, and U-21585.

**Q. Are you sponsoring any exhibits with your direct testimony?**

A. Yes. I am sponsoring the following exhibits:

| | | |
|---|---|---|
| Exhibit A-12 (QAG-1) | Schedule B-5.6 | Summary of Actual & Projected Capital Expenditures; |
| Exhibit A-68 (QAG-2) | | Summary of Actual and Projected O&M Expenses; |
| Exhibit A-69 (QAG-3) | | Detailed List of Projected Gas Capital Expenditures; |
| Exhibit A-70 (QAG-4) | | Service Center Projects – Plan Summaries. |

**Q. Were these exhibits prepared by you or under your direction or supervision?**

A. Yes.

**Q. Please describe the exhibits you are sponsoring.**

A. Exhibit A-12 (QAG-1), Schedule B-5.6, details the actual and projected capital expenditures related to Gas Operations Support. Exhibit A-68 (QAG-2) details the O&M costs related to Gas Operations Support. Exhibit A-69 (QAG-3) identifies Gas Operations Support Programs and the projected capital expenditures related to those projects and programs. Exhibit A-70 (QAG-4) details the alternatives considered and customer benefits of each of the three service center projects outlined in this case.

**Q. Please explain the Gas Operations Support function.**

A. The Gas Operations Support function consists of the following support organizations: Fleet Services, Facilities, Real Estate, and Administrative Operations. Gas Operations Support

acquires, constructs, and maintains fixed assets required to operate the functional areas of the business that serve the Company's customers.

**Q. Are you addressing all support organizations related to Gas Operations Support in your direct testimony and exhibits?**

A. No. Fleet Services will be addressed in the testimony of Company witness Corey E. Ballinger.

**Q. What is the function of the Facilities organization?**

A. Within Gas Operations Support, Facilities manages, maintains, and operates 55 buildings comprising 3.2 million square feet of building space across the state of Michigan that allow the Company to serve customers across the state in an efficient and effective manner.

**Q. How have Company facilities changed over time?**

A. The Company experienced major growth in the area of Facilities during the 1950s and 1960s. Nearly half of its buildings were built or acquired during this period and remain in operation today. As a result, many of these buildings are now over 50 years old. The Company made no significant investment in its facilities and initiated no major renovations or construction of new buildings between 1970 and 2000. In 2003, the Company constructed its One Energy Plaza headquarters building in Jackson. This construction marked the adoption of the open office concept (i.e. fewer hard wall offices) at the Company which, among other reasons, was adopted to foster a more collaborative work environment. Between 2000 and 2016, the Company also closed many facilities including 22 service centers across Michigan to adapt to shifting population trends in the state and optimize service to customers.

**Q. What structural concerns or problems do these aging structures and facilities create for the Company?**

A. Multiple major systems throughout these facilities, such as boilers, chillers, cranes, elevators, emergency generators, heating, ventilation, and air conditioning ("HVAC") systems, lighting, power distribution, paving, roofing, Uninterruptible Power Systems, and vehicle hoists are beyond their useful lives. Further, building materials in the facilities contain hazards such as asbestos and lead paint. Repairs on such aging infrastructure are not always cost effective and can lead to lengthy projects and significant renovation or replacement of entire structures. It is increasingly difficult to identify and obtain adequate parts and to further locate the necessary expertise to work on this aging equipment. In addition, these facilities were not designed to meet modern standards of energy efficiency.

**Q. What concerns or problems do these aging structures and facilities create for the Company's customers?**

A. The population and infrastructure of the State of Michigan look much different than they did in the 1950s and 1960s. In 1950, the population of Michigan was 6,407,000 with growth focused in urban areas. The state's current population is now over 10 million, with much of the growth since the 1960s having occurred in suburban areas. The Company regularly assesses the optimal location of its facilities needed to effectively serve customers and minimize response times. The Lansing Service Center Project, discussed in detail later in my testimony, originated from this assessment process.

**Q. What process does Consumers Energy utilize to evaluate whether to make capital investments in facilities?**

A. The Company has been using a formal assessment process for several years that evaluates whether to invest in a facility by studying each facility's overall health. The Company plans to continue using this process and is enhancing it by incorporating the operational priorities of the Facilities organization's internal business partners. Given the evolving nature of the workforce (i.e., with hybrid work) the Company is working on strategies to ensure its facilities are right sized for the needs of the work.

**Q. What is the formal assessment process related to facility health?**

A. A formal assessment process was established in 2016 to determine the need for capital investments in facilities. The assessment process is re-evaluated every two years resulting in minor updates to the methodology to reduce subjectivity in scoring. The most recent assessment was completed in 2022. The Facilities Department consists of qualified, trained, and certified experts in architecture, HVAC, plumbing, and electrical that conduct the assessment. In that process, an evaluation is made, on a multi-category scale, of certain conditions and characteristics of the structure and functions of the facility being assessed. For each facility, each condition and characteristic is scored (with a score of 1 to 5 per category), and then the facility is ranked on a multi-category scale (with an 80-point maximum score).

**Q. What categories are included in the evaluation process of the Company's facilities?**

A. Categories that are evaluated include: (i) safety (such as asbestos or other hazardous materials, traffic flow, and compatibility with surrounding areas); (ii) quality (such as workplace efficiency, employee comfort, and employee attraction and retention); (iii) cost

(such as facility operating costs, space optimization, and energy efficiency); (iv) delivery (such as response times, driving distance within service territory, and sustainability of operations); and (v) morale (such as employee pride, wellness, and retention).

**Q. How is the quality of each category identified above established?**

A. The facility evaluated will fall within one of three quality designation categories depending on the score received. A score above 64 is designated as "Good"; a score of 48 to 64 is designated as "Serviceable," meaning that investment and/or replacement is needed; and a score under 48 is designated as "Poor," meaning that there are multiple systems failing at the facility. Facilities designated as "Poor" are typically candidates for replacement.

**Q. What is the next step in the facility assessment?**

A. Once the facility is initially evaluated and receives a quality designation, operational departments of the business then review and validate the raw scored ranking and adjust the ranking to reflect forecasted needs of the business. Facilities finalizes the score, and any facility that scores below a minimum acceptable level, 48 out of 80 points, may be identified for renovation or replacement.

**Q. How does the Facilities organization consider the business needs of its internal business partners when selecting locations for Facilities work?**

A. The Facilities organization considers business partner needs by meeting on a regular basis with business partners to review their business plans and the resulting impacts on the facilities necessary to support these plans. The process begins with a 10 Year Long Term Facilities Plan. This plan is maintained by the Facilities organization and contains fundamental information about each facility such as the year the building was constructed, estimated years of useful life remaining in the building, and dates of major milestones in

the life of the building (e.g. significant renovations and building additions). Facilities organization engineers and other technical experts across the Company (e.g. Company environmental analysts) generate the health assessments and develop capital investment priorities based on the health assessments (e.g. replacement of specific assets at specific buildings, preventive maintenance of specific building systems, work on a building envelope). These capital investment priorities are then reviewed by business partners for alignment with their business plans and can become planned projects based on this collaboration between the Facilities organization and business partners. While considerable engineering rigor is applied to developing the facility health assessments, business partner priorities do affect the ultimate list of projects. The Kalamazoo Service Center Project included in this rate case, for instance, was elevated in priority to address hazardous material issues and negative employee engagement identified by business partners at the Kalamazoo Service Center.

**Q. Does this process ensure priority is given to Facilities projects critical to ensuring the Company can serve its customers?**

A. Yes. The facility health assessments and aforementioned planning process produces a prioritized list of facilities for renovation or replacement that is aligned with both the need to preserve and maintain facilities assets and support business plans in providing optimal customer service. Buildings that are in poor condition or are otherwise suboptimal negatively impact the Company's ability to serve customers.

**Q. Are there situations in which prioritization of projects might change?**

A. Yes. For example, several years ago the Company reprioritized development of a service center in Tawas to provide timely support to customers in the greater Tawas region and to

reduce the workload impact on local first responders during response to emergency utility events. In another example, the Company revised its plans for the Kalamazoo Service Center Project included in this case. In this instance, after examining the impacts of the COVID pandemic on the workforce and changes the pandemic brought in how work is performed, the Company revised its original plan to replace the Kalamazoo Service Center and instead decided to renovate portions of it as many of the building modifications originally proposed became more costly due to supply issues and were also deemed no longer necessary to support the post-COVID workforce.

**Q. Is the Company taking steps to ensure its facilities are right-sized given changes in the working environment?**

A. Yes. The Company is monitoring the use of its facilities in a post-COVID work environment. As the pandemic has subsided, multiple internal organizations have established expectations for in-person work at Company facilities. As a result, Company facilities are continuously evaluated for alignment with current and anticipated work trends. In cases where underutilized workspace has been identified, the Company has divested or examined divesting such space. For example, in 2020, the Company terminated lease agreements for over 30,000 square feet of previously leased office space at the Commonwealth Commerce Center in Jackson. The Company will continue to evaluate space utilization with the goal of eliminating underutilized space and aligning business needs with space requirements.

**Capital Spending Overview**

**Q. What programs are included in the projected capital expenditures for Facilities?**

A. As demonstrated in Exhibit A-12 (QAG-1), Schedule B-5.6, Facilities capital spending is divided into two programs: (i) Asset Preservation; and (ii) Other Equipment. Capital spending is broken down into multiple standard cost categories, including contractor, labor, materials, business expenses, and other (loadings, chargebacks). Most Facilities capital spending, as reflected in Exhibit A-12 (QAG-1), Schedule B-5.6, is for Asset Preservation, which is broken down into four portfolio categories: emergent repairs, asset replacement, new construction, and renovations.

***Other Equipment***

**Q. What is included in the Other Equipment program?**

A. Other Equipment includes capital investments for wellness equipment; computer equipment; print equipment; Real Estate organization tools and equipment; Supply Chain organization tools and equipment; and Facilities organization tools. As shown in Exhibit A-12 (QAG-1), Schedule B-5.6, the Company is projecting to spend $1,148,000 on Other Equipment in the 22-month bridge period and $652,000 on Other Equipment in the projected test year.

**Q. Can you elaborate on what the various categories of Other Equipment spending represent?**

A. Wellness Equipment consists primarily of equipment used by Operations personnel and others in the Company's fitness centers. Computer Equipment includes computers acquired for use by Operations Support personnel outside of routine lifecycle replacements. These include acquisitions of computer equipment obtained for a specialty use (e.g. a

plotter) or replacement of computer equipment that fails prematurely for various reasons. Print Equipment consists of large copying and printing equipment for the Company's Administrative Operations and Mail Room. Real Estate Tools and Equipment consists primarily of survey equipment. Supply Chain Tools and Equipment consists of tools and equipment acquired for material storerooms such as shelving.

**Q. How did the Company determine this level of investment for Other Equipment?**

A. Levels of investment are set to meet identified needs of the business. The Facilities organization considers business partner needs by meeting on a regular basis with business partners to review their business plans.

***Emergent Repairs***

**Q. What capital expenditures are included in the Emergent Repairs portfolio category?**

A. Emergent Repairs includes unplanned corrective maintenance and break fix repair of assets. As shown in Exhibit A-69 (QAG-3), the Company is projecting to spend $1,463,000 in the 22-month bridge period and $1,939,000 in the projected test year on emergent repairs. The Company maintains data on the age, condition, and maintenance history of its major building system assets. This data, in conjunction with historical spend, is used to forecast projected spend on unplanned corrective maintenance and break fix repair of assets.

***Asset Replacement***

**Q. What capital expenditures are included in the Asset Replacement portfolio category?**

A. The Asset Replacement portfolio category includes capital replacement of paved surfaces such as parking lots and driveways; roofing; mechanical and electrical equipment in buildings; and furniture. As shown in Exhibit A-69 (QAG-3), the Company is projecting

to spend $17,021,000 on Asset Replacements in the 22-month bridge period and $7,838,000 on Asset Replacements in the projected test year.

**Q. How are Asset Replacement projects targeted?**

A. Similar to the aforementioned facility health assessments, asset condition assessments are performed by Facilities engineers on a regular basis. For example, for roofing assets, a portion of roof sections is inspected annually such that all roofs are inspected once every three years. The condition of each assessed asset is ranked following standard industry-recognized methodologies. Those assets assessed to be below acceptable condition are targeted for renovation or replacement.

**Q. How does the Company identify locations for paving projects?**

A. The condition of paving assets is evaluated following standard industry practices on a rolling five-year basis with a condition assessment performed annually for 20% of Company sites. Paving assets are prioritized for replacement based on the lowest assessed condition index score. Paving projects may include other related enhancements to paved surfaces such as new drainage or new lighting.

**Q. How did the Company determine the amount of needed investment in paving projects for the bridge period and the test year?**

A. The total amount of needed investment in paving projects is established using the five-year historical average spend. The condition assessments are then used to determine how that spend is allocated. Specific paving sections are identified for replacement and cost estimates are prepared utilizing historical data from similar paving asset replacement projects performed during the last five years.

**Q. How does the Company identify locations for roofing projects?**

A. The condition of roofing assets is evaluated on a rolling three-year basis with a visual inspection and detailed infrared inspection performed annually for 33% of Company sites. Roofing assets are prioritized for replacement based on the lowest assessed condition index score.

**Q. How did the Company determine the amount of needed investment in roofing projects for the bridge period and the test year?**

A. The total amount of needed investment in roofing projects is established using the five-year historical average spend. The roof condition assessments are then used to determine how that spend is allocated.

**Q. How does the Company identify locations for mechanical and electrical projects?**

A. The condition of mechanical and electrical assets is evaluated by Facilities engineers for all Company sites. Based on the results of these evaluations, targeted maintenance work is performed on mechanical and electrical assets. Where the condition of mechanical and electrical assets is determined to be below an acceptable threshold for targeted repair or maintenance, the mechanical and electrical assets are prioritized for replacement based on the results of these evaluations. The condition of these assets is determined to be below an acceptable threshold for targeted maintenance once the cost of maintenance exceeds the cost of replacement and/or the risk of obsolescence of replacement parts becomes too great.

**Q. How did the Company determine the amount of needed investment in mechanical and electrical projects for the bridge period and the test year?**

A. The total amount of needed investment in mechanical and electrical projects is established using the five-year historical average spend. Cost estimates are then prepared utilizing

historical cost data for each of the mechanical and electrical assets prioritized for replacement. Cost estimates are prepared utilizing historical data from similar mechanical and electrical projects performed during the last five years. Whether the facility in which the mechanical and electrical project is being performed serves only Company gas customers, only Company electric customers, or serves combination electric and gas customers impacts how mechanical and electrical project costs are allocated. In this case, the decrease from $5,552,000 in the 12-month bridge period ending December 31, 2024 to $2,187,000 in the projected test year is largely attributable to the fact that the mechanical and electrical projects being performed during the 12-month period ending October 31, 2026 are being performed primarily in Company facilities that serve only electric customers. Mechanical and electrical projects performed during the historical year were performed primarily in Company facilities that serve only gas customers and facilities that serve combination electric and gas customers.

**Q. How does the Company identify locations for elevator projects?**

A. The condition of elevator assets for all Company sites are evaluated by outside consultants and subject matter experts. Elevator assets are prioritized for replacement based on the results of these evaluations utilizing a condition assessment score of 1 to 5. Elevators with an assessment score of 3 or below are targeted for modernization or replacement.

**Q. How did the Company determine the amount of needed investment in elevator projects for the bridge period and the test year?**

A. The total amount of needed investment in elevator projects is established using the five-year historical average spend. Cost estimates are then prepared utilizing historical cost data for each of the elevator assets prioritized for modernization. Cost estimates utilize

historical data from similar elevator asset projects performed during the last five years. The cost per individual elevator modernization or replacement varies from year to year depending on the number of floors served by the elevator, weight rating of the elevator, and elevator drive type. Whether the facility in which elevator modernization is being performed serves only Company gas customers, only Company electric customers, or serves combination electric and gas customers also impacts how elevator asset project costs are allocated. In this case, the increase from $55,000 in the 12-month period ending December 31, 2024 to $445,000 in the projected test year is largely attributable to the fact that the elevator asset projects being performed during the 12-month period ending October 31, 2026 are being performed primarily in Company facilities that serve only gas customers. Elevator asset projects performed during the historical year were performed primarily in Company facilities that serve only electric customers and facilities that serve combination electric and gas customers.

**Q. How does the Company identify where furniture replacements are needed?**

A. Furniture replacement is determined based on business need. Subject matter experts evaluate business unit requirements and existing furniture. Where the existing furniture does not meet business unit requirements the furniture is identified for replacement.

**Q. How did the Company determine the amount of needed investment in furniture for the bridge period and the test year?**

A. Cost estimates are prepared utilizing historical cost data for each of the furniture assets prioritized for replacement. Furniture project cost estimates utilize historical data from similar furniture asset projects performed during the last five years. Furniture materials are redeployed to compatible users when feasible.

***New Construction***

**Q. What capital expenditures are included in the New Construction portfolio category?**

A. The New Construction portfolio category includes major projects to build new structures, either on existing Company property or on new properties the Company acquires. As shown in Exhibit A-69 (QAG-3), the Company is projecting to spend $21,170,000 on New Construction in the 22-month bridge period and $7,199,000 on New Construction in the test year**.**

**Q. Has the Company identified projects in the New Construction portfolio category?**

A. Yes. The Company's New Construction projects are listed in Exhibit A-69 (QAG-3) and are as follows:

- Lansing Service Center
- Hastings Service Center
- Gas City Training
- Gas Construction Project

**Q. Does the Company consider environmental impacts when planning for new construction?**

A. Yes. New buildings incorporate the United States Green Building Council ("USGBC") standards (see usgbc.org), and the Leadership in Energy and Environmental Design ("LEED") standards (see usgbc.org/leed), with specific emphasis on reduced energy consumption, sustainability, and reduced operating cost.

**Q. Do these environmental building standards benefit the Company's customers?**

A. Yes. When compared to conventional construction, buildings designed to LEED standards reduce lifetime energy consumption by 30% or more, resulting in reduced operational costs

which allow customers to pay less for utility costs. In addition, new buildings require less maintenance and are easier to maintain than an aged structure, resulting in an estimated 5% cost reduction. Consumers Energy's recently constructed Coldwater Service Center was designed and built to these standards.

**Q. Describe the Lansing Service Center Project. What is its overall goal?**

A. In this project, the Company has purchased land in a new location and will construct a new facility on that property. This facility will allow the Company to retire its existing facility (which will be demolished and retained to address and abate environmental concerns resulting from the operation of a former Manufactured Gas Plant ("MGP") on the site). This new facility will house many employees currently working out of the existing service center. The Company anticipates a portion of these employees will have a hybrid work arrangement in which the employees perform some work tasks at the Lansing Service Center and some work tasks elsewhere including their homes. Employees with a hybrid work arrangement will require collaborative space and use office desk space with open seating in the facility when they are on-site to work with other personnel.

**Q. What alternatives to the construction of a new Lansing Service Center did the Company consider?**

A. The Company considered the following three alternatives: (1) do nothing; (2) renovate the existing Lansing Service Center; and (3) construct a new facility at a new location, with multiple locations considered. The option to construct a new facility at a new location was determined optimal.

**Q. Why has the Company chosen to build a new Lansing Service Center?**

A. As demonstrated in Exhibit A-70 (QAG-4), a Facilities assessment of the existing Lansing Service Center produced a score of 39, placing the existing Lansing Service Center in the quality designation of "Poor." This information led the Company to rule out a "do nothing" option, and problems with the existing facility's location led the Company to rule out building a new facility on the same site. The existing facility is built on the site of a former MGP, with impacted soil materials underlying the building and other structures. The existing facility is also located within the Grand River flood plain with the building floor elevation three feet below the river's flood stage. Additionally, the existing facility is in a residential neighborhood and is served by a local road network with schools nearby, resulting in large truck traffic being routed through the residential area, which may be a safety hazard for residents (especially children). Crime in the existing area is also a problem as the site has experienced multiple law enforcement incidents involving the pursuit of armed suspects through the property, including areas within the secured perimeter. These incidents have resulted in the Company's inability to move vehicles out of the service center (while police officers were pursuing suspects), and a general level of unease regarding the safety and security of employees.

**Q. Please elaborate on the reasons the Company decided to build a new Lansing Service Center.**

A. As reflected in the scores set forth in Exhibit A-70 (QAG-4), there are several reasons the Company has chosen to relocate the existing Lansing Service Center. These reasons range from the age of the building to customer accessibility. First, the existing service center building was built in 1958. Over time, systems of the building, including major mechanical

and electrical systems, even with regular maintenance and replacement, are beyond their useful lives. Currently, these systems require substantial renovations/replacement. Additionally, the existing service center is located in a residentially zoned neighborhood and due to the location, does not allow Gas Operations to meet customer needs in a timely fashion. Further, the roads (because of the residential zoning) are inadequate for the size of equipment utilized in and out of the service center and there are often children in the vicinity, which creates significant safety concerns. The current site is also located within the floodplain of the Grand River with the finish floor elevation located three feet below the major flooding elevation projected by the Federal Emergency Management Agency. All these considerations negatively impact the Company's ability to dispatch both personnel and equipment to serve customers. Other considerations supporting the decision to construct a new facility, rather than renovate the existing facility, include operating cost reductions, security, and environmental abatement. Because of these factors, the Company has decided to build a new Lansing Service Center at a new location, with the evaluation of potential locations summarized in Exhibit A-70 (QAG-4).

**Q. Can you elaborate further on the security and environmental abatement issues at the Lansing Service Center?**

A. Yes. The site has experienced multiple law enforcement incidents, some involving the pursuit of armed suspects across and through the property, including areas within the secured perimeter. These incidents have resulted in lock-down safety protocol implementation for employees and a resulting general level of unease regarding the safety and security of employees, customers, and others, while on the property and when accessing or leaving the property. Environmental issues arise from the use of the current

Lansing Service Center site as the location of a former MGP regulated under Public Act 451 of 1994, Part 201. This site has historical environmental contamination issues resulting from operation of the MGP, including significant underground impacted soil materials (i.e., coal tar residual). Additionally, the facility contains asbestos insulation for pipe and duct work, asbestos flooring, and has significant areas of lead paint in poor and peeling condition. Given these environmental issues, upgrades to the facility (e.g. carpet replacement and open space enhancement) cannot be cost effectively completed.

**Q. Has the Company engaged in an environmental study for the area contemplated for the new Lansing Service Center?**

A. Yes. The proposed new site for the Lansing Service Center includes previous agricultural use; thus, no environmental impacts are anticipated from this previous use. A Phase 1 Environmental investigation has been completed. The proposed site contains wetland areas and current development plans envision leaving these wetland areas undisturbed. A wetland assessment has also been completed.

**Q. What energy efficiency and waste reduction measures does the Company plan to install at the new Lansing Service Center?**

A. The proposed new Lansing Service Center facility is planned to be designed and constructed to achieve certification under the USGBC, LEED version 4 rating system.

**Q. The Lansing Service Center Project includes the relocation of that facility to a different part of the Lansing metropolitan area. Can you explain what is considered generally when considering relocation of a facility?**

A. Yes. As noted earlier, Company facilities are assessed and scored based on multiple criteria (i.e., safety, quality, cost, delivery, and morale) to provide a holistic score that

informs the Company of the possible need to make investments to make improvements. Facilities with scores falling below the acceptable range are targeted for renovation or replacement. Part of the overall analysis, which is relevant to the Lansing Service Center, is the geographic location of targeted facilities. Geographic locations are analyzed against customer workload distribution within the service territory to determine optimal location for the facility. Facilities that are determined to be mis-located within the customer service territory are evaluated for relocation to a newly constructed site with the goal of improved customer response. Facilities determined to already be optimally located within the customer service territory are evaluated for renovation or reconstruction on the existing site.

**Q. How did the Company determine the new location for the Lansing Service Center?**

A. An analysis of customer distribution across the service territory where the Lansing Service Center is located, and potential service center locations within that service territory, determined the optimal area to minimize response times. This analysis is reflected in Exhibit A-70 (QAG-4). Reducing customer response times lowers fuel costs by minimizing the distance Company employees must travel to job sites. Determining the optimal area to minimize response times also maximizes employee efficiency by reducing labor hours required to reach and service customers. The current location of the Lansing Service Center is offset to the north and east of the optimal location, in a residentially zoned neighborhood, and the current location does not provide readily available highway access. The current location of the Lansing Service Center within the service territory results in increased customer response times, higher fuel costs, and reduced employee efficiency due to increased travel times as explained above. The location for the new Lansing Service

Center will not only be in a more appropriately zoned area but will also provide improved customer response times. See Exhibit A-70 (QAG-4).

**Q. Has land been acquired for the Lansing Service Center? If so, please identify the location of the land.**

A. Yes. Land was acquired for the Lansing Service Center in December 2020, located in Windsor Charter Township, at the southeast corner of the intersection of Canal Road and Billwood Highway, Dimondale, Michigan 48821. The Conceptual Site Plan for the New Lansing Service Center is included in Exhibit A-70 (QAG-4).

**Q. What type of operations departments will work at the new Lansing Service Center as compared to the existing Lansing Service Center?**

A. The existing Lansing Service Center houses the following operations: Customer Experience; Gas Operations; Enterprise Project Management/Environmental Services; Gas Engineering & Supply; Generation Operations & Compression; Information Technology ("IT"); Electric Operations; Operations Performance; Shared Services; and People & Culture. The Company anticipates personnel from some (not all) of these operating groups to be housed in the new Lansing Service Center.

**Q. Approximately how many employees will work at the new Lansing Service Center as compared to the existing Lansing Service Center?**

A. Over 450 employees are assigned to the existing Lansing Service Center. The Company anticipates the new Lansing Service Center will house some (not all) of these employees with some adaptation in their use of the workspace including some employees adopting a hybrid work arrangement, requiring only collaborative space and using office desk space with open seating in the facility when they are on-site to work with other personnel.

**Q. How much did the Company invest in the Lansing Service Center Project in the 2023 historical year in this case?**

A. In the 2023 historical year in this case, the Company invested $1,501,000 (gas allocation) in this project. See Exhibit A-69 (QAG-3). Expenditures in the 2023 historical year were for design engineering a municipal water main extension to the project site, pipe materials for the water main extension, and completion of an alternatives analysis for the project.

**Q. How much does the Company project to invest in the Lansing Service Center Project in the bridge period and test year in this case?**

A. As shown in Exhibit A-69 (QAG-3), the Company is projecting to invest $14,937,000 (gas allocation) in the Lansing Service Center in the 22-month bridge period and $7,199,000 (gas allocation) in the test year. As shown in Exhibit A-69 (QAG-3), page 3, the overall project is anticipated to cost $56.3 million.

**Lansing Service Center Plan Costs**

**Q. How have these projected costs been derived?**

A. A construction management firm has been engaged to develop and prepare a detailed design program and construction schedule for the Lansing Service Center project. This firm has evaluated the design program and construction schedule to develop project cost estimates.

**Q. What is the status of the Lansing Service Center Project at the time of this filing?**

A. Land acquisition and rezoning of the parcel in Dimondale has been completed. Design engineering and bidding have been completed and a contract awarded for a municipal water main extension to the project site. Materials have been ordered for the water main extension and installed. A design-build contract for construction management services has been

competitively bid and awarded. Architectural detailed design of the building is near completion. Materials are being ordered for construction of the building with construction scheduled to begin in 2025.

**Q. Please describe the Hastings Service Center Project.**

A. The Company is planning to construct a new Hastings Service Center at the existing service center location to include an adjacent property that the Company is negotiating to purchase from the adjacent landowner. This new facility will house most employees currently working at the existing service center. A portion of the employees currently working at the existing service center will have a hybrid work arrangement and will require only collaborative space and use office desk space with open seating in the facility when they are on-site to work with other personnel.

**Q. What alternatives to the construction of a new Hastings Service Center did the Company consider?**

A. The Company considered four alternatives: (1) do nothing; (2) renovate the existing Hastings Service Center; (3) demolish the existing building and construct a new building on site; and (4) construct a new facility at a new site. The options to either demolish the existing building and construct a new building on site or demolish the existing building and construct a new building at a larger site were identified as optimal depending on availability of suitable land.

**Q. Why has the Company chosen to construct a new Hastings Service Center facility?**

A. As demonstrated in Exhibit A-70 (QAG-4), a Facilities assessment of the existing Hastings Service Center produced a score of 41. As discussed above, because this score falls below a score of 48, it was targeted for replacement, and the "do nothing" option was ruled out.

For the same reason that the Lansing Service Center was targeted for replacement, including aging infrastructure, which is beyond useful life, the Hastings Service Center was determined to need replacement. The current site is fully developed and is no longer sufficient to support ongoing utility operations as the site lacks adequate space for both safe vehicle maneuvering and utility construction material storage. In addition, the existing building envelope does not comply with current energy code requirements. The Facilities organization, therefore, ruled out the renovation option for the Hastings Service Center. The existing Hastings Service Center site is located within an industrialized area with access to major roads and highways. The Company determined that the facility is currently in an optimal location to service customers (see Exhibit A-70 (QAG-4)). Therefore, with the acquisition of appropriate adjacent parcels, the Hastings Service Center has been targeted for replacement on the existing site in lieu of relocation. Other considerations supporting the decision to replace the existing site include operating cost reductions and environmental abatement.

**Q. Can you further elaborate on how these alternatives were compared?**

A. The Company originally sought to construct a new facility on the existing property. Construction of the new Hastings Service Center on the existing property was predicated on reaching an agreement with the adjacent landowner to transfer a portion of their property to Consumers Energy. This would increase the available site area for development and provide enough space for the new facility. Agreement for a property transfer with an adjacent landowner was not reached, and the properties on the west and east are fully developed. The Company then entered negotiations with the Barry County Road Commission (owner of the adjacent parcel to the south). The Barry County Road

Commission approved the Company's conceptual plan for development of this parcel. The Company now anticipates completing acquisition of the parcel in the fourth quarter of 2024 which will allow for expansion of the existing Hastings site and construction of the new facility.

**Q. What energy efficiency and waste reduction measures does the Company plan to install at the new Hastings Service Center?**

A. The proposed new Hastings Service Center facility is planned to be designed and constructed to achieve certification under the USGBC, LEED version 4 rating system.

**Q. Will this building be larger or smaller than the existing Hastings Service Center?**

A. The conceptual site plan for the new service center is shown in Exhibit A-70 (QAG-4). The original projected building area based on conceptual data assembled is larger than the existing Hastings Service Center by 11,183 square feet. The new facility is designed with a larger footprint to address multiple deficiencies at the existing facility that negatively impact gas operations including insufficient space for crew rooms, parts and material storage, welding operations, and automotive tools and repairs. Even at 23,500 square feet, however, the projected building area of the new Hastings Service Center, based on conceptual data, is smaller than many of the Company's Service Centers.

**Q. What type of operations departments will work at the new Hastings Service Center as compared to the existing Hastings Service Center?**

A. The existing Hastings Service Center houses the following operations: Customer Experience; Gas Operations; Enterprise Project Management/Environmental Services; IT (Information Technology); Electric Operations; and Shared Services. The Company anticipates the new Hastings Service Center will house many of these same operations.

**Q. Approximately how many employees will work at the new Hastings Service Center as compared to the existing Hastings Service Center?**

A. The existing Hastings Service Center houses approximately 50 employees. The Company anticipates the New Hastings Service Center will house a comparable number of employees with a portion of these employees having a hybrid work arrangement, requiring only collaborative space, and using office desk space with open seating in the facility when they are on-site to work with other personnel.

**Q. How much did the Company invest in the Hastings Service Center project in the historical year in this case?**

A. In the 2023 historical year in this case, the Company invested $4,000 (gas allocation) in this project. See Exhibit A-69 (QAG-3).

**Q. How much does the Company project to invest in the Hastings Service Center Project in the bridge period and test year in this case?**

A. As shown in Exhibit A-69 (QAG-3), the Company is projecting to invest $114,000 (gas allocation) in the Hastings Service Center in the 22-month bridge period.

**Q. How have these projected costs been derived?**

A. These projected costs represent the cost the Company anticipates to complete acquisition of the aforementioned parcel to the south in the fourth quarter of 2024. Acquisition of this parcel will allow for expansion of the existing Hastings site and construction of the new facility.

**Q. What is the status of the construction of the Hastings Service Center at the time of this filing?**

A. Conceptual plans and cost estimates for the project have been developed. The Barry County Road Commission (owner of the adjacent parcel to the south) has approved the Company's conceptual plan for development of the parcel and the Company now anticipates completing acquisition of the parcel in the fourth quarter of 2024. A Phase 1 Environmental Study has been completed and a Phase 2 Environmental Study will be conducted ahead of design and construction of the facility.

**Q. Please describe the Gas Construction Project.**

A. A complete description of the Enhanced Infrastructure Replacement Program ("EIRP") and its overall goals is outlined in the direct testimony of Company witness Kristine A. Pascarello. To support Company crews and contractor resources performing replacement of pipe and main assets as part of EIRP, the Company has identified and leased six facilities that will be used to store equipment, vehicles, and other assets used in EIRP. These six facilities will also serve as operation hubs to which EIRP Company crews and contractor resources will report for the duration of the EIRP project in those geographic areas.

**Q. Where are the facilities being used as EIRP reporting and operation hubs located?**

A. The six facilities being used as EIRP reporting and operation hubs are located as follows:

| Location | Address |
|---|---|
| Holly Gas Construction | 4100 East Baldwin Road, Grand Blanc, MI 48139 |
| Jolly Road Construction | 1500 East Jolly Road, Lansing, MI 48910 |
| Midland Gas Construction | 1850 Bay City Road, Midland, MI 48642 |
| Madison Heights Gas Construction | 111 East 12 Mile Road, Madison Heights, MI 48071 |
| Macomb Gas Construction | 27432 Groesbeck Highway, Roseville, MI 48066 |
| Saginaw Gas Construction | 2119 River Street, Saginaw, MI 48601 |

**Q. How much does the Company project to invest in the Gas Construction Project in the bridge period and test year in this case?**

A. As shown in Exhibit A-69 (QAG-3), the Company is projecting to invest $6,089,000 in the Gas Construction Project in the 22-month bridge period.

**Q. How have these projected costs been derived?**

A. Construction management firms were engaged to develop and prepare design programs and construction schedules for the Gas Construction Project, which were then used to develop project cost estimates.

**Q. What is the status of the construction of the Gas Construction Project at the time of this filing?**

A. See chart below.

**Gas Construction Project Milestones**

| Location | Procurement / Permits / Approvals | Construction / Renovation | Closeout | Current Status |
|---|---|---|---|---|
| Holly Gas Construction | October 2023 - November 2023 | November 2023 - May 2024 | July 2024 - October 2024 | In Closeout |
| Jolly Road Construction | October 2023 - December 2023 | December 2023 - October 2024 | October 2024 - December 2024 | In Construction |
| Midland Gas Construction | November 2022 - December 2022 | January 2023 - August 2023 | September 2023 - December 2023 | Complete |
| Madison Heights Gas Construction | August 2022 - October 2022 | November 2022 - April 2023 | May 2023 - August 2023 | Complete |
| Macomb Gas Construction | November 2022 - December 2022 | January 2023 - May 2023 | June 2023 - July 2023 | Complete |
| Saginaw Gas Construction | April 2023 - June 2023 | June 2023 - July 2024 | Auugust 2024 - October 2024 | In Closeout |

***Renovations***

**Q. What capital expenditures are included in the Renovations portfolio category?**

A. The Renovations portfolio category includes major modifications to the interior and/or exterior of existing facilities (e.g. adding a garage to a building). As shown in Exhibit A-69 (QAG-3), the Company is projecting to spend $11,446,000 (gas allocation) on Renovations in the 22-month bridge period and $3,280,000 (gas allocation) on Renovations in the test year.

**Q. Has the Company identified projects in the Renovations portfolio category?**

A. Yes. As shown in Exhibit A-69 (QAG-3), the Company has identified the following Renovations projects within projected bridge period and test year costs:

- Kalamazoo Service Center
- Jackson Dispatch
- Electric Vehicle ("EV") Infrastructure

**Q. Describe the Kalamazoo Service Center project.**

A. In this project, the Company is renovating the existing Kalamazoo Service Center. The Company will remediate environmental concerns, workspace concerns, and problems with aging building systems at the existing facility upon completion of this renovation. The renovations of this facility will entail adding insulation to exterior walls, installation of new exterior doors and windows, new roofing membrane and roof insulation, new interior finishes, new furnishings, new plumbing fixtures and fittings, new HVAC equipment and ductwork, and new energy efficient lighting systems.

**Q. What alternatives to the renovation of the Kalamazoo Service Center did the Company consider?**

A. The Company considered the following three alternatives: (1) do nothing; (2) renovate the existing Kalamazoo Service Center; and (3) demolish the existing building and construct a new building on site. The option to renovate was identified as optimal. See Exhibit A-70 (QAG-4).

**Q. How did the Company decide to renovate the existing service center?**

A. The Company originally planned to construct a new facility on the existing property, as discussed in Case No. U-20963. In Case No. U-20963, the Company's projected total cost

for the new Kalamazoo Service Center was $52 million. After reevaluating its original plans, the Company found additional cost savings. The Company's updated projected total cost for the new Kalamazoo Service Center is now $35 million, an approximate 33% reduction in cost (see Exhibit A-69 (QAG-3)). The Company determined that a renovation would meet its workforce needs and provide better value for customers by minimizing the scope of architectural work required to achieve needed improvements in the facility. A renovation of the existing Kalamazoo Service Center will maximize utilization of the building's existing space, while minimizing disruptions to the Company's operations. Specifically, a renovation will minimize disruptions both to areas that house the Company's operating crews and to areas where the equipment and vehicles that crews use to service customers are maintained and serviced. Other considerations supporting the decision to renovate the existing facility include the fact that the Kalamazoo Service Center is already optimally located for responding timely to the Company's customers and a renovation will yield an estimated 10% reduction in energy use (see Exhibit A-70 (QAG-4)).

**Q. Why is doing nothing not a viable option at this location?**

A. As shown in Exhibit A-70 (QAG-4), a Facilities assessment of the existing Kalamazoo Service Center produced a score of 46. Since this assessment was conducted, additional asbestos issues have been identified at this site (i.e., spray applied fireproofing, pipe wrap, floor tiles, etc.). All employees at this site had to be moved to the second floor of the building due to air quality issues rooted in the growth of mold and related asbestos concerns on the first floor. This limited space was inadequate for the Company's Electric and Gas Operations partners to operate. In addition to its environmental concerns, the existing

Kalamazoo Service Center was constructed in 1965, and its continuing use is inadequate due to aging infrastructure. Most of the existing systems throughout the facility are now over 50 years old and beyond their useful life. The space requirements of the existing workforce have changed as more personnel adopt a hybrid work arrangement requiring only collaborative workspace and transient shared office space when they are in the office working collaboratively with others. Finally, the existing Kalamazoo Service Center is optimally located for responding timely to the Company's customers (see Exhibit A-70 (QAG-4)) and, therefore, remaining at the current location best supports the Company's intent to provide timely service to its customers in the Kalamazoo area.

**Q. What energy efficiency and waste reduction measures does the Company plan to install at the renovated Kalamazoo Service Center?**

A. The renovated Kalamazoo Service Center is planned to be designed and constructed to achieve certification under the USGBC, LEED version 4 rating system.

**Q. How much did the Company invest in the Kalamazoo Service Center project during the historical year of this case?**

A. The Company invested $407,000 (gas allocation) in this project during the 2023 historical year in this case. See Exhibit A-69 (QAG-3).

**Q. How much does the Company project to invest in the Kalamazoo Service Center project in the bridge period and test year in this case?**

A. As shown in Exhibit A-69 (QAG-3), the Company is projecting to invest $10,949,000 (gas allocation) in the Kalamazoo Service Center in the 22-month bridge period and $3,080,000 (gas allocation) in the test year.

**Q. How have these projected costs been derived?**

A. A construction management firm has been engaged to develop and prepare a detailed design program and construction schedule for the Kalamazoo Service Center project. This firm has evaluated the design program and construction schedule to develop project cost estimates.

**Q. What is the status of the renovation of the Kalamazoo Service Center at the time of this filing?**

A. The Company has bid and awarded a contract for construction management services and a contract for architectural and engineering design services. Architectural and engineering design work on the project is complete and the Company has begun construction/renovation of the facility.

**Q. Is the projected size of the renovated Kalamazoo Service Center larger or smaller than the existing Kalamazoo Service Center?**

A. The size of the renovated Kalamazoo Service Center is not projected to vary significantly from the size of the existing Kalamazoo Service Center because there is no anticipated change in the overall footprint of the facility.

**Q. What type of operations departments will work at the renovated Kalamazoo Service Center as compared to the existing Kalamazoo Service Center?**

A. The existing Kalamazoo Service Center houses the following operations: Customer Experience; Gas Operations; Enterprise Project Management/Environmental Services; Information Technology (IT); Electric Operations; Shared Services; and Public Affairs. The Company anticipates personnel from some (not all) of these operating groups to be housed in the renovated Kalamazoo Service Center.

**Q. Approximately how many employees will work at the renovated Kalamazoo Service Center as compared to the existing Kalamazoo Service Center?**

A. Approximately 250 employees are assigned to the existing Kalamazoo Service Center. The Company anticipates the renovated Kalamazoo Service Center will house the majority (not all) of these employees with some employees adopting a hybrid work arrangement and requiring only collaborative space and using office desk space with open seating in the facility when they are on-site to work with other personnel.

**Q. Please describe the Jackson Dispatch project.**

A. The Company's Gas Dispatch and Electric Dispatch Centers in Jackson shared a common workspace. This shared space was also utilized by temporary storm response personnel during storm response events which resulted in confusion and miscommunication within and among the dispatch groups and storm response personnel. Company crews, for instance, had reported difficulty communicating with dispatch personnel during storms because of background noise in the Dispatch Center which introduced an unnecessary risk of human performance error. Additionally, the existing HVAC system was unable to support the cooling load of personnel and equipment working in this space, especially during storm response events. Renovation of the Jackson Service Center second floor will provide a new space to house the Gas Dispatch center while leaving the remaining space for dedicated use by Electric Dispatch and storm event personnel. The Electric Dispatch and area for storm response personnel received new permanent supplemental cooling to meet the increased demand during full occupancy and storm response events. Modifications have been made to the existing HVAC system to better serve the renovated Gas Dispatch area.

**Q. What alternatives to the renovations of this space did the Company consider?**

A. The Company considered the following three alternatives: (1) do nothing; (2) subdivide existing space; and (3) reconfigure space for Gas Dispatch and provide permanent supplemental cooling for the Electric Dispatch area and area for storm response personnel. The third option was identified as optimal.

**Q. Why did the Company choose to renovate these spaces in the Jackson Service Center?**

A. As discussed above, the space shared by the Company's Gas Dispatch and Electric Dispatch centers in Jackson was inadequate for two primary reasons. First, the space as formerly configured was suboptimal as the area often became congested (especially during storm response events) resulting in confusion and miscommunication within and among gas and electric dispatch groups and storm response personnel. Second, occupant load within the space exceeded available HVAC system cooling capacity resulting in overheating and severe discomfort among Dispatch personnel. The risk of confusion and miscommunication between Gas and Electric Dispatch personnel and Company crews represented an unnecessary safety risk to both Company crews and the public. These facts ruled out the "do nothing" option. Subdividing the shared space coupled with the use of temporary cooling equipment was determined to be insufficient to properly condition the space and represented a long-term cost. The Company, therefore, opted to reconfigure the space and provide permanent supplemental cooling to meet the variable cooling load in the space.

**Q. What benefits will this renovation provide for customers?**

A. Renovating this space shared by the Company's Electric and Gas Dispatch groups will improve communication between Gas Dispatch personnel and Company crews resulting in

improved gas leak response. Improved communication will reduce the risk of safety incidents for both Company Gas crews and the public.

**Q. How much does the Company project to invest in the Jackson Dispatch project in the bridge period and test year in this case?**

A. As shown in Exhibit A-69 (QAG-3), the Company is projecting to invest $156,000 (gas allocation) in the Jackson Dispatch Project in the 22-month bridge period.

**Q. What is the status of the renovation of the Jackson Dispatch area at the time of this filing?**

A. The Jackson Dispatch Project is complete.

**Q. Has the Company invested capital in the Jackson Dispatch renovation thus far?**

A. Yes. In the 2023 historical year of this case, the Company invested $302,000 (gas allocation) in the project.

**Q. Please describe the Electric Vehicle Charging Infrastructure project. What are its overall goals?**

A. As outlined in the direct testimony of Company witness Corey E. Ballinger, the Company has a strategy to electrify portions of its vehicle fleet by purchasing EVs for Company use. As Company witness Ballinger discussed, the Company is currently acquiring EVs. To ensure these EVs are available for Company crews to use in serving customers, the Company must construct adequate charging infrastructure at sites where these vehicles will be maintained.

**Q. At which Company sites will EVs purchased in the bridge period and the test year be maintained?**

A. The Company sites at which EVs purchased in the bridge period and test year will be maintained is outlined in the direct testimony of Company witness Ballinger.

**Q. How much capital is the Company projecting to invest in the Electric Vehicle Charging Infrastructure project in the bridge period and test year in this case and for what purpose?**

A. As shown in Exhibit A-69 (QAG-3), the Company is projecting to invest $341,000 (gas allocation) in the Electric Vehicle Charging Infrastructure project in the bridge period and $199,000 (gas allocation) in the test year. The purpose of this investment is to provide the electric infrastructure upgrades and charging station installations required to support EVs purchased in the bridge period and test year as outlined in the direct testimony of Company witness Ballinger.

**Q. How were these costs determined?**

A. Cost estimates were developed for electric infrastructure upgrades and charging station installations required to support EVs purchased in the bridge period and test year utilizing historical cost data from similar projects.

**O&M Spending Overview**

**Q. What is included in the projected O&M expenses for Gas Operations Support?**

A. The Company is projecting to spend $9,525,000 in Gas Operations Support for the test year. This spending is allocated between Facilities, Real Estate, and Supply Chain. Total Gas Operations Support O&M expenses included in Exhibit A-68 (QAG-2) for the test

year were established at a level not to exceed total Gas Operations Support O&M expenses for the historical year in this case.

**Q. What O&M expenses are included in "Facilities," line 1 in Exhibit A-68 (QAG-2)?**

A. Facilities work includes items such as maintenance and repair of HVAC systems, miscellaneous building repairs, yard maintenance and snow removal, and daily cleaning or other major scheduled cleaning projects such as windows and carpeting.

**Q. What O&M expenses are included in "Real Estate," line 2 in Exhibit A-68 (QAG-2)?**

A. Real estate services includes a variety of real estate asset management functions to ensure system integrity and safeguarding of the public. This includes management of all land-related uses of easements and rights of way, including encroachments, third-party requests for use of Company property, landowner requests for modification of easement rights or approval of permission to construct within an easement, as well as management of all corporate facility leases. The group also responds to all requests to sell property or grant easements, leases, or licenses to third parties. Included in real estate services is the records management function that is responsible for maintenance of a land inventory and Geographic Information System mapping for property ownership and rights of way.

**Q. What O&M expenses are included in "Supply Chain," line 3 in Exhibit A-68 (QAG-2)?**

A. Supply Chain assists with vendor and contractor management, purchasing of materials and services, document reproduction, and internal mail distribution.

**Q. Does this conclude your direct testimony in this proceeding?**

A. Yes.

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

| | | |
|---|---|---|
| In the matter of the application of<br>**CONSUMERS ENERGY COMPANY**<br>for authority to increase its rates for the<br>distribution of natural gas and for other relief. | )<br>)<br>)<br>)<br>) | Case No. U-21806 |

**DIRECT TESTIMONY**

**OF**

**COREY E. BALLINGER**

**ON BEHALF OF**

**CONSUMERS ENERGY COMPANY**

December 2024

**Q. Please state your name and business address.**

A. My name is Corey E. Ballinger, and my business address is One Energy Plaza, Jackson, Michigan 49201.

**Q. By whom are you employed and in what capacity?**

A. I am employed by Consumers Energy Company ("Consumers Energy" or the "Company") as Fleet Acquisition & Asset Disposition Manager.

**Q. What is your formal educational experience?**

A. I have a High School Diploma and attended Jackson College in Jackson, Michigan.

**Q. What are your responsibilities as Fleet Acquisition & Asset Disposition Manager?**

A. I provide oversight to Fleet Acquisition supporting the Company's current and long-term capital replacement strategy, vehicle disposition, licensing, rentals, and internal electric vehicle ("EV") strategy. In addition, I provide oversight to the Company's Investment Recovery Center ("IRC") function, which handles the disposition of surplus Company assets.

**Q. Would you please describe your previous work experience?**

A. In 1999, I started my career at American Tooling Center in Grass Lake, Michigan as a Tool and Die Apprentice. American Tooling Center designs and builds large line dies for all major manufacturers in the automotive industry. In 2001, I was hired by Consumers Energy as an Operations Assistant in the Company's mailroom. In 2002, I accepted an Administrative Assistant position in Fleet Acquisition. In this role, I assisted with writing fleet specifications and managed the internal rental and licensing programs. In 2005, I was promoted to Fleet Field Leader in the Southern Zone. The Fleet Field Leader position consisted of oversight of all preventative maintenance and repairs to Consumers Energy's

Fleet within the zone. My role as a Fleet Field Leader continued to expand across multiple zones until I had oversight of 14 locations, 2 schedulers, and 23 mechanics. In 2013, I accepted the position of Sr. Technical Analyst II in Fleet Acquisition. In this role, I was responsible for the design and purchase of Consumers Energy vehicles, trailers, and equipment. I created Requests for Proposals and provided oversight for the annual Fleet Purchase Plan for Gas Operations. In 2022, I was promoted to Fleet Acquisition and Asset Disposition Manager.

**Q. Have you previously been a witness, or supported witnesses, in any proceedings before the Michigan Public Service Commission ("MPSC" or the "Commission")?**

A. Yes. I was the witness for the most recent Electric Rate Case No. U-21585 and I provided support to the fleet witness in Electric Rate Case Nos. U-21224 and U-21389, as well as the two most recent natural gas rate cases, Case Nos. U-21308 and U-21490.

**Q. What is the purpose of your direct testimony in this proceeding?**

A. The purpose of my direct testimony is to support the Company's costs related to the gas business portion of Fleet services. To that end, I will:

I. Describe the Company's Fleet and how it is managed through Fleet Services;

II. Explain the Company's Fleet Replacement Planning Process;

III. Explain the Company's Fleet Electrification Strategy; and

IV. Sponsor the Company's Fleet capital spending projections.

**Q. Are you sponsoring any exhibits with your direct testimony?**

A. Yes. I am sponsoring the following exhibits:

| | | |
|---|---|---|
| Exhibit A-12 (CEB-1) | Schedule B-5.2 | Summary of Actual & Projected Capital Expenditures Fleet Services; |
| Exhibit A-27 (CEB-2) | | Fleet Responsibility Costs; |

| | |
|---|---|
| Exhibit A-28 (CEB-3) | Detailed List of Projected Gas Capital Expenditures Fleet Services for the Years 2023, 2024, 2025 and test year 12 months ending October 31, 2026; and |
| Exhibit A-29 (CEB-4) | Summary of Fleet Tooling Actual & Projected Capital Expenditures. |

**Q. Were these exhibits prepared by you or under your direction and supervision?**

A. Yes.

**Q. Please briefly describe the exhibits that you are sponsoring.**

A. I am sponsoring Exhibit A-12 (CEB-1), Schedule B-5.2, which is a Summary of Actual and Projected Capital Expenditures for Fleet Services for the calendar year 2023, bridge period (22 months ending October 31, 2025), and the projected test year 12 months ending October 31, 2026; Exhibit A-27 (CEB-2), which provides details of the Company's fleet responsibility dollars; Exhibit A-28 (CEB-3), which provides details of the Company's Fleet acquisitions in the historical year 2023, bridge period (22 months ending October 31, 2025), and the projected test year 12 months ending October 31, 2026; and Exhibit A-29 (CEB-4) which is a Summary of Actual and Projected Fleet Tool Capital Expenditures for the historical year 2023, bridge period (22 months ending October 31, 2025), and the projected test year 12 months ending October 31, 2026.

## I. FLEET SERVICES FUNCTION AND RESPONSIBILITIES

**Q. What functions compose the Fleet Services organization?**

A. The Fleet Services organization consists of three departments which collaboratively work together to provide value to Gas Operations in serving customers. The three departments include Fleet Maintenance Operations, Fleet Acquisition, and Shared Services Governance Performance and Technology.

**Q. Are you addressing all support organizations related to Gas Operations Support in your direct testimony and exhibits?**

A. No. I will be addressing Fleet Services only. Facilities will be addressed in the direct testimony of Company witness Quentin A. Guinn.

**Q. Please explain the responsibilities of Fleet Maintenance Operations.**

A. Fleet Maintenance Operations is responsible for maintaining a safe, cost effective, and reliable fleet. This is accomplished through preventative maintenance, regulatory inspections, parts inventory management, and maintenance scheduling across 36 garage locations with approximately 110 mechanics. Maintenance Operations also oversees mechanic contractor crews for preventative maintenance and repairs performed in the field.

**Q. Please explain the responsibilities of Fleet Acquisition.**

A. Fleet Acquisition executes all functions related to the acquisition and disposition of Company-owned and rented vehicles and related equipment. This includes management of the Fleet capital purchase plan, vehicle specification design, licensing/title, registration, and asset retirement.

**Q. Please explain the responsibilities of Shared Services Governance Performance and Technology department.**

A. Governance Performance and Technology provides fleet with support of data integrity, Telematics data management, departmental metric visual management, process automation, oversight of waste elimination initiatives, and evaluates benchmarking and data analysis provided to the Company. This team is also responsible for meeting all regulatory and compliance requirements with the American National Standards Institute, Department of Transportation, Michigan Motor Vehicle Code, and Federal Motor Carrier

Safety Administration. Additional responsibilities include Fleet Operations Policies and Procedures, regulatory and technical support, and tooling for fleet mechanics and the Company's EV strategy. The department also provides oversight for quality inspection audits and safety requirements related to regulatory compliance.

**Q. Please explain the Company's overall fleet structure.**

A. The Company's fleet includes approximately 7,207 owned, leased, and rented units across 36 locations. These units include light duty vehicles (approximately 2,800 units), medium and heavy-duty trucks (approximately 1,500 units), various types of equipment (approximately 1,400 units), and trailers (approximately 1,900 units). Internally, the Company categorizes its fleet into several specifications ("spec(s)"), each of which is a given type, model, and description of a vehicle. Each spec has a defined intended use, acquisition cost, operating cost, and expected life in years and mileage.

**Q. How is the Company's fleet divided between the electric and natural gas businesses?**

A. The Company divides its fleet between the electric and natural gas businesses by determining which business unit at a given location is using each particular vehicle. The needs of the business require the deployment of dedicated teams to safely complete work utilizing specific tools and processes – this extends to the vehicle supporting said work. These vehicles are ordered and upfitted to support specific work and are, therefore, specialized for the work they perform; however, the Company does seek ways that units can be shared across the business when possible. The fleet requirements for the location will vary based on the service provided to the customer (electric, gas, or both), crew counts, and region. Additionally, some Company fleet units serve both electric and gas functions and are referred to as "common" units, which are utilized by support organizations, such

as Facilities, Fleet, and Supply Chain. Overall, the Company's fleet is 40% electric, 50% gas, and 10% common by number of vehicles.

**Q. What is the purpose of Fleet Services as it relates to the Company's gas business?**

A. Specific to the Company's gas business, Fleet Services' purpose is to provide vehicles and equipment that enable Gas Operations to serve customers with safe, reliable, and affordable gas service. This is accomplished by ensuring that the Company's Fleet assets are available to execute the work plan and respond to emergencies in the most efficient, cost-effective, and safe manner when required.

**Q. Does the Company's fleet incur both capital and operating and maintenance ("O&M") costs?**

A. The Company makes direct capital investments into its fleet as provided in Exhibit A-12 (CEB-1), Schedule B-5.2, and Exhibit A-27 (CEB-2). The Company also incurs other costs related to its fleet that are treated as "fleet responsibility" dollars, which in this case are presented in Exhibit A-27 (CEB-2).

**Q. What are fleet responsibility dollars?**

A. In addition to direct capital expenditures for fleet vehicles, tools, and other equipment, the Company also incurs other costs related to its fleet that are treated as "fleet responsibility" dollars. The Company does not have specific Fleet O&M expenses.

Fleet operating costs are reported in responsibility dollars. Each fleet unit has defined work assignments that determine which functional areas are allocated the associated responsibility dollars for the unit. Fleet responsibility costs are allocated to both capital and O&M expenses based on the work assignment performed.

**Q. Please explain how fleet responsibility dollars are allocated to both capital and O&M.**

A. The process for allocating fleet responsibility dollars is a multi-step process. The first step in the process is that costs associated with each fleet vehicle or piece of equipment are charged to an internal order. Each fleet vehicle/equipment has its own internal order that collects costs like fuel and maintenance, which is assigned to a department/responsibility area.

The next step is that the costs from the internal orders are moved to separate fleet clearing accounts for each department/responsibility area. The final step in the process is the allocation of the costs from the fleet clearing accounts. The costs in each clearing account are allocated to work orders or cost centers based on the labor charges for that department/responsibility area. Additionally, the fleet costs to be allocated are separated between labor and non-labor fleet loading.

## II. FLEET REPLACEMENT PLANNING PROCESS

**Q. What is the Company's overall Fleet Replacement Planning Process as it is being presented in this case?**

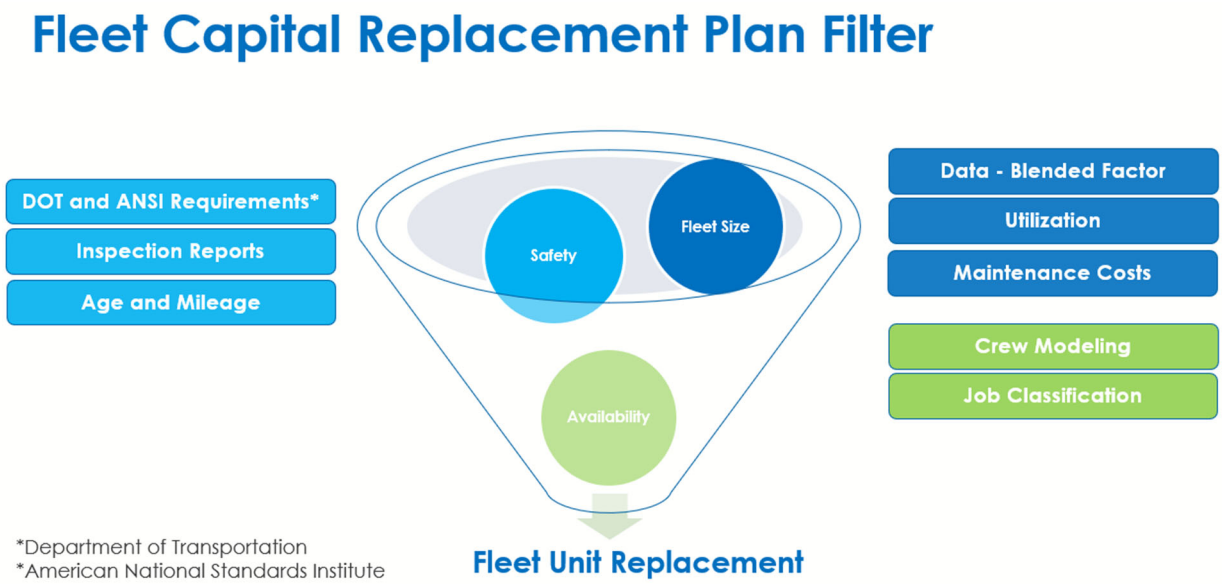
A. As previously presented in Electric Rate Case Nos. U-20963, U-21224, U-21389, and U-21585, and Gas Rate Case Nos. U-21148, U-21308, and U-21490, the Company develops its Fleet Vehicle Capital Replacement Plan using the Fleet Replacement Planning Process, which is a process that incorporates three phases. In the first phase, the Company identifies vehicles that are at or near the end of their expected life and are eligible for replacement, using a tool called the Blended Factor that is described in more detail below. Next, in the second phase, the list of vehicles identified by Blended Factor Analysis for potential replacement is further developed by certain data tools, described below,

particularly by fleet cost data, followed by crewing data, and, lastly, fleet utilization data. In this second phase, the Company's fleet leadership also works with Operations leadership and personnel in the field, which includes operators and mechanics, to identify which specific units should be replaced, incorporating qualitative inputs like maintenance reports and local area work needs. This second phase allows for further evaluation of the vehicles identified in the first phase to better determine which vehicles should be replaced. Thereafter, in the third phase, the list of vehicles identified for retirement is finalized based on the evaluations performed in the first two phases, and the ordering process begins. If an existing contract is already in place, orders are placed immediately with the manufacturer or vendor. For vehicles not covered by an existing contract, detailed specifications are written and requests for proposals are sent out to vendors (including minority-owned and Michigan-based businesses whenever possible). Once bids are received, they are evaluated and awarded based on cost, product support, and quality.

**Q. Please further explain how the Company establishes its Fleet Replacement Planning Process.**

A. The Company strives to replace assets at the optimal moment in the vehicle's service life by incorporating several factors in the decision-making process, particularly within phases 1 and 2. In doing so, the Company uses data gathered for each spec that is documented, monitored, and corroborated with detailed in-person inspections. Data is generated by the fleet through Telematics, including utilization rates, fleet age, and detailed inspections as a basis for determining future fleet purchases of specific capability and utility. The Company's process for compiling and analyzing qualitative and quantitative

inputs to develop its Fleet Vehicle Capital Replacement Plan is illustrated by the "filter" shown below.




**Q. Please explain how the Fleet Capital Replacement Plan Filter works.**

A. When the Company goes through its Fleet Replacement Planning Process, specifically within phases 1 and 2, certain data – such as the Blended Factor, utilization, operating cost, and crewing needs – is analyzed to determine if a given vehicle needs to be replaced. During the Fleet Replacement Planning Process, other qualitative inputs like vehicle inspection reports and the assessments of field employees provide further insight on replacement needs. The result of this process, specifically following the first and second phase, is a list of fleet units to be replaced.

**Q. Can you describe, in further detail, the Blended Factor used in phase 1 and the Fleet Cost Tool, Crewing Model Tool, and Fleet Utilization Tool used in phase 2?**

A. Yes. These are each described in the following sections.

**A. Blended Factor**

**Q. Please further explain the Blended Factor.**

A. The first step in the Company's process for establishing its Fleet Vehicle Capital Replacement Plan is informed by the Blended Factor. As previously mentioned, the Blended Factor takes age, usage, and mileage into consideration and establishes a replacement priority for units that are more economical to replace than continuing to maintain. The Blended Factor for any vehicle is calculated as shown in the illustrative example below:

**Blended Factor Calculation**

$$\text{Blended Factor Rating} = \left(\frac{[\text{Age Factor} + \text{Usage Factor}]}{2}\right)$$

$$\text{Age Factor} = \left(\frac{\text{Actual Age in Months}}{\text{Expected Life in Months}}\right) - 1$$

Example: $\left(\frac{102}{84}\right) - 1 = .21$

$$\text{Usage Factor} = \left(\frac{\text{Estimated Mileage}}{\text{Expected Life Mileage}}\right) - 1$$

Example: $\left(\frac{223{,}180}{150{,}000}\right) - 1 = .488$

**Blended Factor Example:** $\left(\frac{[.21 + .488]}{2}\right) = .349$

Equipment and engine operation hour calculation: 1 hour = 25 miles

For equipment that does not have mileage (no odometer), the Blended Factor calculates usage from the engine hours. For medium and heavy-duty vehicles, the Blended Factor calculation also uses total engine hours, assuming that one hour of engine operation is equivalent to 25 miles of travel. Using this calculation, a Blended Factor result greater than 0.00% indicates that a vehicle is at or past its expected life and is therefore eligible for consideration for replacement. This indicator does not mean that a vehicle with a result

greater than 0.00% is automatically selected for replacement; it is instead a *starting point* each year for the Company to use as a foundation in the selection of vehicles for replacement.

**Q. Why is it important for the Company to consider the expected life in months and expected life in mileage for each of the respective specs?**

A. The Blended Factor formula incorporates two key indicators of end of its expected life: (1) how old a vehicle is and (2) either how many miles it has traveled or total hours of operation. Expected Life in Months considers manufacturer inputs, reliability, operating conditions, and operating cost to determine the duration the Company expects a vehicle to operate safely and cost effectively. Expected life in mileage or hours is also based on similar considerations as an indicator of wear and tear. The Company makes these evaluations to set a foundational benchmark to assess potentially replaceable vehicles. The fleet has a diverse range of specs for specific operational needs, and not all specs have the same expected life. Even within the same spec, individual units can vary in condition depending on utilization and wear. Managing each spec to its appropriate expected life ensures that the Company always has the right type of vehicle available to serve the needs of customers in the safest, most reliable, and most efficient manner possible, while minimizing costs.

**Q. Why is the use of the Blended Factor appropriate?**

A. The Blended Factor is an internal data-based algorithm that incorporates unit age, utilization (in mileage or hours), and expected life, allowing the Company to prioritize, plan, and target specific vehicle(s) for replacement. As a key feature of the *first phase* of the replacement process, the vehicles denoted by the Blended Factor to be approaching the

end of their expected life provide the basis for planning phases ahead. This process is critical to assure that the Company can order a timely unit replacement, especially given the supply chain challenges that have emerged in the last three years. While there has been some improvement in the expected delivery dates for some products, planning around potential delivery delays and availability is still a concern as demand for new medium and heavy-duty equipment remains high. By using the Blended Factor, the Company can strategize future spending for replacement units for specific years by consulting with suppliers on current and future availability, thereby preparing the Company to order units given current lead times to receive a unit once an order is placed.

**Q. What conclusions do you draw regarding the Blended Factor?**

A. The Blended Factor provides an objective standard that uses clear internal fleet data to identify units for potential replacement and adds a level of predictability regarding which units will need to be replaced to improve the cost-effectiveness of the replacement process. Based on the above Blended Factor calculations, it is indicated that out of 7,207 units currently in the fleet, there are approximately 2,794 units greater than 0.00%.

### B. Fleet Cost Tool

**Q. Please explain the Company's fleet cost tool.**

A. As part of the second phase in its Fleet Replacement Planning Process, the Company is utilizing the fleet cost tool, incorporating data analytical tools to support near- and long-term cost-effective vehicle purchase plans. These analytical tools include tracking vehicles by spec and the average age of each spec, fleet O&M costs, and geographical location. Additionally, the fleet cost tool provides at-a-glance total and average per-vehicle operating costs for each spec from various perspectives, including operating costs per mile,

by age, and by specific vehicle. These tools provide data indicating vehicle count and average age, broken out by spec. The purpose of these tools is to provide overall cost status summaries of the fleet, as well as a platform to perform more detailed cost analyses of individual vehicles. The following are descriptions of several tools the Company has developed.

**Q. What are these tools that the Company has developed to support fleet cost analyses?**

A. For an overall summarization of fleet age and operating costs, the Company has developed "Unit Age and Operating Cost" and "Unit Count and Average Age" tools to provide information regarding fleet operating costs correlated with age. Operating costs include maintenance, fuel, and repairs. This information can be filtered by vehicle year and spec and can assist in identifying trends that will enable cost forecasting to support future purchasing decisions.

**Q. What are additional analytical tools related to fleet cost?**

A. The Spec Detail Information Analysis identifies equipment count by spec and is designed to highlight yearly fleet growth by spec, which helps identify trends and how the fleet's makeup and size changes over time.

**Q. Are there any other analytical tools that are part of the fleet cost tool?**

A. The Age and Cost Spec Detail Analysis is designed to provide detailed cost information for a specific unit, including total operating cost, as well as average costs over time for specific specs. In this analysis, the Company evaluates equipment count, total operating cost, average unit operating cost, median unit operating cost, and average unit age. Finally, a Location Summary Analysis displays a particular territory, city, spec, equipment count, and total operating cost for vehicles distributed throughout the Company's service area.

Equipment Count by location is displayed on a map with circle size indicating high/low equipment counts and color indicating zone. Average Unit Age and Total Operating Costs are summarized in cards at the top of the page. This page allows the user to filter on Year, Usage Indicator, Rental Status, and Spec. The purpose of this tool is to allow the user to use the filters to summarize equipment count, cost, and age by location.

**Q. Why are these fleet cost analytical tools appropriate for the Company to use?**

A. Using the Company's own data, the information these tools provide is used to help the Company plan the cost-efficient replacement and acquisition of new vehicles. The Fleet Cost Tool data provides information from several perspectives that helps narrow the pool of vehicles identified by the Blended Factor for replacement. For example, the Blended Factor may identify many units within any given spec that are at or near the end of their expected life, but a further examination using this tool can help inform how the unit is performing in relation to other identical spec vehicles in the fleet from a cost perspective. If the unit has become uneconomical to operate compared to other vehicles in the same spec, it may be best to replace that vehicle for a more cost-effective solution sooner rather than later. Conversely, a vehicle that has reached the Blended Factor end of expected life may still have years of economical service possible based on operating cost reported by these tools. This fleet cost tool also allows the Company's fleet management to understand how fleet costs have changed year-over-year, including the ability to examine costs of specific units to help inform if they are good candidates for replacement. The tool is intended to provide an overview of past fleet metrics, and helps to identify relationships between unit age, mileage, and operating costs. It also shows fleet age by spec which can be helpful when multiple units of the same spec were purchased in the same year. This is

important information to consider when prioritizing the most appropriate vehicles to replace at any given point for the benefit of customers.

**Q. What has the Company learned to date from using its fleet cost tool?**

A. The fleet cost tool has allowed the Company to make informed decisions while reviewing units identified for replacement. This tool provides the Company with an at-a-glance total of overall costs of a particular unit. As the fleet team strategizes how and where to replace vehicles, the cost tool assists in framing how to best benefit the customer in the decision-making process.

As noted, the Blended Factor calculation is a starting point in the decision-making process, with the expectation that the list can be modified as further analysis proceeds. The cost tool facilitates a review of repairs and improvement costs associated for each vehicle that can extend its service life. For example, feedback sought and received from field leaders on the overall condition and serviceability of a truck can show that it should be kept in service instead of being replaced. This includes investments like engine or transmission rebuilds, or body rust repairs. The fleet cost tool quickly identifies which units require closer scrutiny when making purchasing decisions. This benefits the customer in that the Company gets as much service life out of units as is economically prudent.

### C. Crewing Model Tool

**Q. Please explain the Company's crewing model and crewing model tool.**

A. As part of the second phase of its Fleet Replacement Planning Process, the Company's crewing model is used to calculate how many vehicles are needed based on the size of the workforce. This model incorporates all gas department vehicles and details about which employees are assigned to operate these vehicles. The gas departments include Gas

Service, Gas Transmission, Gas Compression, Gas Construction, and Gas Distribution. These departments operate the following types of vehicles: dump trucks, digger derricks, vans, pickup trucks, and other support vehicles. The crewing model tool illustrates how many vehicles are needed and how many vehicles are available, giving visibility to gaps.

**Q. What information does the tool show?**

A. The tool lists Company locations and, for each location, shows the number of units at that location by workgroup, breaking down the number of employees and the number of different types of units located there. Based on this information, the tool provides the gap between the actual number of vehicles at the location and the number of vehicles needed.

**Q. How was this crewing model developed?**

A. The Company's Gas Operations Department's workforce size and crewing influences the number and types of vehicles needed to serve customers. Crewing is determined by the work required and influenced by safety and policy procedures related to the work performed. In the crewing model, the Company uses standard crewing of the following truck-to-employee ratios:

- Gas crewing consists of one Gas Line Worker ("GLW") and/or one Trenching Machine Operator ("TMO") to make one crew. Each crew is assigned a Gas Service Truck (spec 44) and a support vehicle. The support vehicle could be a dump truck or a pickup. The crewing model calculates vehicle needs according to the following ratios:

| **Vehicle Type** | **Model Ratio** |
|---|---|
| Gas Service Truck (spec 44) | 1:1 TMO to Gas Service Truck |
| Digging Equipment | 1:1 GLW/TMO to Digging Equipment |
| Pickup | 1:1 GLW to Support Vehicle |
| Fillet Welder (Spec 28) | 1:1 GLW to Fillet Welder |

- Employees in Gas Meter Operations, Customer and Field Services, usually operate as single workers, rather than in a crew, meaning they have a 1:1 vehicle ratio.

**Q. Why is this crewing model appropriate for the Company to use?**

A. The crewing model is based on industry best practices and Occupational Safety and Health Administration ("OSHA") requirements.[1] To provide a safe, reliable, and cost-effective fleet, it is important that the Company's fleet be adequate in size to complete the established work plan, work safely, and adhere to OSHA requirements.

**Q. What conclusions can you draw from the data shown in the crewing model tool?**

A. The model shows that the quantity of production units (gas service trucks, support vehicles, welders, and digging equipment) currently in the Company's fleet will continue to be evaluated based on established work plans and employees needed to perform the work (more information on how utilization data is calculated is provided in the next section of this testimony). The model can help identify surplus or deficiency of assets in each specific area and units that are down for repairs or regular maintenance. This visibility allows the Company to reallocate surplus assets to areas with deficiencies to ensure each area is adequately supplied based on the model. Backup vehicles must be ready to meet the needs of the crews as daily schedules develop, meaning that some additional vehicles may be needed on short notice. The Crewing Model allows for backup vehicle availability for such circumstances to reduce the risk of gaps between crews and vehicles needed in the field.

The crewing model assumes the Company will onboard new workers or add replacement workers consistently and in a timely manner as work plans develop to drive the need for workers and as attrition rates affect the workforce. However, the Company

[1] 1926.960 - Working on or near exposed energized parts. | Occupational Safety and Health Administration (osha.gov): https://www.osha.gov/laws-regs/regulations/standardnumber/1926/1926.960

does not always receive new vehicles at the same time new workers are onboarded. For this reason, it is possible that new vehicles will be received and paid for before workers are ready to use them, but those vehicles *will* be put into use once the planned hiring is complete. Utilization rates for vehicles may at times reflect this reality.

**Q. What has the Company learned to date from using its Crewing Model?**

A. The Crewing Model offers the ability to find gaps in available units, and much like a checklist, allows the Company to proactively prepare for any emerging vehicle needs based on how new projects and employees are planned or deployed. In this manner, the Crewing Model complements the other fleet tools the Company is developing by ensuring that units are allocated as effectively as possible before and after any new units are purchased. The customer benefits from this because the Company is constantly working to keep its fleet right sized, with as little redundancies as possible.

### D. Fleet Utilization Tool

**Q. Please explain how the Company captures utilization data for its fleet.**

A. All vehicles use a Telematics device that is directly wired to that asset's onboard computer or switching. Each installed Telematic device communicates, via cellular signal in real time, information about the asset status including the unit's exact Global Positioning System ("GPS") location, date, time, mileage driven, and hours in operation. A vehicle is considered in use for any given day when it has traveled five or more (5+) miles at any time or equipment that is in operation for 30 or more (30+) minutes per day. This captured data is then uploaded and compiled on a nightly basis into one tool that can then be used to run reports as needed to manage the operation. This data is compiled into a fleet

utilization tool that can provide fleet use by zone, by vehicle type, or department and is used as part of the second phase in the Fleet Replacement Planning Process.

**Q. How was this data process developed?**

A. The electronic information captured by the Telematics system documents industry standard data points that are used to log key vehicle information. Since 1996, every vehicle manufactured in the United States has an On-Board Diagnostic ("OBD") port/interface that can easily be made accessible to Telematics systems and their associated electronic data gathering capabilities. The OBD system provides access to a vehicle's Electronic Control Unit, the main computer that controls vehicle engine, transmission, and other key vehicle functions. By connecting directly to the OBD of each vehicle, the Telematics system is able to collect the real-time information required to inform the Company to log the key data points required to document utilization.

**Q. How is the Company's utilization data tied to the crewing model?**

A. As explained in the crewing model section, vehicles are assigned in response to the requirements of the daily work plan and the employees needed to complete the work. Some types of vehicles, like bucket trucks, are used frequently for common field operations, whereas there are other types of vehicles that are highly specialized and designed for specific tasks that are not always required on a given day/night to serve customers but are no less crucial to properly service customers throughout the state. The Company's utilization data also accounts for the downtime that equipment must undergo when receiving inspections, maintenance and repair, or other ancillary equipment upgrades, and for the fact that some equipment must be available for on-call assignments and off-hour assignments.

**Q. Why is this approach to utilization data appropriate for the Company to use?**

A. By capturing real-time telematic data from each asset and compiling it in one dataset, the Company obtains the required raw data to detail the exact frequency, duration, and overall use of each asset, and this data is then searchable for reporting utilization rate purposes. Utilization data can illustrate where units may be underutilized. The customer benefits from this approach because the Company ensures that all vehicles and assets are tracked, monitored for maintenance and safety, and allows for the optimal cost-benefit relationship and return on investment for its fleet. This approach supports the analysis of what assets the Company needs to purchase to be sure that it is replacing vehicles at the end of their lifecycles, and to be sure that the Company is serving customers with safe, capable, and effective equipment.

**Q. What conclusions do you draw from the Company's fleet utilization data?**

A. The Company's utilization rate data informs us that a continual review of fleet equipment for under-utilized vehicles, what areas of the business they serve, and how that may impact the Company's ability to serve its customers, will be on an ongoing analysis. It is a key tool in determining why and where vehicles may be down (or showing lower utilization rates). For example, vehicles that are down for repair or waiting for parts are different from vehicles that are available but are not being used to serve customers when evaluating utilization rates. The Company analyzes its fleet utilization to determine if there are any redundancies that can be dispositioned in the future, such as through attrition and reallocating to raise utilization to more optimal levels.

**E. Benefits**

**Q. Please summarize the Company's Fleet Replacement Planning Process.**

A. The Company's fleet consists of 7,207 units of varying specs utilized for specific tasks to serve customers, divided between the electric and gas sides of the business. Assets referred to as "common units" are utilized by various other departments within the Company to support business operations. The Company employs a Fleet Replacement Planning Process (Replacement Filter, Blended Factor, Cost Data, Utilization Data and Crewing Models) to determine, in the most cost-effective and efficient manner, which units to replace. The Blended Factor identifies a pool of assets to consider replacing based on the mileage and age of each asset. Fleet cost data helps refine the initial group of eligible vehicles by helping to identify units that have become more costly than their value, or inefficient to maintain in the fleet. By applying crew modeling and utilization analysis, the Company checks to ensure that crew sizes support the potential number of vehicles replaced or added and confirms that replacement assets are appropriate based on usage rates. The customers benefit from this overall process because the systematic efforts noted above attempt to replace and/or add fleet assets at the most beneficial time possible. Each step in the process is designed to specifically identify which assets to add or replace, and the rationale and timing.

**Q. What are the benefits of the Fleet Cost Tool for customers?**

A. The tool helps the Company make decisions about which units should be replaced or kept by illustrating when the cost of maintaining the units outweighs the cost of a new unit, or investments made in units to keep them in service, which ultimately supports decisions made in the Company's Fleet Vehicle Capital Replacement Plan. The tool allows for

visibility in significant investments such as a new engine or transmission in a vehicle that could extend its service life. The customer benefits from this analysis because the Company is using fleet dollars in the most economical way possible.

**Q. What are the benefits of the Crewing Model for customers?**

A. Having the ability to tie the workforce to the right vehicle by location enables the Company to have visibility to align assets with the workplan by department and location. As the Company strives to be a good steward of the fleet, the model helps validate if additional units are needed to meet the Company's workplan or, alternatively, if the Company has any surplus units that can be redeployed or retired. Absent this, the Company may end up lacking the appropriate vehicles to complete work for the customers' benefit.

**Q. What benefits does fleet utilization data provide for customers?**

A. Peak utilization of all vehicles is a balance between fully utilizing purchased assets and having the right asset in place and ready when needed at a moment's notice when responding to outages, new business, or construction situations. Fleet assets other than specialized equipment that are underutilized are not providing the maximum benefit to the customer. As good stewards of its fleet, the Company must provide the most cost-effective methods to assure that the fleet is a safe and effective part of the service it provides.

The Company's ability to serve its customers reliably, efficiently, and to a high standard requires an equally capable fleet. By methodically incorporating utilization processes that monitor fleet assets, the Company can maintain the fleet to manufacturers' specifications, as well as addressing the periodic wear and tear that comes with operating vehicles in often extreme conditions. Utilization data that monitors each type of vehicle can also assure that the Company is earning the best return on investment for the expected

environment said vehicle is designed to operate in. For example, the Company expects that investing in a sedan should provide a life expectancy of seven years and approximately 150,000 miles under normal service. Utilization for a vehicle of this type may differ as compared to a utility truck sent as needed to address concerns in the field or support customers as the need arises. However, for both types of vehicles, regular monitoring of utilization reports will help the Company plan for the replacement of each vehicle with regular use over time. Additionally, analysis of any under-utilized vehicles will inform decisions on how many future investments in that type of vehicle are made going forward. Customers benefit when the Company is making best use of its fleet to deliver service. Utilization data helps the Company right-size its fleet by identifying where additional units are needed to accommodate the Company's workforce, if there are any surplus units, and if existing units can be more effectively used by the Company, such as by moving units to a new location or new department.

**Q. Have there been right sizing efforts that benefit the customer?**

A. Yes. Since mid-2022, the Company has reduced its total number of units by approximately 450 units utilizing the tools described above. These right sizing efforts benefit the customer by reducing overall cost through reductions and/or allowing a particular unit to be effectively utilized in support of serving customers.

**Q. How does the Company's overall Fleet Vehicle Capital Replacement Plan benefit customers?**

A. Overall, the Fleet Vehicle Capital Replacement Plan allows the Company to retire and replace vehicles in a cost-effective way by using qualitative and quantitative inputs to identify units for replacement, particularly by identifying those units with high

maintenance costs and exhausted expected useful lifespans. Retiring and replacing those units in a systematic way is designed to keep maintenance costs down while ensuring that vehicles are available when needed to serve customers. The replacement planning process is a constantly self-evaluating cycle that relies on the data the fleet itself generates over time (mileage, age, and life cycle expectancy), inspections, maintenance and repair costs, and the local expertise to assist in prioritizing how the Company replaces units in the fleet. The customer benefits from this replacement planning process because the fleet is a crucial part of the overall service the Company provides. A replacement plan allows the Company to provide a safe, reliable, and cost-effective fleet to respond timely to utility outages, damaged utility service, utility service renewals, and new construction requests.

**Q. Are there further benefits related to safety, quality, and the planet when determining the Fleet Vehicle Capital Replacement Plan?**

A. Yes. By replacing vehicles in the fleet, newly introduced features from vehicle manufacturers are regularly incorporated into the Company's fleet, such as the following:

**Safety-**

- Backup sensors and rear-view cameras. This feature allows for safer backing, resulting in fewer rearward collisions, reducing vehicle and property damage, and increasing safety for the Company's customers and employees as well as collision avoidance and auto emergency braking, reducing collisions by advanced driver warning and applying brakes in advance of collision.

- Reduced stopping distance requirement from the Federal Motor Carrier vehicle safety standard for class 6-8 trucks. The standard distance required to stop a commercial vehicle was reduced, (National Highway Traffic Safety Administration 49 CFR Part 571, requiring a 30% reduction in stopping distance compared to currently required levels), which led to equipping trucks with larger braking systems to avoid collisions on buses and trucks manufactured on or after July 1, 2005.

- Light Emitting Diode ("LED") headlight technology. This allows a driver to see further down the road giving the driver more time to react to a situation.

LED headlights also save money due to less frequent bulb changes, thereby reducing time under repair.

**Quality-**

- Materials to manufacture vehicles are continuously advancing. For example, the Ford F-150 body is now stamped out of military grade aluminum, making the truck lighter, which increases fuel economy. Another added benefit of aluminum bodies is corrosion resistance, meaning less time and money spent repairing corrosion problems.

- Over the last 10 years, diesel engine exhaust gas recirculation coolers have improved, eliminating the need to replace them as frequently. This saves approximately $4,000 per replacement, where such replacements were occurring about every two years.

**Planet–**

- To align with National Highway Traffic Safety Administration's corporate average fuel economy standards, new vehicles are becoming more fuel efficient to align with their regulations. When replacing units within an appropriate lifecycle, the Company has an opportunity to purchase more fuel-efficient vehicles, including fully electric and plug-in hybrid vehicles where appropriate, ultimately reducing the Company's carbon footprint.

- Fossil fuel powered vehicles may be replaced with an EV if data supports electrification in that instance and could be a more fuel-efficient mode of transportation.

## III. FLEET ELECTRIFICATION STRATEGY

**Q. Does the Company plan to increase the number of EVs in its internal fleet?**

A. Yes, the Company is planning to increase the number of EVs in its fleet to reduce fleet fuel, maintenance, and operating costs, as well as lowering carbon dioxide tailpipe emissions to reduce greenhouse gases. For purposes of this testimony, the Edison Electric Institute's definition of an EV includes all vehicles with a plug, including Battery EV, Plug-in Hybrids, and anti-idle job site work systems such as electric Power Take Off systems ("ePTO") units.

**Q. How many EVs does the Company have in its internal fleet currently?**

A. The Company's fleet currently operates 284 EVs, representing approximately 5% of powered units in the overall fleet.

**Q. Does the Company have a target goal for electrification of its internal fleet?**

A. Yes, as noted by the Michigan Council for Future Mobility and Electrification in its 2021 report, the decade ending in 2030 will be notable in that the growth of EVs in the state will present new opportunities for the Company and its customers.[2] This is consistent with the testimony of Company witness Jeffrey A. Myrom in the Company's most recent electric rate case, Case No. U-21585. Leading by example, the Company has, therefore, set a goal of electrifying 30% of its internal fleet by the year 2030, including light, medium, and heavy-duty vehicles (class 1 through class 6 and higher), equipment and powered trailers, as well as electrifying all class 1 and 2 (light duty) vehicles after 2030.

**Q. How many vehicles does the Company plan to convert to electricity as a source of fuel by 2030?**

A. The internal fleet currently consists of approximately 5,700 powered vehicles eligible for replacement by potential EVs. This includes sedans, pickup trucks, bucket trucks, forklifts, and others. Electrifying 30% of these units would result in the replacement of approximately 1,700 internal combustion engine ("ICE") units with fully or partially EV powered units by 2030.

**Q. What types of vehicles does the Company expect to replace with EVs?**

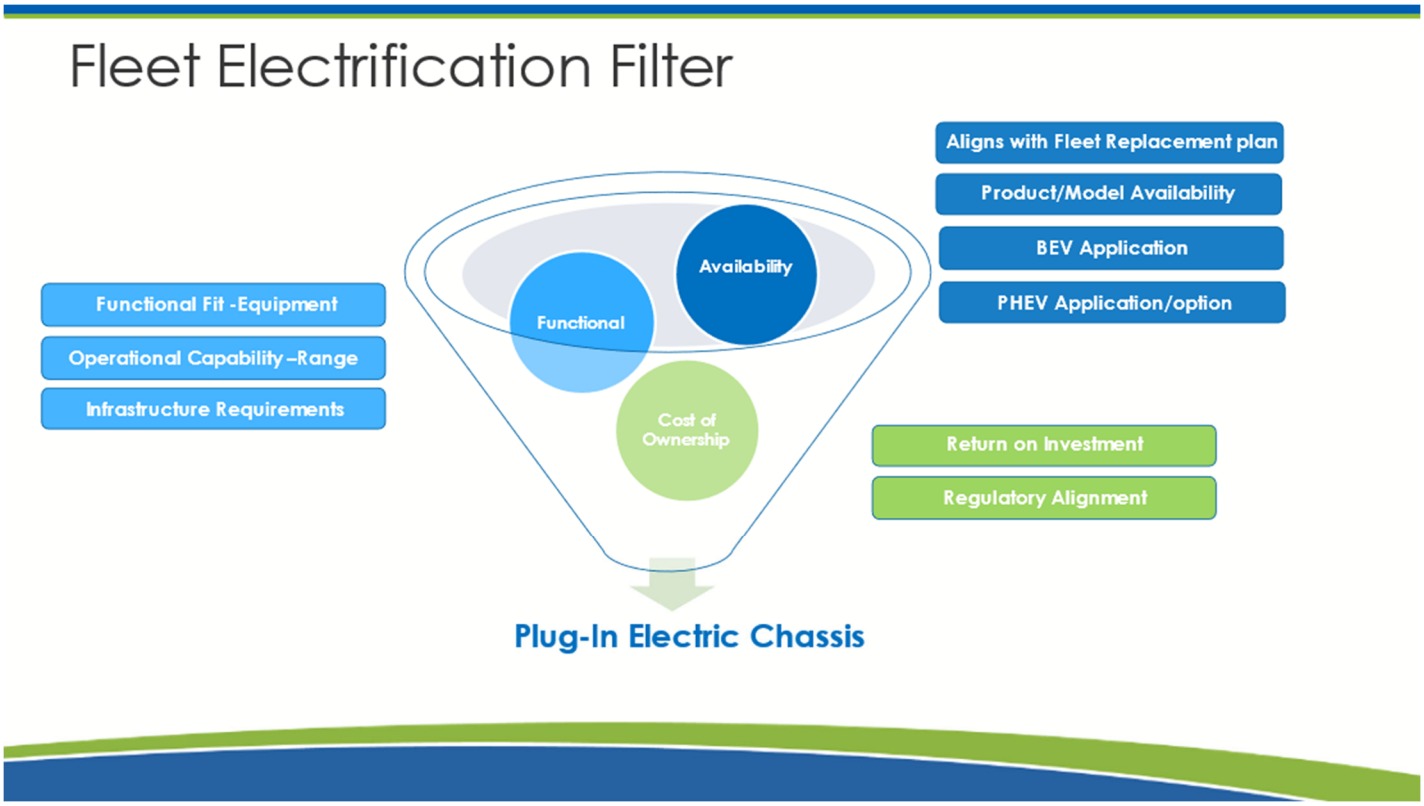
A. The Company expects that most of the initial ICE vehicles it will replace will be sedans and pickup trucks; however, as battery technology develops, there will be increasing

[2] cfme_report_2021_02.pdf (michigan.gov): https://www.michigan.gov/leo/-/media/Project/Websites/leo/Folder28/cfme_report_2021_02.pdf

availability for medium and heavy-duty vehicles to enter the market. For example, the Company has purchased one of the first available all electric bucket trucks in the world, which was delivered in the third quarter of 2024, as well as 20 all electric pickup trucks. The Company will deploy the electric bucket truck in its Grand Rapids location and has installed a DC Fast Charger there to support it.

**Q. How will the Company determine opportunities to replace ICE vehicles with EVs?**

A. The same replacement process, as discussed earlier in my testimony, will be used to determine opportunities to replace ICE vehicles with EVs, including the use of the Blended Factor, unit age, and overall condition analysis for each unit that has reached its end of life. Under this process, as a unit is targeted for replacement and reviewed according to the Replacement Plan, the unit is also considered for replacement with an EV. As the Electrification Filter shown below shows, consideration for electrification includes assessing a suitable replacement that is available in market, would have a functional role within the fleet, and lower cost of ownership. If the ICE under consideration for replacement meets the criteria required to pass through the filter, the unit is considered as an opportunity for replacement with an EV.




**Q. Why is the Company concerned by functional fit and equipment considerations?**

A. The Company partners with operational departments to understand how the potential replacement of an ICE vehicle with an EV will impact how teams complete their work. It is important to understand vehicle travel patterns, including mileage and driving duration, to assure that EVs are capable of supporting the work and have the travel range the Company needs to serve customers without compromise.

**Q. Why is the Company considering range concerns with EVs?**

A. As noted above, mileage range is a top consideration in determining how the Company integrates EVs into the fleet. It is critical to understand how current vehicles operate to determine potential EV replacement options, as well as infrastructure preparedness. The Company is utilizing its trip data, including mileage and location, to understand the best fit for each EV it is considering.

**Q. Why is functional fit a critical part of the EV decision making process?**

A. As with all other vehicles, the Company strives to ensure its Fleet aligns with industry best practices to serve the customer safely and efficiently. It will be important to consider, in addition to range, how an EV will support each department's ability to use it to its fullest capabilities, such as carrying tools and employees as required by the work.

**Q. How will the Company determine if EVs are performing as expected?**

A. The Company will be expanding its internal focus groups to provide real world feedback on barriers and opportunities to continuously improve how the Company adapts EVs in various operational environments. The Company will also study how EVs perform from a cost perspective, with lower maintenance and fuel costs expected.

**Q. In what ways are EVs more beneficial than ICE vehicles?**

A. Most of the benefits gained from utilizing EVs or battery-assisted systems arises from the changeover to electricity as the main source of energy, instead of gasoline or diesel fuels and petroleum-based maintenance materials. Electric motors require much less powertrain maintenance and repair, resulting in reduced maintenance costs, which is one of the key benefits of electrifying fleet units. A fully EV (battery) powered vehicle can also have up to 80% fewer parts than its ICE counterpart. With fewer internal parts, electric motors operate with less friction and more efficient use of energy. Many ICE vehicle parts require frequent and costly maintenance routines. Further, up to 65% of the heat energy produced by an ICE is wasted, requiring cooling systems which are prone to wear and eventual failure.

**Q. Can you please give examples of reductions in maintenance that will arise out of a transition from ICE vehicles to EVs?**

A. ICE vehicles contain hundreds of oil-lubricated parts that are required to convert the combustion of fossil fuels into the mechanical energy. Fluid changes extend to other components needed at various intervals in addition to engines and transmissions, including transfer cases and differentials throughout the life of all ICE vehicles. All these systems require regular maintenance and the associated costs in labor, parts, and materials to keep them at optimum performance and longevity. Over time, however, these components continue to wear even with diligent maintenance. This wear often leads to overheating issues, damaged or broken hoses, worn coolant pumps, or engine failure with the associated down time while undergoing repairs. EVs, on the other hand, do not require oil changes, spark plugs, fan belts, or tune ups. EVs also do not have transmission fluids that require periodic fluid changes, which makes them less prone to failure. Further, since an EV drive train requires less attention from a maintenance perspective, there is a reduced need for labor and/or material costs associated with this aspect of maintaining an EV. Plug-in EV hybrids often work with an ICE in conjunction with electric motors, reducing the fuel requirements for units equipped this way. Depending on the vehicle's configuration, a hybrid that features an ICE may need a maintenance schedule like a regular ICE vehicle; however, in most cases, plug-in hybrids help reduce overall fuel consumption with extended periodic maintenance requirements.

**Q. Are there other tools available to reduce fossil fuel consumption in ICE vehicles?**

A. Yes, there are idle-mitigation technologies, using plug-in battery systems, designed to reduce fuel consumption by reducing idle hours required to operate ancillary equipment

such as a boom on a bucket truck. By employing a plug-in battery and electric motor, for example, ePTO units can power hydraulic systems for short periods, reducing fuel consumption and engine wear. When engaged at a jobsite, an ePTO system can shut an idling engine off, and a battery-powered motor then powers the hydraulics needed to position the boom and bucket, as well as powering the climate control system in the cab. As a result, the bucket truck will operate quietly while the operator performs work near a customer's home because the sound of an idling diesel will not be present while the ePTO system is engaged. The Company already employs this technology to help reduce idling hours on several specs that operate booms on bucket trucks and cabin climate control. Additionally, ePTO systems can reduce fleet's overall carbon dioxide tailpipe emissions, as well as diesel particulates.

**Q. Has the Company undergone a concierge cost benefit analysis to help plan for internal EVs?**

A. Per Case No. U-20963, the Company has partnered with CALSTART, a national non-profit with over 30 years' experience in the private and public sectors with a proven track record working with over 280 member companies and agencies to build business cases for clean transportation technology adoption. CALSTART is a nationally respected team of fleet electrification experts who were selected by the Company via a competitive Request For Proposal. CALSTART has completed numerous fleet electrification assessments for external customers, in addition to the Company's. The assessments analyzed the Company's light duty fleet vehicles, by location, and daily miles driven to provide approximate load demand by location. EV location determination helps in understanding potential carbon emission avoidance and cost benefit analysis.

**Q. Does the Company solely rely on the CALSTART assessments for determining what EV to purchase?**

A. The Company does not rely solely on the assessment in its planning for EVs. CALSTART used the Company's own fleet-generated data to compile a list of recommendations for vehicle locations that are potentially suitable for electrification, the estimated load demand for those locations, and the associated charging information to support them. This information assists the Company during the decision-making process when considering EVs.

**Q. What quantifiable benefits of electrifying vehicles did CALSTART's assessment determine?**

A. CALSTART's assessment, noted above, concluded that the Company has the potential to lower fleet's overall fuel and maintenance costs by approximately 70%, excluding vehicle purchase price, combined over the lifetime of the vehicles that are electrified. The assessment also concluded that the Company could potentially reduce tailpipe emissions by approximately 90,000 metric tons.

**Q. Did the assessments provide suggestions for EV infrastructure support?**

A. The assessments provide specific location-based electric load demands estimates for the light duty EVs planned for replacement, as well as electricity as fuel cost estimates based on current mileage driven by ICE vehicles. For each service center/office location, the Company's ICE light-duty fleet data was analyzed for average daily miles driven and applied this information to determine the appropriate level of charger (Level 1 or Level 2) and the estimated corresponding energy demand for each vehicle. With this information, the Company can plan for the specific infrastructure electrical upgrades needed to support

the installation of Electric Vehicle Supply Equipment ("EVSE") at respective service centers with a measure of predictability based on the information the Company's ICE fleet has generated.

**Q. Is there a cost difference between EVs and conventional fossil fuel vehicles?**

A. Depending on make, model, and mileage range ratings, the purchase cost for an EV can vary as compared to an ICE vehicle. Currently, there are usually higher purchase costs associated with EVs that are comparable to ICE vehicles used by the Company to service its customers, such as all electric pick-up trucks.

**Q. Can you provide an example of a suitable EV for the Company?**

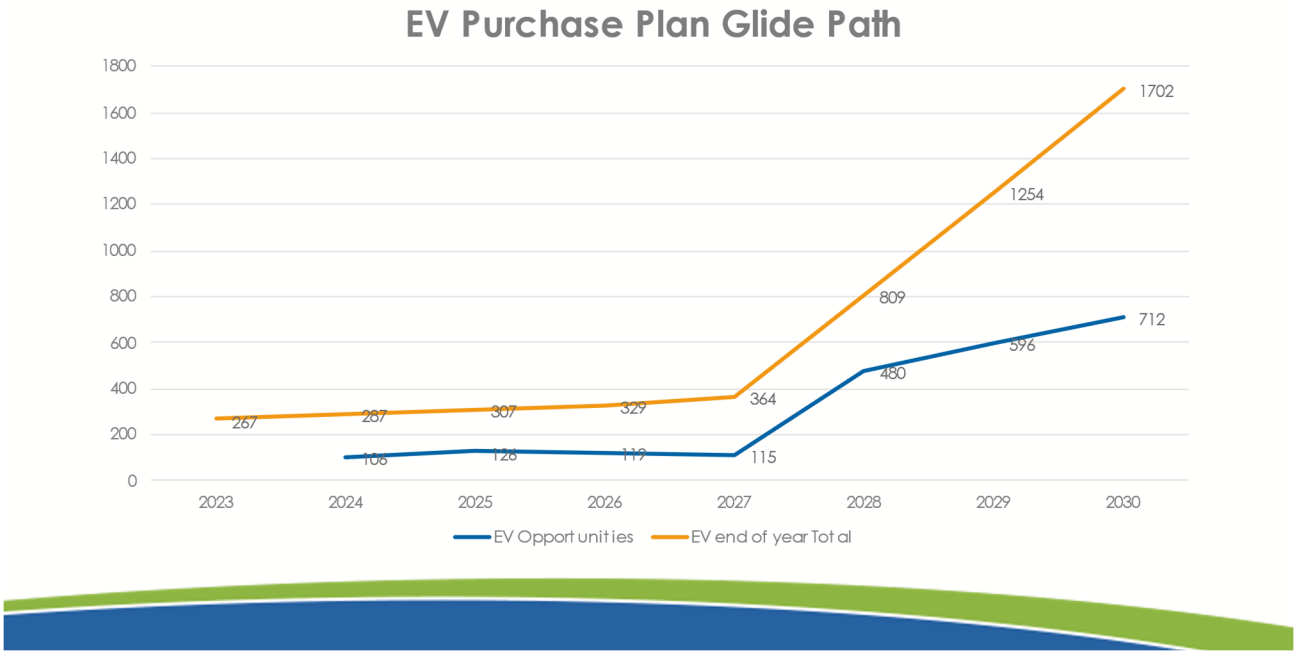
A. When considering an EV replacement, the Company seeks the closest EV equivalent to the out of lifecycle ICE under consideration for replacement. Currently, vehicles are more closely aligning with pickup trucks and economical sedans as most suitable for transportation and operational support.

**Q. Are there other associated projects being planned to support vehicle electrification efforts?**

A. Yes. To support the growth of EVs, the Company must plan for the increased electric load demands at most of its service centers to charge the EV units at those service centers. Since each center location will have a varying number of EVs and load demands, each location will require a specific power demand-based upgrade of its electric infrastructure for the installation of EVSE, also commonly known as "chargers." As noted earlier in my testimony, fleet has undergone a detailed data-based assessment to determine the load demands each facility will need to charge EVs daily.

**Q. How many EV opportunities are identified in the Five-Year Purchase Plan?**

A. The Five-Year Purchase Plan identifies approximately 450 potential opportunities to replace an ICE with an EV based on replacing units that have reached their end of life. As illustrated in the EV Purchase Plan Glide Path below, there are 106 light duty vehicles that could be replaced with an EV in 2024, and another 126 opportunities in 2025, 119 in 2026, and 115 in 2027. With limited opportunities to make ICE to EV replacements through 2027, the Company would need to invest additional funding above the currently approved capital replacement funding for the purchase of approximately 450 EVs over and above what the Purchase Plan identifies as a replaceable unit each year in 2028, 2029, and 2030 to reach the Company's goal of approximately 1,700 EVs.



**Q. Is the market for vehicle electrification currently able to supply the vehicles needed to support the Company's goal?**

A. Lead times for some EVs and vehicles equipped with idle mitigation systems are often two or more years out. The resources required by manufacturers to build enough units to meet high demand are not in alignment, which has often led to short supplies for both commercial and private customers; however, the market's availability of EVs suitable as fleet vehicles is still a relatively small part of the EV market. Currently, a substantial portion of the fleet EV market consists of vehicles that do not meet the criteria for cost and features best suited for use by the Company. For example, the Company prefers Original Equipment Manufacturer ("OEM") vehicles from Michigan-based companies, such as GM and Ford, as well as meeting all the requirements noted as part of the Fleet Electrification Filter. The recent fall in EV demand for EV pick-up trucks has shifted manufacturer focus to other models or delayed the development of new EVs. There are many startup companies with potentially viable EV units; however, the Company prefers to limit the potential exposure to the risks associated with startup company products.

**Q. How does limited availability of EVs effect the Company's glidepath to its goal?**

A. The Company's ability to increase the number of EV units in the fleet remains flat through 2027. At this time, limited market EV availability may prevent the Company from ordering the suitable number of EV units needed to affect a more linear glidepath toward the 2030 goal. Also, the EV opportunities identified in the Purchase Plan averages about 117 units per year. If the Company continues to purchase EV units at an average of 117 units per year, the goal to electrify 30% of the fleet will not be met by 2030.

**Q. What EV units does the Company plan to purchase for the Test Year?**

A. The Company is planning to replace nine ICE pick-up trucks with nine all electric Chevrolet Silverado EV pick-up trucks.

**Q. How will the Company determine the locations to assign EV vehicles?**

A. All EVs will be assigned to departments and teams that are best able to utilize the benefits of an EV during their daily job functions. As discussed earlier in my testimony, the assessment from CALSTART provides a summary of miles driven by location, allowing the Company to understand where an EV can be best utilized. For example, where the data shows an ICE pickup truck is typically driven 75 to 150 miles per day and returns to its respective service center, that vehicle could be eligible to be replaced with an EV of similar capability and range because the data suggests a good fit for an EV. The Company can reference the assessment data to help make the most informed decisions on their deployment. The Company also partners with operations to determine if an EV will meet the requirements of their work processes at a particular location.

**Q. What associated infrastructure support will the EVs planned for the Test Year require?**

A. The EV units will require chargers installed at their planned respective headquarters to support their charging requirements. The planned headquarter locations that will need EV chargers installed are as follows: Flint, Hamilton, Saginaw, Big Rapids, Norton Shores, Greenville, and Fremont.

**Q. How does electrifying 30% of the Company's fleet by 2030 benefit the customer?**

A. The Company's efforts to electrify a portion of the internal fleet will benefit the customer in several ways. The Company seeks to lower Fleet's overall operating costs by reducing

its reliance on fossil fuels, which will bring lowered maintenance costs for reasons mentioned earlier in this testimony. By shifting the cost of refueling an ICE unit from gasoline or diesel to overnight charging, the Company can save money on fuel wherever mileage powered by fossil fuels can be shifted to lower cost charging overnight rates. Over the lifetime of these vehicles, by utilizing electricity to power 30% of the fleet, the Company seeks to leverage the relative stability and lower cost electricity offers over the more volatile cost of petroleum-based fuels and lubricants. Reducing the Company's reliance on ICE vehicles brings significant reductions in the maintenance costs associated with the upkeep of fossil fuel-based drivetrains. With fewer mechanical parts to maintain, EVs require lower maintenance budgets and fewer parts that can potentially fail over the lifetime of the vehicle.

Lastly, by lowering its reliance on fossil fuels, the Company seeks to lower its overall carbon dioxide emissions from Fleet's operations. Fully electrified vehicles have zero tailpipe emissions and, where applicable, hybrid vehicles and other technologies (like idle mitigating ePTO systems) also offer carbon reductions as well. Where idle mitigation systems are employed with diesel engines, reduced idling lowers particulates, or soot, generated with the combustion of diesel fuel. The Company's customers will benefit from the efforts to mitigate pollution, reduce greenhouse gas emissions, and lower its overall operating costs related to operating its internal fleet.

## IV. FLEET SERVICES CAPITAL SPENDING PROJECTIONS

**Q. Please describe the capital expenditures related to Fleet Services as shown on Exhibit A-12 (CEB-1), Schedule B-5.2.**

A. Exhibit A-12 (CEB-1), Schedule B-5.2, provides gas Fleet Services capital spending, broken down into four capital spending categories: (i) Fleet Vehicle Capital Replacement, (ii) Fleet Vehicle Electrification, (iii) Fleet Business Partner Funded, and (iv) Fleet Tools - Garage. Exhibit A-12 (CEB-1), Schedule B-5.2, provides these capital expenditures with actuals for the 12 months ended December 31, 2023; projections for the 12 months ending December 31, 2024; 10 months ending October 31, 2025; 22 months ending October 31, 2025; and projections for the 12 months ending October 31, 2026, which is the test year in this case. For the historical year, 12 months ended December 31, 2023, the Company incurred Fleet Services capital expenditures in the amount of $9.405 million. The Company is projecting gas Fleet Services capital expenditures to be $9.925 million for the 12 months ending December 31, 2024; $7.048 million for the 10 months ending October 31, 2025; $16.973 million for the 22 months ending October 31, 2025; and $13.532 million in the projected test year ending October 31, 2026, as set forth in Exhibit A-12 (CEB-1), Schedule B-5.2, line 5, columns (b) through (f), respectively.

**Q. Are there any contingency costs included in the Company's projected Gas Fleet Services capital expenditures?**

A. No.

**Q. What types of expenditures are included in Fleet Vehicle Capital Replacement Plan and Fleet Vehicle Electrification capital spending?**

A. Details of the Fleet Vehicle Capital Replacement Plan are included in Exhibit A-28 (CEB-3). Fleet Vehicle Electrification expenditures include the additional cost of nine Chevrolet Silverado EV pickup trucks.

**Q. What types of expenditures are included in Fleet Business Partner Funded?**

A. Fleet Business Partner Funded expenditures include additional units purchased to support the Company's Advanced Methane Detection ("AMD") Systems, and one fully electric pick-up truck supporting PowerMIFleet education and outreach initiatives, both are described in detail later in my direct testimony.

**Q. What types of expenditures are included in Fleet Tools?**

A. Fleet tool purchases include the following: diagnostic equipment, tool sets, ergonomic tooling, and specialty equipment to properly and safely service and repair fleet vehicles, equipment, and trailers. This is described in detail later in my direct testimony.

**Q. How did you determine the appropriate distribution of capital costs among the cost categories shown on Exhibit A-12 (CEB-1), Schedule B-5.2?**

A. As required by the Commission's filing requirements, the Company itemized the capital investments for Transportation Equipment by using the following cost categories: contractor, labor, materials, business expenses, and other. The Company breaks out these cost categories by calculating a five-year historical average of each of the Commission's prescribed cost categories from years 2019 and 2023 as a percentage of total Transportation Equipment investment over that same period. The five-year historical average for each cost category was then applied to the Transportation Equipment Program's projected

capital spending for the bridge year and the test year to arrive at estimates for each cost category (i.e. contractor, labor, materials, business expenses, and other). This method is consistent for the projected test year presented in Exhibit A-12 (CEB-1), Schedule B-5.2.

**A. Fleet Vehicle Capital Replacement Plan**

**Q. What level of Fleet Vehicle Capital Replacement Plan spending is proposed in this case?**

A. As shown in Exhibit A-12 (CEB-1), Schedule B-5.2, the Company is proposing to spend $9.664 million in the 2024 bridge year; $6.605 million for the 10 months ending October 31, 2025; $16.269 million for the 22 months ending October 31, 2025; and $12.923 million in the 12 months ending October 31, 2026 test year on Fleet Vehicle Capital Replacement Plan spending.

**Q. How did the Company determine its 2023 through 2026 Fleet Vehicle Capital Replacement Plan for the instant case, including the appropriate level of investment?**

A. The Company is keeping Fleet Vehicle Capital Replacement Plan spending in 2023 through 2026 at historical spending levels, adjusted for inflation, based on what the Commission has previously approved for "lifecycle replacement spending." By remaining at this level for 2023 through 2026, the Company is demonstrating its commitment to keeping costs affordable for customers. This set of vehicles was described earlier in my testimony, as shown in Exhibit A-28 (CEB-3).

**Q How did the Company develop the list of vehicles that is projected to be purchased in years 2023 through 2026 of this case?**

A. The specific units that the Company plans to purchase 2023 through 2026 are also shown in Exhibit A-28 (CEB-3). The Company produced an initial list of vehicles for replacement

using the Blended Factor algorithm described earlier in my testimony, with a spreadsheet showing a Blended Factor percentage for each vehicle in the Company's fleet. This list was prioritized by the Blended Factor percentage to highlight vehicles that generate a positive (above 0.0%) percentage (the mathematical result of the Blended Factor calculation), which indicates that a vehicle has reached its expected life. Following the Blended Factor Analysis, as described previously in this testimony, the Replacement Plan filter included a review of market availability. By reviewing market availability, the Company can determine which replacement specifications can be expected for delivery through 2026. Vehicles that are likely not available for delivery in 2024 were not considered for replacement. To further refine the list of vehicles, standard crewing models were assessed. Though the Company will be continuing an analysis on right sizing, standard modeling helped guide the decision-making process.

**Q. Was there additional analysis in determining the Fleet Vehicle Capital Replacement Plan for 2025 and 2026?**

A. Yes. The list was further reviewed from a cost and utilization perspective. By assessing how often vehicles are used, the Company selected vehicles with a higher utilization rate when compared to similar specifications. The Company further narrowed the initial Blended Factor-based list based on fleet stakeholders' input on condition. In this step, vehicles were assessed by age, mileage, and overall condition, and associated operating costs and mechanical improvements, such as a newly installed engine. Vehicles that received recent substantial investments (new engines, for example) are removed from the potential replacement list because their expected life is generally extended following such investments.

**Q. Does the Company anticipate variances in future fleet spending?**

A. While the Company attempts to be as precise as possible in the Fleet Replacement Plan, there is the potential for variances slightly above or below projected budget due to the nature of the fleet business that includes supply chain challenges. However, the Company continues to be good stewards of the fleet by working to meet all projected expenditures as close to targeted goals as possible.

**B. Fleet Vehicle Electrification**

**Q. In the projected test year, 12 months ending October 31, 2026, the Company is projecting an investment of $360,000 for EVs. What is included in this amount?**

A. As shown in Exhibit A-12 (CEB-1), Schedule B-5.1, the Company is proposing to spend $360,000 in the 12 months ending October 31, 2026 test year on Fleet Vehicle Electrification.

**Q. What kind of purchases are included in Fleet Vehicle Electrification?**

A. As shown in Exhibit A-28 (CEB-3), line 3, column (b), Fleet Vehicle Electrification purchases include nine Chevrolet Silverado EV pickup trucks.

**Q. Why are the expenditures presented for Fleet electrification appropriate?**

A. Fleet expenditures requested will be used to bridge the price gap difference between a standard ICE pickup truck and a plug-in EV pickup truck of similar function. The proposed spending would fund the purchase price difference between a standard ICE pickup truck and its EV equivalent, which in this case is a Chevrolet Silverado EV. The purchase price difference between an ICE pickup truck chassis and an EV pickup truck chassis is approximately $40,000, totaling approximately $360,000 for nine Chevrolet Silverado

EVs. The addition of these EVs will further the Company's efforts to reduce fuel and maintenance costs, as well as its overall carbon footprint.

**Q. Why is the Company requesting only the purchase price difference between an ICE vehicle and an EV in this case?**

A. Due to these vehicles being part of the replacement plan process, the funding to replace an ICE chassis is already being requested as part of the capital replacement plan. Therefore, the Company is only requesting to add the purchase price difference between a standard ICE chassis and the electrification cost of its replacement unit.

**Q. How do these capital expenditures benefit customers?**

A. The expenditures in vehicle electrification will benefit the customer in several ways. EVs and plug-in hybrids are expected to lower the Company's overall fuel and maintenance costs as compared to ICE powered vehicles. The EVs proposed also offer significant potential reductions in greenhouse gas emissions, increasing the Company's carbon avoidance efforts, while providing service to customers with less pollution at lower cost. Lastly, the units proposed for the Test Year will further the Company's learnings on EV best practices, planning, and deployment as it increases fleet electrification.

### C. Fleet Business Partner Funded

**Q. In the 12 months ending December 31, 2023, the Company funded a partner -funded investment of $160,000. What is included in this amount?**

A. As shown in Exhibit A-12 (CEB-1), Schedule B-5.2, line 3, column (b), the Company invested approximately $160,000 to fund one fully electric pick-up truck supporting PoweMIFleet education and outreach initiatives funded by that pilot, as well as three SUVs with AMD Systems for the Gas Strategy department within Gas Engineering and Supply.

**Q. How did you determine the needed level of spending for the partner funded equipment?**

A. A low-cost electric truck configuration from a Michigan-based manufacturer was selected that would have sufficient range for engaging at customer outreach events and discussions on electrification with fleets considering electrification. The vehicles purchased for AMD are suitable for advanced leak surveying requirements to provide vehicles that are capable of safely and efficiently transporting the driver and sensitive methane diagnostic and detection measuring equipment.

**Q. How do these capital expenditures benefit the customers?**

A. EVs are a technology change for almost all fleet customers. Given this, being able to see and experience an EV is important for customer education regarding infrastructure and charging requirements. Furthermore, by Consumers Energy modeling electric fleet adoption, customers have more confidence in the information being received from PowerMIFleet.

**Q. Has the Commission previously approved spending for this partner-funded equipment?**

A. Yes. The Commission approved spending for PowerMIFleet administration and customer outreach in its Order in Case No. U-20697.

**Q. What concerns does Fleet Services have if the proposed capital expenditure amounts for expansion are not approved?**

A. Presently, Consumers Energy has two smaller sedan EVs (i.e. Chevy Bolts) that are utilized for customer events and educational outreach. With a limited light duty fleet, the Company loses the ability to expand its education internally as well as externally. Data points from

expanding into a larger class vehicle can educate the Company about return-on-investment potential and the ability to serve during normal and critical operations.

In addition, the state-of-the-art methane detection equipment used for AMD requires a reliable, robust platform to function optimally. The vehicles selected to be used in conjunction with this equipment provide the appropriate space to operate the equipment but also allows for the room required to service and repair the mobile lab the units must carry to perform the task. If investments are not made to purchase the units supporting the AMD Systems, the Company will not be able to implement and take advantage of the AMD's benefits.

**D. Fleet Tools**

**Q. What kind of purchases are included in Fleet Tools?**

A. Fleet tool purchases include the following: diagnostic equipment, tool sets, ergonomic tooling, and specialty equipment required to properly service and repair fleet vehicles, equipment, and trailers.

**Q. What level of expenditures is included in this rate case for Fleet Tools?**

A As shown in Exhibit A-12 (CEB-1), Schedule B-5.2, the Company is proposing to spend $238,000 in the 2024 bridge year; $203,000 for the 10 months ending October 31, 2025; $441,000 for the 22 months ending October 31, 2025; and $249,000 in the 12 months ending October 31, 2026 test year on Fleet Garage Tools. A further breakdown of this tooling type per year can found on Exhibit A-29 (CEB-4).

**Q. Why are the expenditures presented for Fleet Tools appropriate?**

A. To properly repair vehicles in a compliant, safe, and efficient manner, it is necessary to have the right tool for the task at hand. The tooling can be anything from diagnostic

tooling, electronic service information, tool sets, or a new air conditioning recovery/recycle/recharge machine required to properly service R1234yf refrigerant. Diagnostic tooling is necessary for the repair of most vehicle systems such as the engine, transmission, air bag, lighting, and anti-lock brakes. This tooling requires updates to maintain access to new vehicle models. Electronic service information is required to diagnose vehicle concerns and to follow the manufacturer's recommended repair procedures. Additional tooling such as hydraulic torque wrenches are critical in ensuring that high torque fasteners requiring very high torque applications are properly set and adjusted to manufacturer torque specifications to ensure safe repairs and inspections. Maintenance equipment, such as an R1234yf air conditioning machine, are required to meet Environmental Protection Agency standards for safely recovering and recharging air conditioning systems on newer model year vehicles.

**Q. What benefits does this level of Fleet Tools spending provide to customers?**

A. Across the state, the Company has 36 locations where Fleet mechanics are permanently stationed to perform their daily work. The Company also has remote sites, training facilities, and jobsite reporting locations where repairs to vehicles and equipment are also performed. The projected Fleet Tools for 2025 spending is approximately $494,000 for the entire Company, or approximately $13,700 for each of the 36 locations where mechanics are stationed. The gas allocation of this total is approximately $244,000. Each year, the Company replaces, and updates outdated or unrepairable shop equipment such as floor jacks, diagnostic equipment, tire machines, and welders. The benefit to customers of having tools in good order is less downtime for vehicles and reduced maintenance expenses because the Company is not solely reliant on outside repair shops to complete work needed

to keep vehicles active. Most repair and maintenance items are performed by the Company's in-house mechanics; therefore, it is imperative that the Company maintain a complete and updated inventory of tools to complete the work required.

**Q. Does this conclude your direct testimony in this proceeding?**

A. Yes.

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

| | | |
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| In the matter of the application of **CONSUMERS ENERGY COMPANY** for authority to increase its rates for the distribution of natural gas and for other relief. | ) ) ) ) ) ) | Case No. U-21806 |

**REDACTED**

# REBUTTAL TESTIMONY

# OF

# QUENTIN A. GUINN

# ON BEHALF OF

# CONSUMERS ENERGY COMPANY

May 2025

**Q. Please state your name and business address.**

A. My name is Quentin A. Guinn, and my business address is One Energy Plaza, Jackson, Michigan 49201.

**Q. Are you the same Quentin A. Guinn who previously filed direct testimony in this proceeding?**

A. Yes. I am also adopting the direct testimony and exhibits of Consumers Energy Company ("Consumers Energy" or the "Company") Company witness Corey E. Ballinger.

**Q. What is the purpose of your rebuttal testimony?**

A. The purpose of my rebuttal testimony is to address Attorney General Dana Nessel ("Attorney General") witness Sebastian Coppola's recommendation that the Michigan Public Service Commission ("MPSC" or the "Commission") remove Fleet Services forecasted capital expenditures of $1,202,000 for the 10 months ending October 2025 and $4,809,000 for the 12 months ending October 2026 for Fleet Vehicle Capital Replacement and Fleet Vehicle Electrification. I will also address Citizens Utility Board of Michigan's ("CUB") witness Joshua W. Denzler's recommendations that: (i) the Commission remove Fleet Services forecasted capital expenditures of $3,390,000 for the 22 months ending October 31, 2025 and $2,580,000 for the 12 months ending October 31, 2026 for Fleet Vehicle Capital Replacement Spend; (ii) the Commission reduce Fleet Services forecasted Operating and Maintenance ("O&M") expenses by [redacted] for the 12 months ending October 31, 2026 for Fleet Responsibility costs; (iii) the Commission order the Company to conduct a more specific study as to the expected savings of electrifying its fleet assets, by asset type (e.g., light duty car, pickup, van, heavy-duty, etc.) and provide the study in its next gas rate case with results incorporated into future requested cost recovery; (iv) the

Commission reduce Fleet Responsibility costs by $15,008,000 in 2025 and $15,008,000 in 2026; (v) the Commission order the Company to provide historical and projected fleet responsibility costs by capital and O&M, with more detailed information on the types of work these dollars support and the value received for these expenditures, by cost category and business unit for future rate cases; (vi) the Commission order the Company to prepare a more detailed analysis of its vehicle idling; (vii) the Commission remove Facility Operations forecasted capital expenditures of $14,937,000 for the 22 months ending October 31, 2025 for the Lansing Service Center Project; (viii) the Commission remove Facility Operations forecasted capital expenditures of $7,199,000 for the 12 months ending October 31, 2026 for the Lansing Service Center Project; (ix) the Commission remove Facility Operations forecasted capital expenditures of $114,000 for the 22 months ending October 31, 2025 for the Hastings Service Center Project; (x) the Commission remove Facility Operations forecasted capital expenditures of $4,380,000 for the 22 months ending October 31, 2025 for the Kalamazoo Service Center Project; and (xi) the Commission remove Facility Operations forecasted capital expenditures of $616,000 for the 12 months ending October 31, 2026 for the Kalamazoo Service Center Project.

**Q. Are you sponsoring any exhibits in connection with your rebuttal testimony?**

A. No.

**Q. Does the Company agree with Attorney General witness Coppola's recommendation on page 99 of his direct testimony that the Commission remove Fleet Services forecasted capital expenditures of $1,202,000 for the 10 months ending October 2025 and $4,809,000 for the 12 months ending October 2026 for Fleet Vehicle Capital Replacement and Fleet Vehicle Electrification?**

A. No. Mr. Coppola's proposed reduction is based on an average cost per vehicle in 2024, inflating that cost by inflation factors for 2025 and 2026, and multiplying the resulting average cost by the number of vehicles planned to be purchased in those years. The Company does not purchase the same combination of vehicles each year. Therefore, the average cost per vehicle in the Company's Vehicle Replacement Plan may vary considerably from year to year, and the Company's projected unit costs are based on current manufacturer pricing. The Company's total Fleet Vehicle Capital Replacement Cost is the relevant metric for gauging year-over-year growth in capital spend. For the gas Fleet Vehicle Capital Replacement expenditures, the 2024 projected spend is $9.687 million and the 2025 projected spend is $9.919 million, a 2.4% increase.

**Q. Does the Company agree with CUB witness Denzler's recommendation on page 19 of his direct testimony that the Commission remove Fleet Services forecasted capital expenditures of $3,390,000 for the 22 months ending October 31, 2025 and $2,580,000 for the 12 months ending October 31, 2026 for Fleet Vehicle Capital Replacement Spend?**

A. No. Mr. Denzler recommended a 20% reduction in these expenditures based on his argument that the Company did not demonstrate the reliability of the Blended Factor model in making vehicle replacement decisions. First, as outlined on pages 8 through 12 of

Company witness Ballinger's direct testimony, the Blended Factor is only one of multiple quantitative and qualitative factors used to make vehicle replacement plan decisions. The efficacy of the Company's replacement plan decision making does not rest solely on the Blended Factor. Second, on page 18 of his direct testimony, Mr. Denzler cites a few instances in which the Company's Blended Factor model failed to accurately predict vehicle failure. As noted on page 12 of Company witness Ballinger's direct testimony, there are over 7,200 units in the Company's vehicle fleet. Therefore, the failure of the Blended Factor to accurately predict a few vehicle failures in this portfolio of over 7,200 assets during the course of several years does not statistically disprove the reliability of the Blended Factor model. Third, Mr. Denzler does not provide any calculation or explanation as to why a 20% disallowance is appropriate for projecting vehicle replacement costs as a result of Mr. Denzler's concerns with the use of the Blended Factor. Finally, the Company has included express reference to the Blended Factor in electric and gas rate case testimony for Fleet Services since the Commission's order issued in Case No. U-20963 in December 2021. During this nearly four-year period, the Commission's orders have not questioned the reliability of the Company's Blended Factor model.

**Q. Does the Company agree with CUB witness Denzler's recommendation on page 21 of his direct testimony that the Commission reduce for Fleet Services forecasted O&M expenses of [redacted] for the 12 months ending October 31, 2026 for Fleet Responsibility expense because this total estimated fuel and maintenance savings from electric vehicles ("EVs") in the Company's fleet?**

A. No. First, Mr. Denzler derived the O&M estimate from an analysis outlined on pages 20 and 21 of his direct testimony. Mr. Denzler's figure, however, is still an estimate based on

estimated savings across the major categories of passenger EVs owned by the Company. In response to discovery request U21806-AG-CE-0229, the Company indicated that it "has not yet incorporated specific fuel, maintenance and other savings assumptions into its budget projections for the replacement of an ICE [internal combustion engine] vehicle with an EV. Deployment of the Test Year units proposed in this case will provide empirical data needed to establish accurate assumptions about fuel, maintenance and other savings to be realized upon replacing ICE vehicles with EVs." Thus, it is premature to include these estimated savings in the projections in this case. Finally, it would be incorrect to assume that these types of savings would be entirely O&M. Fleet Responsibility costs include both an O&M and capital component, estimated in total at approximately ~~75~~67% capital and ~~25~~33% O&M based on historical actuals.

**Q. How do you respond to CUB witness Denzler's recommendation on page 21 of his direct testimony that the Company conduct a more specific study as to the expected savings of electrifying its fleet assets?**

A. The Company agrees to provide more specific information regarding expected savings from electrifying its fleet assets in future cases.

**Q. Does the Company agree with CUB witness Denzler's recommendation on page 23 of his direct testimony that the Commission remove forecasted Fleet Responsibility costs of $15,008,000 in 2025 and $15,008,000 in 2026?**

A. No. First, as noted on pages 6 and 7 of Company witness Ballinger's direct testimony, Fleet Responsibility costs are incurred to maintain the Company's vehicle fleet. Exhibit A-27 (CEB-2) includes annual historical Fleet Responsibility costs from 2016 through 2023. The amounts in Exhibit A-27 (CEB-2) represent actual Fleet Responsibility costs

and during this eight-year period the Commission never determined that these expenses are not reasonable or prudent. Second, Mr. Denzler notes that the Company is estimating approximately $75 million in Fleet Responsibility costs in 2025 and 2026. Given that actual Fleet Responsibility costs were $86.7 million in 2022 and $80 million in 2023 as shown in Exhibit A-27 (CEB-2), it would not be reasonable to reduce these expected costs by 20% of $75 million in 2025 and 2026. In addition, as discussed above, Fleet Responsibility costs include both an O&M and capital component, estimated in total at approximately ~~75~~67% capital and ~~25~~33% O&M. If the Commission adopted a disallowance of Fleet Responsibility costs, which it should not, the disallowance should be ~~75~~67% capital and ~~25~~33% O&M.

**Q. Does the Company agree with CUB witness Denzler's recommendation on page 23 of his direct testimony that the Company provide historical and projected fleet responsibility costs by capital and O&M, with more detailed information on the types of work these dollars support and the value received for these expenditures, by cost category and business unit in future rate cases?**

A. The Company agrees to provide the additional requested detail regarding Fleet Responsibility costs in future cases.

**Q. Does the Company agree with CUB witness Denzler's recommendation on pages 26 and 27 of his direct testimony that the Company prepare a more detailed analysis of its vehicle idling?**

A. The Company agrees to work on performing such an analysis.

**Q. Does the Company agree with CUB witness Denzler's recommendation on pages 29 and 30 of his direct testimony that the Commission remove Facility Operations forecasted capital expenditures of $14,937,000 for the 22 months ending October 31, 2025 for the Lansing Service Center Project?**

A. The Company disagrees with a portion of Mr. Denzler's recommendation. As outlined in response to discovery request U21806-AG-CE-0652, the Company's capital expenditures for the Lansing Service Center Project totaled $1,817,000 for the 12 months ended December 31, 2024. The Company's actual capital expenditures totaling $1,817,000 for the Lansing Service Center for the 12 months ended December 31, 2024 should be approved because they have actually been spent on the project. Based on the Commission's determination in Case No. U-21585, the Company will not oppose removal of the remaining forecasted capital expenditures of $13,120,000 ($1,817,000 less than Mr. Denzler's recommended $14,937,000) for the 22 months ending October 31, 2025 for the Lansing Service Center Project. The Company will present post-2024 expenditures for approval in a future rate case.

**Q. Does the Company agree with CUB witness Denzler's recommendation on pages 29 and 30 of his direct testimony that the Commission remove Facility Operations forecasted capital expenditures of $7,199,000 for the 12 months ending October 31, 2026 for the Lansing Service Center Project?**

A. Based on the Commission's Order in Case No. U-21585, the Company will not oppose this recommendation. The Company will present these expenditures for approval in a future rate case.

**Q. Does the Company agree with CUB witness Denzler's recommendation on page 31 of his direct testimony that the Commission remove Facility Operations forecasted capital expenditures of $114,000 for the 22 months ending October 31, 2025 for the Hastings Service Center Project?**

A. No. The Company disagrees with a portion of this recommendation. As outlined in my response to discovery request U21806-AG-CE-0652, the Company's capital expenditures for the Hastings Service Center Project totaled $95,000 for the 12 months ended December 31, 2024. The Company's capital expenditures totaling $95,000 for the Hastings Service Center Project for the 12 months ended December 31, 2024 should be approved because they have actually been spent on the project. Based on the Commission's determination in Case No. U-21585, the Company will not oppose removal of the remaining forecasted capital expenditures of $19,000 ($95,000 less than Mr. Denzler's recommended $114,000) for the 22 months ending October 31, 2025 for the Hastings Service Center Project. The Company will present post-2024 expenditures for approval in a future rate case.

**Q. Does the Company agree with CUB witness Denzler's recommendation on page 32 of his direct testimony that the Commission remove Facility Operations forecasted capital expenditures of $4,380,000 for the 22 months ending October 31, 2025 and $616,000 in the test year for the Kalamazoo Service Center Project?**

A. No. Mr. Denzler's argument that the project is being overbuilt by 40% is incorrect. At page 31 of his direct testimony, Mr. Denzler points to the Company's statement that the renovation will "incorporate and allow for up to 40% future growth opportunities" for his contention that the facility is being overbuilt by 40%. The Company is renovating its

existing Kalamazoo Service Center. As outlined on pages 29 and 30 of my direct testimony in this case, the Company did not construct or add space to the existing facility as part of this renovation. Rather, the footprint of the existing Kalamazoo Service Center is unchanged with renovations being done to the facility as is. While the Company could reduce the size of the facility as part of this renovation by demolishing a portion of the building, demolition of part of the building would add considerably to the cost of this project. It is far more cost effective to simply utilize existing space as is.

**Q. Does this conclude your rebuttal testimony?**

A. Yes.

(Revised Rebuttal Testimony bound in in Confidential Record)

MR. RUSZKIEWICZ: The Company's next witness is Kirkland D. Harrington. And based on the stipulation of the parties, the Company moves to bind in the testimony of Mr. Harrington, which consists of a cover page and four pages of direct prefiled testimony. The Company also moves to admit the exhibits of Mr. Harrington, which are A-71, and A-16 Schedule F-5.

JUDGE VARCHETTI: Are there any objections to the admission of Mr. Harrington's testimony or any of the associated exhibits?

Hearing none, the testimony is bound into the record and the exhibits are admitted.

MR. RUSZKIEWICZ: Thank you.

(Direct Testimony bound in)

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

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| In the matter of the application of<br>**CONSUMERS ENERGY COMPANY**<br>for authority to increase its rates for the<br>distribution of natural gas and for other relief. | )<br>)<br>)<br>)<br>) | Case No. U-21806 |

**DIRECT TESTIMONY**

**OF**

**KIRKLAND D. HARRINGTON**

**ON BEHALF OF**

**CONSUMERS ENERGY COMPANY**

December 2024

**Q. Please state your name and business address.**

A. My name is Kirkland D. Harrington, and my business address is One Energy Plaza, Jackson, Michigan 49201.

**Q. By whom are you employed and in what capacity?**

A. I am employed by Consumers Energy Company ("Consumers Energy" or the "Company") as a Tariff Analyst in the Rates and Regulation Department.

**Q. Please describe your educational background.**

A. I received a Dual BBA in Marketing and Management in June 2010 from Northwood University.

**Q. Please describe your work experience at Consumers Energy.**

A. In March 2013, I was hired by Consumers Energy as a Customer Service Representative within the Company's call center. In May 2017, I accepted a role as a Customer Service Revenue Recovery Assistant within the Energy Assistance department. In November 2018, I accepted a role as a Technical Assistant within Gas Distribution Scheduling where my duties included ensuring proper permitting and safe access to work sites by facilitating coordination between local municipalities and governmental departments. In December 2022, I joined the Rates and Regulation department as a General Rate Analyst in the Rate Administration section. In June 2023 my position title was updated to Tariff Analyst.

**Q. Please describe your responsibilities as a Tariff Analyst.**

A. My responsibilities include development and implementation of the Company's tariffs. I also perform regulatory research, prepare rate comparisons, review Commission orders, and legislation.

**Q. Have you previously provided testimony before the Commission?**

A. Yes. I have sponsored the Company's proposed tariff changes and rate schedules in general gas rate Case No. U-21490. In addition, I have filed direct testimony in Case No. U-21387 supporting the tariff exhibit of the Company's proposed voluntary Renewable Natural Gas Program, and Case No. U-21321 supporting the tariff exhibit for the Company's 2024-2025 Energy Waste Reduction Plan.

**Q. What is the purpose of your direct testimony in this proceeding?**

A. The purpose of my direct testimony is to present the Company's proposed tariff language changes to its gas rate schedules.

**Q. Are you sponsoring any exhibits?**

A. Yes, I am sponsoring the following exhibits:

| | | |
|---|---|---|
| Exhibit A-71 (KDH-1) | | Summary of Tariff Changes; and |
| Exhibit A-16 (KDH-2) | Schedule F-5 | Proposed Tariff Sheets (MPSC No.3 Redlined Version). |

**Q. Were these exhibits prepared by you or under your direction?**

A. Yes.

**Q. Please describe Exhibit A-71 (KDH-1) – Summary of Tariff Changes.**

A. Exhibit A-71 (KDH-1) provides a summary and explanation of the tariff changes proposed in this filing to the tariffs in the Company's Gas Rate Book.

**Q. Please describe Exhibit A-16 (KDH-2), Schedule F-5, Proposed Gas Tariff Sheets (MPSC No. 3 Redlined Version).**

A. Exhibit A-16 (KDH-2) Schedule F-5, contains, in redlined format, all proposals the Company is making in this case to its current gas tariffs in the Company's Rate Book for Gas Service (MPSC No. 3 – Gas). Existing tariff language proposed for deletion is indicated by red strikethrough formatting. New tariff language being proposed is indicated

by blue, underline, italicized formatting. Some of these changes are discussed in the testimony of other Company witnesses. For example, the rationale for price changes to the Company's gas rate schedules are supported by the Company's rate design witness, S. Austin Smith.

**Q. Please explain the proposed changes Rule C8.B., Customer Contribution on Tariff Sheet No. C-37.00.**

A. The Company has a winter construction period from December 15 to April 15 in which additional charges based on periodic reviews of actual costs incurred are applicable. The Company's proposed tariff language is adding the ability for the Company to waive winter construction charges, partially or completely, at the Company's discretion for certain projects or sites that allow for efficient construction.

**Q. Please explain the changes on Tariff Sheet No. C-40.00.**

**A.** On Tariff Sheet No. C-40.00, the Company proposes changing the carrying cost rate to 9.11% and the discount rate to 7.35%. This change is further detailed in Company witness Smith's Exhibit A-16 (SAS-2), Schedule F-2.1.

**Q. Please explain the proposed changes to General Service Outdoor Lighting Rate GL on Tariff Sheet Nos D-2.00, D-2.10, D-2.30, D-9.00, and D-14.00.**

A. These tariff sheets reflect the termination of General Service Outdoor Lighting Rate GL (Rate GL). All remaining gas streetlights on Rate GL will have been retired or scheduled for retirement such that no gas streetlights on Rate GL will be in service on and after November 1, 2025. Rate GL has been closed to new business since December 23, 1971, as authorized in Case No. U-3907.

**Q. Please explain the changes on Tariff Sheet Nos. D-9.00, E-13.00, and E-14.00.**

A. These tariff sheets reflect the revision of Transmission Only Transportation Service Rate TOT to four rate options of STT, LTT, XLTT and XXLTT with both a Customer Charge and a Transportation Charge as proposed in direct testimony by Company witness Smith.

Additionally, the Company is proposing to exclude power generation customers from taking Transmission Only Transportation Service Rate TOT. Power generation customers have a different load profile than what was planned for in the Transmission Only Transportation Service Rate TOT.

**Q. Please describe proposed modifications to the Group Transportation Service Pilot Program located on Tariff Sheet Nos. A-6.00, G-1.00 through G-3.00, G-5.00, G-6.00, and G-8.00 through G-11.00.**

A. The Group Transportation Service Pilot Program was authorized in Case No. U-20439 effective for service rendered on and after October 1, 2020. With the initial five-year pilot development timeframe reaching completion, the Company is proposing elimination of the word Pilot from the program name, updating all references to the program to "Group Transportation Service Program" throughout the Company's Gas Rate Book.

**Q. Are there any other tariff changes being proposed by the Company?**

A. Yes. The remainder of the Company's proposed tariff changes are described in Exhibit A-71 (KDH-1), Summary of Tariff Changes. The exhibit provides a summary and explanation of all the tariff changes being proposed by the Company in this case.

**Q. Does this complete your direct testimony?**

A. Yes.

MR. RUSZKIEWICZ: The Company's next witness is Timothy K. Joyce. Based on stipulation of the parties, the Company moves to bind in the testimony of Mr. Joyce. He had direct testimony, cover page, plus 41 pages of prefiled testimony. Mr. Joyce also had rebuttal testimony, which consisted of a cover page and 15 pages of prefiled testimony.

With that, the Company also moves to admit the exhibits of Mr. Joyce, which are marked as A-72, A-73, A-74, A-75, A-12 Schedule B-5.7, A-76, and A-77.

JUDGE VARCHETTI: Are there any objections to the admission of the direct or rebuttal testimony of Mr. Joyce or any of the associated exhibits?

Hearing none, then, the testimony is bound into the record and the exhibits are admitted.

MR. RUSZKIEWICZ: Thank you.

(Direct and Rebuttal Testimony bound in)

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

| | | |
|---|---|---|
| In the matter of the application of<br>**CONSUMERS ENERGY COMPANY**<br>for authority to increase its rates for the<br>distribution of natural gas and for other relief. | )<br>)<br>)<br>)<br>) | Case No. U-21806 |

**DIRECT TESTIMONY**

**OF**

**TIMOTHY K. JOYCE**

**ON BEHALF OF**

**CONSUMERS ENERGY COMPANY**

December 2024

**Q. Please state your name and business address.**

A. My name is Timothy K. Joyce, and my business address is 17000 Croswell Street, West Olive, Michigan 49460.

**Q. By whom are you employed and in what capacity?**

A. I am employed by Consumers Energy Company ("Consumers Energy" or the "Company") as Senior Strategy Manager in the Gas Engineering and Supply Department.

**Q. Please describe your educational background.**

A. In 2000, I received a Bachelor of Science Degree in Mechanical Engineering from Purdue University. In 2014, I received a Master of Business Administration Degree from Grand Valley State University.

**Q. Please describe your business experience.**

A. My professional working career began in 2001 as a Boiler Engineer for Consumers Energy. In this position, I performed boiler inspections and contractor oversight/weld quality during maintenance outages. In 2003, I joined the Operations Department as a Production Engineer at the J.H. Campbell ("Campbell") Plant. In this position, my responsibilities included troubleshooting of equipment, filling in as a shift supervisor and acting as backshift outage manager. In 2007, I accepted a position as Production Lead at Campbell. In this position, my responsibilities included management of day-to-day operations at Campbell Units 1 and 2. In 2008, I moved into a Gas Compression Engineer position for Consumers Energy. My responsibilities included engineering and construction of new compressor stations at White Pigeon Compressor Station ("White Pigeon") Plant 3 and Ray Natural Gas Compressor Station ("Ray") Plant 3.

In 2011, I accepted the position of Project Lead Engineering on the Air Quality Control System project for Campbell Units 1 and 2. This role involved leading the engineering, procurement, installation, and start-up of air emissions reduction equipment on each unit.

In 2016, I moved into my current role of Senior Strategy Manager. In this position, my responsibilities include asset lifecycle oversight, guidance and leadership of the Natural Gas Delivery Plan ("NGDP"), implementation, recovery and verification of results focused on the Company's investment and operation of compression and storage assets.

**Q. Have you testified in other cases before the Michigan Public Service Commission ("MPSC" or the "Commission")?**

A. Yes. I have recently provided testimony in Case No. U-20322, Case No. U-20650, Case No. U-21148, Case No. U-21308, and Case No. U-21490. In these cases, I have provided testimony and exhibits concerning capital investments for the Company's Gas Compression and Gas Storage assets, operating and maintenance costs for the Company's Gas Compression, Lost and Unaccounted for ("LAUF") Gas, Company Use Gas expenses, Storage Field Inventories and Cost of Gas Sold.

**Q. What is the purpose of your direct testimony in this proceeding?**

A. My direct testimony explains the Company's request for rate relief as it relates to the Company's Gas Compression & Storage ("GCS") assets, and I have divided my direct testimony into five parts:

(i) A description of the Company's GCS assets;

(ii) A description of functions within Gas Compression and Gas Storage;

(iii) A description of Operation and Maintenance ("O&M") expenses for Compression, Cost of Gas Sold and Underground, LAUF and Company Use Gas for the years 2023 through the projected test year (November 1, 2025

through October 31, 2026). (**NOTE:** Storage O&M is addressed by Company witness James P. Pnacek);

(iv) A description of GCS capital expenditures (including the Freedom Compressor Station ("Freedom") upgrade project) for the years 2023 through the projected test year (November 1, 2025 through October 31, 2026) base; and

(v) A description of certain Information Technology ("IT") Projects that support gas compression operations.

**Q. Are you sponsoring any exhibits with your direct testimony?**

A. Yes. I am sponsoring the following exhibits:

| | | |
|---|---|---|
| Exhibit A-72 (TKJ-1) | | 12 Months Ending October 31, 2026 Gas Compression and Renewable Natural Gas O&M Expenses; |
| Exhibit A-73 (TKJ-2) | | Summary of Actual & Projected Gas O&M Expenses for Lost and Unaccounted for Gas & Company Use Gas for the Test Year 12 Months Ending October 31, 2026; |
| Exhibit A-74 (TKJ-3) | | Calculation of Gas Loss Percentage August 2019 through July 2024; |
| Exhibit A-75 (TKJ-4) | | Calculation of Allowance for Gas Use and Losses for the Test Year 12 Months Ending October 31, 2026; |
| Exhibit A-12 (TKJ-5) | Schedule B-5.7 | Projected Capital Expenditures Gas Compression and Gas Storage Summary of Actual & Projected Gas Capital Expenditures; |
| Exhibit A-76 (TKJ-6) | | Storage Well Rehabilitation Program Detail; and |
| Exhibit A-77 (TKJ-7) | | Storage Fields Month End Summary. |

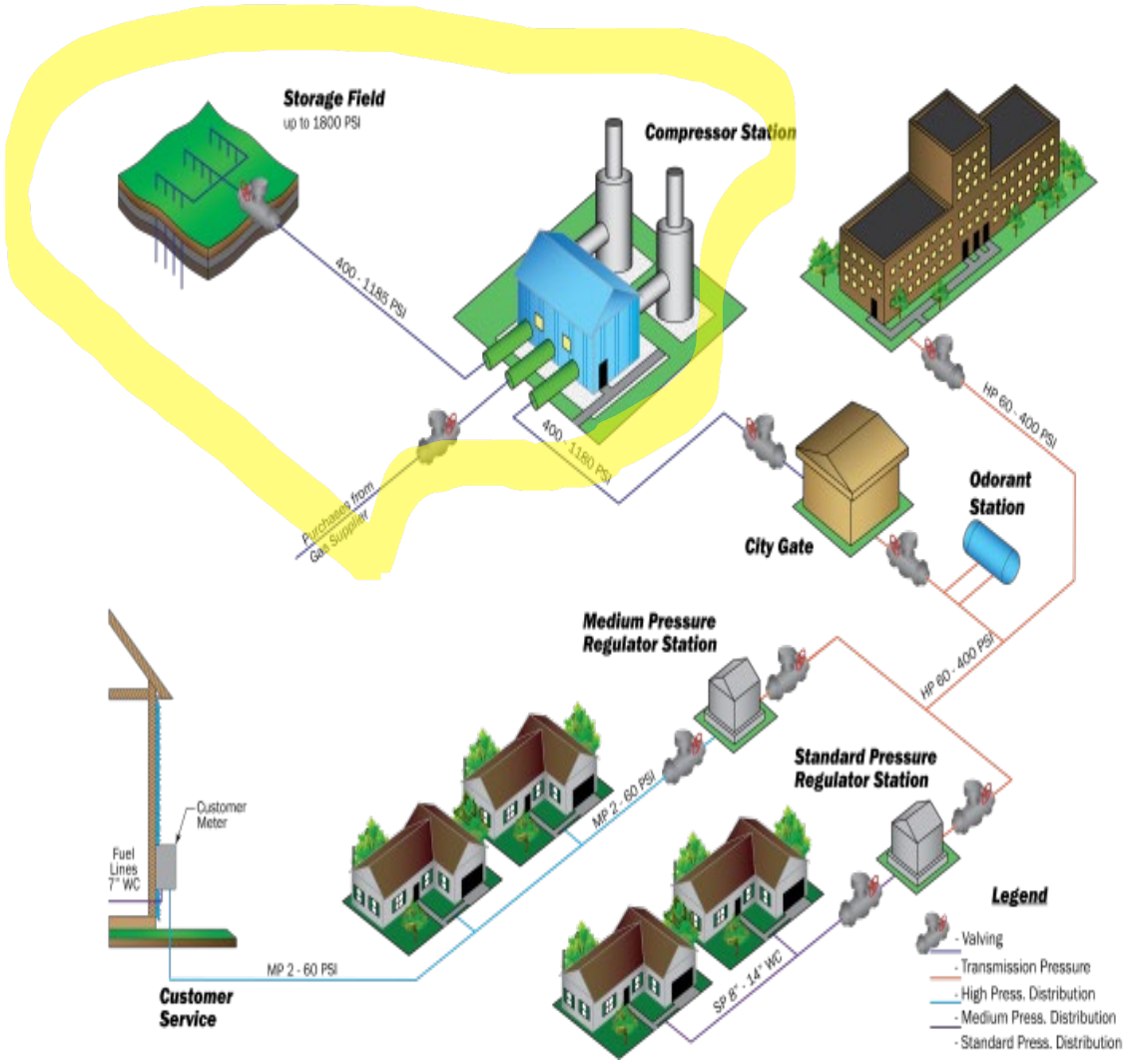
**Q. Were these exhibits prepared or assembled by you or under your direction or supervision?**

A. The exhibits listed above were prepared either by me or under my direction and supervision.

**(i) GCS ASSETS**

**Q. Please provide an overview of the Company's GCS assets.**

A. The Company operates and maintains 8 compressor stations, 15 storage fields, and 808 wells as of January 2024, throughout Michigan's Lower Peninsula. As of October 2024, the compression fleet is comprised of 40 natural gas-fired engines which generate 147,393 Brake Horsepower ("BHP"), providing the pressure necessary to move gas in and out of the storage fields and to receive supply from interstate pipeline sources onto the Company's transmission pipeline system. The transmission pipeline system connects the gas supplies to Consumers Energy's storage fields, gas distribution system, and other customer loads. In the diagram below, the Storage and Compression systems are inside the yellow highlighted section.




The Company's storage fields are used to balance the difference between the incoming system supplies and customer demand on a continuous, real-time basis. The storage fields are naturally occurring porous rock formations that are located deep underground. These rock formations hold natural gas, much like sponges hold water, and have a total working gas volume of 154 BCF. Consumers Energy purchases 100% of the natural gas it provides to customers. Natural gas, which is placed in storage, flows through one or more of the Company's numerous wells. The Company's GCS fleet is comprised of the following:

**Compressor Stations:**

| Name | Location | Number of Units | Horsepower (BHP) |
|---|---|---|---|
| Freedom | Manchester, MI | 5 | 18,750 |
| Muskegon River | Marion, MI | 7 | 27,276 |
| Northville | Northville, MI | 4 | 10,800 |
| Overisel | Hamilton, MI | 4 | 10,800 |
| Ray | Armada, MI | 5 | 23,675 |
| St. Clair | Ira, MI | 6 | 27,282 |
| White Pigeon | White Pigeon, MI | 8 | 27,775 |
| Huron | Sebewaing, MI | 1 | 1,035 |

**Gas Storage Fields:**

| ***Type*** | ***Storage Field Name*** | ***Working Gas Volume (Bcf)**** | ***Base Gas Volume (Bcf)**** | ***Total Gas Volume (Bcf)**** | **Number of Wells** | **Max Field Rate (MMcfd)**** |
|---|---|---|---|---|---|---|
| ***Base*** | **Winterfield** | **25.30** | **47.00** | **72.30** | **249** | **266** |
| | **Overisel** | **25.50** | **27.50** | **53.30** | **152** | **230** |
| | **Salem** | **11.60** | **18.90** | **30.50** | **71** | **130** |
| | **Cranberry** | **11.00** | **17.20** | **28.20** | **129** | **106** |
| | **Riverside** | **1.50** | **7.50** | **9.00** | **51** | **13** |
| ***Intermediate*** | **Hessen** | **13.50** | **3.48** | **16.98** | **24** | **455** |
| | **Puttygut** | **9.50** | **5.10** | **14.60** | **24** | **310** |
| | **Four Corners** | **2.39** | **1.39** | **3.78** | **6** | **68** |
| | **Swan Creek** | **0.42** | **0.23** | **0.65** | **1** | **20** |
| | **Ray** | **48.10** | **17.27** | **65.37** | **62** | **1975** |
| ***Peaker*** | **Ira** | **2.00** | **4.25** | **6.25** | **15** | **480** |
| | **Lyon 29** | **1.23** | **0.95** | **2.18** | **3** | **270** |
| | **Lenox** | **1.20** | **2.03** | **3.23** | **11** | **247** |
| | **Lyon 34** | **0.70** | **0.66** | **1.36** | **5** | **120** |
| | **Northville Reef** | **0.50** | **0.72** | **1.22** | **5** | **210** |
| ***NOTE:** All gas volumes are in MMcf at 14.73 psi dry pressure base. | | | | | | |
| ****NOTE:** Max Field Rate is the maximum capability at full inventory and pressure and would decline over the withdrawal season and depend on the final inventory level at the beginning of withdrawal. | | | | | | |

**(ii) GAS COMPRESSION AND STORAGE**

**Gas Compression**

**Q. Please describe the primary functions of gas compression.**

A. Gas compression is responsible for the safe operation, maintenance, and performance of the Company's natural gas-fired engines. These units provide the pressure necessary to move gas in and out of the storage fields, to move gas from interstate pipeline sources onto the Company's transmission pipeline system, and ultimately, to move the natural gas to the city gate facilities feeding distribution systems that transport gas to the Company's customers.

**Q. Do maintenance costs vary by individual compression engine(s)?**

A. Yes, maintenance costs vary by individual compression engine(s). The Company's compression engines vary in age, size, type, and design and encounter varying operating conditions.

**Q. Is it common to have size, type, design, and operating differences?**

A. Yes. Consumers Energy is not unique in that its fleet contains units of different size, type, and design. The compression engines used for storage will typically encounter a wider range of operating pressures and flow rates than engines used to boost pressure on the transmission system.

**Q. Please describe the work completed in a natural gas compressor engine maintenance inspection.**

A. The frequency of compressor engine inspections is based on operating hours, and consists of disassembling, inspecting, and cleaning the different components of the engine. During the inspection, worn or damaged parts are repaired or replaced to specific tolerances. Cost

can range from $25,000 to $75,000 per inspection, depending on the size and model of the unit. Additional costs can occur if parts are found to be worn and require replacement before resulting in random outages at inopportune times when needed to meet system demand.

**Q. How does Consumers Energy measure the success of its Gas Compressor Engine Maintenance Program?**

A. The Company measures Random Outage Rate ("ROR") to measure engine/compressor performance. ROR is the percentage of time a unit is unavailable for unplanned reasons.

**Q. What is the Company's current ROR, and how does it compare to previous years?**

A. The table below shows the Company's ROR from 2020 through September 2024.

Table 1: System ROR

| Year | System ROR |
|---|---|
| 2020 | 17.5% |
| 2021 | 15.6% |
| 2022 | 8.4% |
| 2023 | 11.6% |
| 2024 (YTD Sept) | 19.2% |

Table 2: Freedom, Ray and White Pigeon Station ROR

| Year | Freedom Station ROR | Ray Station ROR | White Pigeon Station ROR |
|---|---|---|---|
| 2019 | 21.8% | 38.2% | 21.5% |
| 2020 | 21.7% | 17.7% | 25.5% |
| 2021 | 27.0% | 16.5% | 25.1% |
| 2022 | 13.2% | 10.6% | 9.2% |
| 2023 | 11.7% | 15.9% | 4.3% |
| 2024 (YTD Sept) | 15.1% | 9.1% | 6.1% |

**Q. What has contributed to the improved ROR performance in 2023-24 in Table 2 and what is needed for the Company to be able to achieve and maintain its engine performance?**

A. The Freedom upgrade project is completed, and all legacy horsepower have now been removed from service, as detailed later in my testimony. Retirement of units at White Pigeon and Ray occurred in 2021. The effort to optimize the compression fleet has provided improved performance of the newer units and removal of the lower performing legacy units, which has netted an improvement in ROR for 2023-24.

To improve the ROR of the remaining compression fleet and, consequently, reduce downtime and overall maintenance costs, the Company will enhance maintenance plans and practices to achieve more efficient preventative programs and eliminate costly reactive events.

**Q. Please describe the Company's objectives for gas compression assets.**

A. The Company's objective for its gas compression assets is to realize the most value out of the Company's substantial storage capacity in terms of resilience and buffering summer/winter price fluctuations. Continually improving the safety of compression assets and reducing operational risks is critical. Beginning in 2010, the Company made significant progress transforming the compression fleet from 1950s technology to modern, efficient, and clean running equipment. The Company's objectives for Compression of improving the system's reliability, resiliency and optimal utilization are:

a. Accelerate the implementation of preventative maintenance program and practices, and gradually implement predictive technologies.

b. Decommission retired/mothballed compressor units.

c. Optimize the fleet of compressor units at Muskegon River to meet volume and pressure requirements.

d. Evaluate contingency options for resiliency and opportunities that mitigate risk of outages at the compression stations.

e. Assess feasibility of retiring additional compression assets to focus investment on most critical units and optimize portfolio.

f. Compressor Station Compliance with Proposed Michigan NOx RACT Rule.

**Q. Does the NGDP discuss gas compression assets?**

A. Yes, gas compression is addressed in Section IV of the Company's NGDP, which is provided as Exhibit A-42 (NPD-1) by Company witness Neal P. Dreisig.

**Gas Storage**

**Q. Please describe the primary functions of Gas Storage Engineering.**

A. Gas Storage Engineering has responsibility for the integrity, maintenance, and performance of the Company's 15 storage fields and 808 wells. This includes storage well maintenance and well logging and compliance with well integrity regulations. Further details about Gas Storage Engineering O&M expenses are included in Company witness Kristine A. Pascarello's testimony.

**Q. Please provide further insight into well maintenance.**

A. Well maintenance is comprised of many different programs and has been the topic of media attention in recent years with the Aliso Canyon event. Well logging is one of the primary components of well maintenance. *Well logging* is an industry term that describes a method used to help assess storage well integrity. Storage well integrity is a critical component to ensuring public safety.

**Q. Please provide more detail on well logging.**

A. Well logging includes the use of gamma ray-neutron log for identification of gas accumulation behind casings, corrosion logs for internal and external casing corrosion, and cement bond logs to assess integrity of cement between the casing, surrounding rock, or additional casings. Additionally, well rehabilitation work is performed in conjunction with well logging to mitigate the formation of skin damage. *Skin damage* is a term used to describe the reduction in the ability of the reservoir rock to store and deliver gas. Rehabilitation removes solids, scale build-up, and compressor oils in the well that accumulated during the normal process of injecting and withdrawing gas from storage. By removing this build-up, the gas moves more efficiently and reduces the risk of moving debris into the compressors, thereby increasing safety and extending the life of the assets.

**Q. Do storage well integrity regulations currently exist?**

A. Yes. On December 19, 2016, the Department of Transportation's Pipeline and Hazardous Materials Safety Administration ("PHMSA") published in the Federal Register an interim final rule ("IFR") that revises the federal pipeline safety regulations to address critical safety issues related to downhole facilities, including wells, wellbore tubing, and casing, at underground natural gas storage facilities. This IFR was in response to the June 22, 2016, enactment of the Protecting our Infrastructure of Pipelines and Enhancing Safety ("PIPES") Act of 2016 that included a requirement for PHMSA to set federal minimum safety standards for underground natural gas storage facilities. Requirements included in the IFR were amended to final rule by PHMSA on February 12, 2020.

**Q. Did PHMSA set federal minimum safety standards?**

A. Yes. PHMSA published the underground natural gas storage facilities rule (49 Code of Federal Regulations ("CFR") 192.12) which incorporates by reference the requirements within the American Petroleum Institute ("API") Recommended Practice ("RP") 1171.

**Q. Is Consumers Energy compliant with the standards set forth in 49 CFR 192.12?**

A. Yes. Consumers Energy has reviewed the requirements outlined in 49 CFR 192.12 and the applicable API RP 1171. The Company developed procedures governing operations, maintenance, integrity demonstration and verification, monitoring, threat and hazard identification, assessment, remediation, site security, emergency response and preparedness, and recordkeeping consistent with the requirements of API RP 1171, sections 8, 9, 10, and 11 by January 18, 2018, for all existing underground natural gas storage facilities. Integrity assessments of the underground storage wells began in 2017 to support the anticipated compliance timeframe, for completing all risk management activities as required in API RP 1171. The compliance date has now been set for March 2027.

**Q. Has PHMSA performed an audit of the Company storage system?**

A. Yes. In May 2019, PHMSA performed a program overview audit, followed by field audits, on six gas storage fields and the associated site-specific programs. The audit focused on Sections 8 through 11 of API RP 1171. In 2020, there were field specific audits at the Four Corners, Swan Creek, Hessen, Ira, and Puttygut fields. In 2021, the MPSC jointly with the Michigan Department of Environment, Great Lakes, and Energy performed field specific audits at the Riverside, Lyon 34, Lyon 29, and Northville Reef.

**Q. What was the result of the 2019 audits?**

A. The Company created a Detailed Action Plan based on PHMSA recommendations of best industry practice. Topics outlined in the plan include: Risk Management for Gas Storage Operations, Integrity Demonstration, Verification, Monitoring Practices, Site Security and Safety, Site Inspections, Emergency Preparedness and Response, and Procedures and Training.

**Q. Were any changes made to the Well Rehabilitation Program based on the PHMSA 2019 audit recommendations?**

A. Yes. PHMSA recommended the wells in the Riverside field be addressed by the program (risk priority as identified in the risk analysis) until the plan to discontinue operation of the field is executed. As a result, the Company added wells to the 2019 and future-year Well Rehabilitation Program work scopes. PHMSA also recommended the addition of annular piping to surface where casing pressures will be recorded and monitored, as per the requirement in API RP 1171. These items are now being addressed by the program as they are encountered, which has an impact on the average cost per well. The Company established a new annulus pressure monitoring program for 2022 and future years to address compliance, including the wells already rehabilitated in 2017 and 2018.

**Q. Have there been any additional audits performed on the Company storage system?**

A. Yes. In 2023, an audit of the Company's SIMP program was conducted by the MPSC and EGLE. The scope of the audit included Procedures, Records, and Field Observations for Salem, Overisel, Ray, Lenox, Cranberry Lake, and Winterfield Storage Fields. At the conclusion of the audits, the company did not receive any enforcement or non-compliances and received 16 recommendations that were primarily procedural in nature and did not impact the funding required for the current test year.

**Q. Is the Company projecting O&M expenses related to well logging in this case?**

A. Yes. Well logging O&M expenses are sponsored by Company witness Pascarello in the well re-assessment section.

**Q. Does gas storage have additional responsibilities?**

A. Yes, gas storage is also responsible for the gas storage field inventory verification process.

**Q. Please describe the gas storage field inventory verification process.**

A. As a prudent operating practice and following the regulatory requirements of API RP 1171 as referenced in 49 CFR 192.12, Consumers Energy performs storage field pressure surveys at the conclusion of each injection cycle (usually August through November), and each withdrawal cycle (usually March through June). Storage well pressures are collected, the average field pressure is determined, and the results are plotted against the metered volumes. Plotting storage field pressure and inventory data provides a means of monitoring and trending storage field performance over time. It is through this process that the inventory balances at the storage fields are identified for adjustment.

**Q. Why is the performance of storage field inventory verification a prudent practice?**

A. Verification of storage field inventory after each injection and withdrawal cycle provides important data used to monitor the current condition of the storage reservoir. In addition, storage field inventory verification provides a means of determining flow meter measurement accuracy, and whether losses between the transmission and storage systems may be occurring as a result of valve leakage. Without inventory verification, there is the potential for gas to have migrated out of the storage reservoir, which would pose potential risk to public safety. In addition, if inventory is not verified and a leakage were to occur unknowingly, customers could be at risk of paying for gas that is lost.

**Q. What are the recent results from the gas storage inventory verification process?**

A. The storage fields have experienced deviations from the accounting booked figures. The Company typically adjusts gas storage inventory based on a deviation occurring for three consecutive years (considered long-term). Routine changes in operating parameters during a given injection or withdrawal season may cause short-term storage field pressure variations. These short-term pressure variations may cause the natural gas to migrate deeper into the reservoir rock formation, temporarily impacting the inventory survey results. Company personnel have investigated the integrity of these fields and believe most of the inventory adjustment is attributed to metering accuracy limitations or valves not sealing properly. The storage field inventory adjustment is shown in Exhibit A-74 (TKJ-3).

**Q. Why does the storage inventory deviation occur?**

A. A common cause of the deviations and subsequent storage field inventory adjustments can be valves not sealing properly. As part of the pressure survey work each spring and fall, the sealing capability of the valves used to isolate the storage field are inspected. The primary cause of valve leakage, as with the field meter, is debris affecting the sealing mechanisms in the valves. In addition, the electrical or hydraulic mechanical operators used to open and close the valves can go out of alignment, not allowing the valve to fully close. When storage field isolation valves are found to be not sealing, the valves are adjusted or repaired.

**Q. Please describe the Company's objectives for gas storage assets.**

A. The gas storage system today includes 15 storage fields totaling approximately 154 billion cubic feet of working gas storage capacity. Storage assets play an important role in customer affordability, enabling the purchase and storage of gas when prices are lower,

and delivery of that gas in the winter. On average, storage has supplied approximately 50% of customer gas deliveries during winter (November through March) and up to approximately 80% on peak days. Storage also allows Consumers Energy to store or withdraw gas throughout the day to reconcile the difference between customer demand and the fixed pipeline supply.

As part of the NGDP (and in view of the PHMSA Storage Audit based on API RP 1171), the Company ran an initial assessment on four of the low-cyclic fields with the results showing the need to consider the retirement of at least one storage field at this time. Based on the outcome of this initial assessment, Consumers Energy has evaluated retirement and optimization of its storage fields over time based on certain factors like customer load, market price changes over time, increasing operating costs, reliability, and total cost to customers. The Company has made the decision to move forward with the sale of Riverside storage field; further details and projected expenses are outlined later in my testimony. With the remaining storage portfolio, Consumers Energy will remain focused on reliable operation, increasing resiliency, while optimizing deliverability.

**Q. Does the NGDP discuss gas storage assets?**

A. Yes. Gas storage is addressed in Section IV of the Company's NGDP, which is provided as Exhibit A-42 (NPD-1) by Company witness Dreisig.

**Q. What value do customers receive from the Company's GCS assets?**

A. GCS assets support the Company's ability to ensure adequate supplies of natural gas are available for customers when needed. They are also an important foundation to maintaining affordable prices, as they allow the Company to take advantage of favorable seasonal market conditions, while procuring adequate supplies in advance to meet

customers' needs. Finally, storage fields are critical to mitigating winter price cycles, summer outage schedules, and maintaining supply during unexpected supply interruptions.

**(iii) O&M EXPENSES FOR COMPRESSION, COST OF GAS, LOST AND UNACCOUNTED FOR AND COMPANY USE**

**Q. Please describe Exhibit A-72 (TKJ-1).**

A. Exhibit A-72 (TKJ-1) identifies the 12 Months Ending October 31, 2026, Gas Compression and Renewable Natural Gas O&M Expenses. Specifically:

- Page 2, column (a) identifies each O&M expense category;
- Page 2, column (b) identifies the Actual 2023 Gas Compression O&M expense as $17,880,000;
- Page 2, column (c) identifies the Projected 2024 Gas Compression O&M expense as $17,030,000;
- Page 2, column (d) identifies the Projected 2025 Gas Compression O&M expense as $16,590,000; and
- Page 2, column (e) identifies the Projected test year Gas Compression O&M expense as $17,577,000.

**Table 3: Compression O&M**

| | Projected O&M Expenses | | | | |
|---|---|---|---|---|---|
| | (a) | (b) | (c) | (d) | (e) |
| | | | Projected | | |
| Line No. | Description | 12 mos. Ended 12/31/2023 | 12 mos. Ending 12/31/2024 | 12 mos. Ending 12/31/2025 | 12 mos. Ending 10/31/2026 |
| 1 | Gas Compression | 18,695 | 17,030 | 16,590 | 17,577 |
| 2 | Compression Rebuilds | (815) | - | - | - |
| 4 | Renewable Natural Gas | - | - | - | - |
| 5 | TOTAL O&M | $ 17,880 | $ 17,030 | $ 16,590 | $ 17,577 |

**Q. Please discuss the 2023 Actual O&M expenses incurred by the Company for Gas Compression.**

A. The 2023 Actual O&M expenses were taken from Consumers Energy's internal accounting records.

**Q. Please explain how the 2024, 2025, and projected test year O&M expenses were calculated.**

A. Consumers Energy tracks the history and future maintenance needs of each station. Once costs to reliably operate and comply with the Michigan Gas Safety Code are prioritized, Business Services-Portfolio Planning, with the support and input from Engineering and Asset Strategy, evaluates the maintenance plans required to maintain and improve the condition of the plant. Using this information, a preliminary plan is prepared, reviewed (to ensure high-priority issues are addressed and adequate resources and funding are available), and approved by management. The overall objective is the safe, reliable, and cost-effective operation of the Compression operations.

O&M costs projected in Exhibit A-72 (TKJ-1) were developed by evaluating a station's operating history and are broken into two categories: "labor" and "non-labor." Labor is the primary component and has a predictable increase. Non-labor expenses are also predictable and include items required to operate and execute a workplan to meet code requirements, while meeting operational performance to fulfill customer demand. These items include, but are not limited to: (i) fuel, oil and glycol for equipment and vehicles; (ii) materials; (iii) tools; (iv) cleaning supplies; (v) security; and (vi) road and grounds maintenance. Please note that Gas Storage Operations expenses are addressed by Company

witness Pnacek. The test year spending was calculated using recent historical monthly actuals information.

**Q. Please explain page 4 of Exhibit A-72 (TKJ-1).**

A. Exhibit A-72 (TKJ-1) presents the amounts of the O&M expenses by applying either an inflation rate or a merit increase rate, or both to historical O&M expense. Column (b) shows the historical O&M expense. Column (c) shows the amount of the historical when an inflation rate or merit increase rate is applied to it. Columns (e) and (g) show the amounts when an inflation rate or merit increase rate is applied for each bridge period, respectively. Columns (d), (f), and (h) show the merit and inflation amounts for each respective period. Amounts that were projected using other methods are included in column (i). Column (j) is the projected test year O&M and is the sum of columns (b), (d), (f), (h), and (i); column (j) is aligned with the Company's projected expenses for each sub-program for the test year, as shown in Exhibit A-72 (TKJ-1). Therefore, column (i) represents the increase in O&M expenses that is not due to inflation; in other words, this represents where O&M expenses are changing due to some other factor than inflation.

**Q. Are there any Employee Incentive Compensation Program ("EICP") O&M expense dollars included in your exhibits?**

A. No, there are not. The direct testimony and exhibits of Company witness Amy M. Conrad contain the Gas Transmission and Distribution EICP O&M expense dollars.

**Q. Please explain why the projected test year O&M expenses proposed in Exhibit A-72 (TKJ-1) are reasonable.**

A. This level of O&M expense allows the Company to provide reliable service by operating and maintaining its Compression equipment to move gas into and out of storage and throughout its system to meet the needs of customers.

## COST OF GAS AND COST OF GAS STORED UNDERGROUND

**Q. Please describe Exhibit A-77 (TKJ-7).**

A. Exhibit A-77 (TKJ-7) is a forecast of the Company's September 2024 through October 2026 underground gas storage volumes and dollars.

**Q. Would you briefly explain the background for Exhibit A-77 (TKJ-7)?**

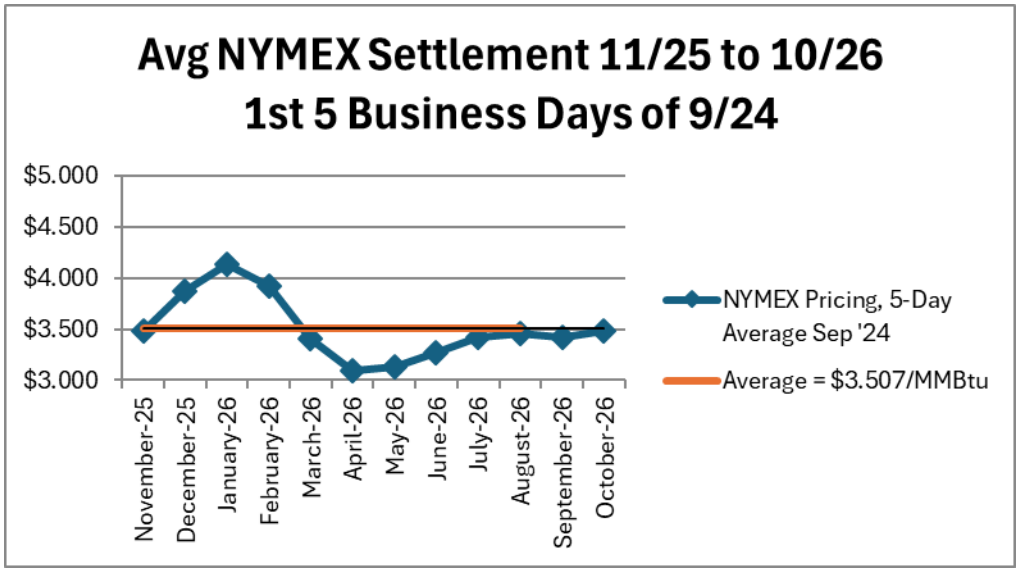
A. Yes. Exhibit A-77 (TKJ-7) reflects the end of the month underground gas storage volumes and dollars that result from the Company's natural gas purchases for its Gas Cost Recovery ("GCR") and Gas Customer Choice ("GCC") customers. The costs and volumes reflect the Company's existing supply and transportation contracts for the historical period, as well as those of the GCC suppliers. Projected supply sources and prices are used for the future periods.

**Q. What is the Company's projected test year 13-month average volume and cost of gas in storage, as set forth on Exhibit A-77 (TKJ-7)?**

A. Through October 2026, the Company is projecting a 13-month average cost of gas in storage of $2.949/Mcf ($382,035,501/129,554,050 Mcf).

**Q. What gas prices were assumed for November 2025 through October 2026 in developing your Exhibit A-77 (TKJ-7)?**

A. The average New York Mercantile Exchange ("NYMEX") settlement prices for November 2025 through October 2026, as of the first five business days of September 2024, were used. These NYMEX natural gas prices, as shown in the graph below, averaged $3.507/MMBtu for November 2025 through October 2026.




For the November 2025 through October 2026 GCR requirements (197,455,189 Mcf), 0% has been purchased at a fixed price, therefore 100% of the GCR requirements would be subject to the NYMEX average.

**Q. What is the Company's projected average cost of gas sold for October 2025 through September 2026?**

A. The Company is projecting an average cost of gas sold for November 2025 through October 2026 of $3.296/Mcf ($754,273,924/228,868,416 Mcf). The Company's cost of gas sold reflects locational pricing differences between NYMEX (Henry Hub) and other supply locations (basis), transportation costs, unused reservation charges, and the GCR

accounting treatment of net system uses. The projected average cost of gas sold is determined by including the costs and volumes associated with purchase requirements and net storage activity during the period, and thus reflects the same variables and assumptions relied on to calculate ending inventory values.

**Q. Please provide additional detail about the average cost of gas sold and cost of gas stored underground.**

A. Both the average cost of gas sold and cost of gas stored underground reflect the natural gas supply and transportation contracts in place within the historic period for GCR and GCC supply. The Company's existing supply and transportation contracts are planned to leverage storage and system investments in today's gas market to provide customers with safe, reliable, and affordable natural gas service pursuant to the Company's NGDP.

The cost of gas stored underground is used within the Company's projected test year working capital included in Company witness Heather L. Rayl's Exhibit A-12 (HLR-34), Schedule B-4. The average cost of gas sold of $3.296/Mcf is used in the calculation of the Company's revenue requirement and to price out Company Use and LAUF gas volumes supported later in my testimony.

**LAUF Gas**

**Q. Please explain LAUF gas as shown on Exhibit A-73 (TKJ-2), line 1, column (b).**

A. LAUF gas is the loss or gain of gas volumes calculated as the difference between the volumes delivered into the transmission and distribution system less the volumes delivered out of those systems. Factors such as gas leaks, customer billing issues, customer theft, meter and measurement accuracy, and gas vented for operational, maintenance, and safety purposes all contribute to the causes of LAUF gas volumes.

**Q. Please describe the LAUF expenses that are projected for the test year.**

A. The test year expenses related for LAUF gas are calculated based on a five-year average of actual LAUF volumes multiplied by the Company's projected commodity cost of gas. Projected LAUF expenses can be found on Exhibit A-73 (TKJ-2). As shown on that exhibit (line 1, column (c)), the test year projected LAUF expense level is $12,709,000. The 2023 historical year amount was $21,116,000 as shown in Exhibit A-73 (TKJ-2), (line 1, column (b)).

**Q. Please explain Exhibit A-73 (TKJ-2).**

A. This exhibit identifies the projected changes from the historical 2023 amount for LAUF expenses to the test year period. The test year LAUF amount was calculated using the methodology consistent with the July 31, 2017 Order in Case No. U-20322, updated with the most recent five-year average Gas Loss percentage and expected test year cost of gas expense, as provided earlier in my direct testimony. Additionally, this exhibit contains the Company Use Gas projected expenses for the test year. Company Use Gas will be discussed later in my direct testimony.

**Q. Please explain Exhibit A-74 (TKJ-3).**

A. This exhibit demonstrates the calculation of the most recent five-year average Gas Loss percentage (line 6, column (g)) of 1.79%. This percentage, when applied to test year throughput levels, determines the expected LAUF and Company Use Gas volumes during the test year.

**Q. Please explain Exhibit A-75 (TKJ-4).**

A. This exhibit shows the calculation of the projected test year amount of LAUF expense (line 14, column (h)) with the methodology adopted in Case No. U-20322. The test year

throughput level and the updated Gas Loss percentage previously discussed have both been used to determine LAUF volumes and the associated expense levels. In addition, as shown on line 11, the Allowance for Use and Losses percentage, also known as the Gas-in-Kind ("GIK") percentage, has been updated to reflect test year projections of 2.57%.

**Q. Is the level of LAUF expense the Company is requesting reasonable?**

A. Yes. The Gas Loss average is based on actual losses on the gas transmission and distribution system over the past five years. The MPSC has consistently recognized a five-year average of Gas Losses to set LAUF volumes, and the Company continues to use that same methodology, updated to reflect the most recent data.

**Q. Why have you included the net storage inventory adjustments in the LAUF figures as noted on Exhibit A-74 (TKJ-3)?**

A. In Case Nos. U-18124 and U-20322, the Commission approved inclusion of storage inventory adjustments in the period in which they are recognized by the Company, within the five-year line loss calculation.

**Q. How does the Company determine its storage inventory adjustments?**

A. The Company's storage inventory adjustments are determined through the gas storage field inventory verification process. This process is described in the *Gas Storage* section of my direct testimony.

**Q. What specific actions does the Company take to monitor and mitigate LAUF gas?**

A. The Company has ongoing actions to monitor and reduce LAUF gas. Some of these actions include:

- A gas measurement team that primarily focuses on assuring (i) measurement accuracy and (ii) that industry practices are maintained relative to LAUF related issues. Company personnel actively participate on the American Gas

Association Transmission Measurement Committees, discussing various measurement issues;

- Measurement personnel audit and witness other Company and third-party personnel performing the regularly scheduled calibration/inspection of metering and gas quality equipment around the state. This helps ensure valid measurements and relevant procedures are followed, and also allows for identification and subsequent correction of any equipment/calibrations/ inspection-related issues;

- The Company utilizes a gas measurement system called Flow Cal monitored by the gas measurement team and field personnel to validate actual measured flows captured by the Company's data acquisition system—known as Supervisory Control and Data Acquisition; and

- The Company reviews compressor stations and high flow city gates for fugitive leaks through the use of infrared cameras and high flow analyzers. Identified leaks will be prioritized and repaired, reducing LAUF gas at those sites.

**Company Use Gas**

**Q. Please describe the Company Use Gas expenses shown on Exhibit A-73 (TKJ-2), line 2.**

A. These expenses are for the natural gas fuel used to run the compression and other equipment used on the transmission and storage system. The largest single use is for fueling the engines at the compressor stations and the gas heaters at the city gate stations. The total cost of fuel gas used is reduced by credits received from transportation suppliers. These suppliers provide GIK to Consumers Energy based on a percentage of their deliveries into the system. Company Use Gas also includes volumes of gas vented or otherwise released for which the Company has knowledge and which the Company has written off.

**Q. What level of expense for Company Use Gas are you proposing in this case?**

A. As set forth on Exhibit A-73 (TKJ-2), line 2, column (c), the Company Use Gas expense for the test year is projected to be $5,502,000. The calculation supporting this value can be found on Exhibit A-75 (TKJ-4).

**Q. Why is there variability in the test year amounts for LAUF and Company Use Gas from the 2023 actual amounts?**

A. In Case No. U-18124, the Commission ordered the Company to apply GIK transportation volume offsets to LAUF and Company Use Gas volumes on a percentage basis based upon the program volumes. The Company has historically offset only Company Use Gas volumes with GIK volumes, and its accounting system is currently configured to record GIK volumes against Company Use Gas volumes. Thus, the 2023 amounts are shown as recorded in the Company's internal accounting records. The test year amounts are reflective of the methodology directed in Case No. U-18124.

**(iv) GCS CAPITAL EXPENDITURES**

**Q. What are the major drivers in determining capital expenditures for GCS?**

A. The Company has made significant investments in upgrades for improved system reliability, deliverability, system integrity, safety, and customer service. These investments, including the Freedom upgrade, allow the Company to fully use its compression and storage facilities to provide continuous reliable service to customers.

**Q. Please describe Exhibit A-12 (TKJ-5), Schedule B-5.7.**

A. This exhibit presents the capital expenditures for GCS from the year 2023 through the projected test year. The expenditures are grouped on page 2 by: Freedom upgrade, Compression Sites, Storage Fields, Storage New Wells (line 14), Well Rehabilitation (line 15), Storage Pipeline Replacement (line 16), Well Data Acquisition (line 17), Riverside Field Retirement (line 18), and Safety Valve Installation (line 19).

**Q. What is the Company's projected level of capital spending?**

A. The Company's rate relief request in this case reflects capital spending on projects for its gas compression and storage sites of $113.0 million for 2023 (Actual), $175.3 million for the 12 months ending December 31, 2024 (Projected), $184.1 million for the 10 months ending October 30, 2025 (Projected), $359.4 million for the 22 months ending October 31, 2025 (Projected), and $162.0 million for the 12 months ending October 31, 2026 (Projected Test Year). The table below, from page 1 of Exhibit A-12 (TKJ-5), Schedule B-5.7, shows the Compression and Storage capital expenditures I am sponsoring in this docket.

**Table 4: Compression and Storage Capital Expenditures ($000's)**

| | (a) | (b) | (c) | (d) | (e) | (f) |
|---|---|---|---|---|---|---|
| | | Historical Year | Projected Bridge Period | | | Projected Test Year |
| Line | | 12 Mos Ended | 12 Mos Ended | 10 Mos Ending | 22 Mos Ending | 12 Mos Ending |
| No | Description | 12/31/2023 | 12/31/2024 | 10/31/2025 | 10/31/2025 | 10/31/2026 |
| 1 | Freedom Upgrade Project | 8,413 | 726 | 0 | 726 | 0 |
| 2 | Compression | 39,197 | 62,267 | 44,597 | 106,864 | 66,198 |
| 3 | Storage | 6,765 | 28,548 | 35,690 | 64,238 | 25,234 |
| 4 | New Well | 11,403 | 17,202 | 28,004 | 45,205 | 32,296 |
| 5 | Well Rehabilitation | 31,031 | 23,681 | 22,341 | 46,022 | 7,498 |
| 6 | Storage Pipeline Replacement | 3,550 | 14,836 | 24,398 | 39,233 | 20,930 |
| 7 | Well Data Acquisition | 239 | 203 | 3,671 | 3,875 | 4,568 |
| 8 | Riverside Field Retirement | 12,449 | 25,439 | 23,756 | 49,195 | 3,504 |
| 9 | Safety Valve Installation | 0 | 2,438 | 1,599 | 4,037 | 1,811 |
| 10 | Total Capital Expenditures | 113,046 | 175,339 | 184,056 | 359,395 | 162,039 |

**Q. Please identify the capital expenditures projected for the Freedom Compression Station.**

A. Exhibit A-12 (TKJ-5), Schedule B-5.7, page 2, lines 1 and 2, identify the total capital expenditures for the Freedom Compression Station. The expenditures identified on line 1 are for the Freedom upgrade project. The details of the Freedom upgrade project are described later in my direct testimony. The expenditures on line 2 are for projects that are separate from the upgrade project. In 2023, costs were incurred for the upgrade project.

In 2024 through 2026, costs will be incurred for the completion of the upgrade project and controller module updates that will improve engine operational stability and reliability.

**Q. Please identify the capital expenditures projected for the Muskegon River Compression Station.**

A. Exhibit A-12 (TKJ-5), Schedule B-5.7, page 2, line 3, identifies the total capital expenditures for the Muskegon River Compression Station. In 2023, costs were incurred for fire gate valve replacements, replacement of dehydration system piping and installation of a glycol charcoal filter system, and installation of new plant air compressors. In 2024 through 2026, examples of projected costs include: gas valve replacements, an H-10 unit overhaul to address engine/compressor condition and performance, and a closed-loop cooling project that will eliminate the need to use Muskegon River water for equipment cooling and to further comply with 2026 EGLE discharge water temperature specifications.

**Q. Please identify the capital expenditures projected for the Northville Compression Station.**

A. Exhibit A-12 (TKJ-5), Schedule B-5.7, page 2, line 4, identifies the total capital expenditures for the Northville Compression Station. In 2023, costs were incurred for the completion of electrical system upgrade, and fire gate valve replacements. In 2024 through 2026, examples of projected costs include: engine controls upgrades, replacement of engine jacket water coolers and air compressor replacement which all support the safe, reliable, and compliant operation of the station.

**Q. Please identify the capital expenditures projected for the Overisel Compression Station.**

A. Exhibit A-12 (TKJ-5), Schedule B-5.7, page 2, line 5, identifies the total capital expenditures for the Overisel Compression Station. In 2023, the Company incurred costs for station control upgrades, valve replacements, and the unitized cooling project. In 2024 through 2026, examples of projected costs include: unitized cooling installation, station control upgrades, Salem field heater replacement, lube oil extractor installation and engine exhaust emissions controls, projects that allow for complete and timely withdrawal of gas from the storage fields and allow the engines to meet new Michigan NOx Reasonably Available Control Technology ("RACT") Rules emission requirements.

**Q. Please identify the capital expenditures projected for the Ray Compression Station.**

A. Exhibit A-12 (TKJ-5), Schedule B-5.7, page 2, line 6, identifies the total capital expenditures for the Ray facility. In 2023, the Company incurred costs for air compressor system upgrades. In 2024 through 2026, examples of projected costs include: valve replacements, air compressor system upgrades, and piping support restoration. These projects will ensure the complete and timely withdrawal of gas from the storage fields.

**Q. Please identify the capital expenditures projected for the St. Clair Compression Station.**

A. Exhibit A-12 (TKJ-5), Schedule B-5.7, page 2, line 7, identifies the total capital expenditures for the St. Clair Compression Station. In 2023, the Company incurred costs for engine controller replacements. In 2024 through 2026, examples of projected costs include turbine gas cooler replacement, dehydration system thermal oxidizer replacement

and gas blowdown vent stack replacement. These projects will ensure the complete and timely withdrawal of gas from the storage fields and safe gas blowdown when required.

**Q. Please identity the capital expenditures projected for White Pigeon.**

A. Exhibit A-12 (TKJ-5), Schedule B-5.7, page 2, line 8, identifies the total capital expenditures for White Pigeon. In 2023, the Company incurred costs for lube oil extractor installation project close out. In 2024 through 2026, examples of projected costs include air compressor replacements, turbine installation and a solar battery installation that is a green project that will reduce cost of electricity for the site.

**Q. Please identify the capital expenditures projected for the Marion Storage Fields (Winterfield, Cranberry Lake and Riverside).**

A. Exhibit A-12 (TKJ-5), Schedule B-5.7, page 2, line 9, identifies the total capital expenditures for the Marion Storage Fields. In 2023 through 2025, the projected costs include the retirement of the Marion City Gate, which is fed from the Winterfield storage field. The retirement is made possible by the completion of the Riverside distribution piping project, which will be tied into to re-feeding customers in Marion, MI. This project will reduce operational cost, gas conditioning difficulties and operational limitations of an operating city gate fed from a storage field. An itemized list of project costs used to create Exhibit A-12 (TKJ-5), Schedule B-5.7 is included in WP-TKJ-6. A breakdown of well rehabilitation work scope is included in Exhibit A-76 (TKJ-6).

**Q. Please provide more detail about future operation of the Riverside storage field.**

A. The Riverside storage field has low working gas capacity, the largest well count compared to other Company gas storage fields with similar working gas volumes, and native hydrogen sulfide, which is flammable and lethal at high concentrations, that has caused it

to be identified as high-risk within gas storage. The Riverside gas storage field is connected directly to three city gates which limits the withdrawal volume from the field and the ability to take outages for maintenance or capital projects and the ability to increase capacity at McBain City Gate. The integrity of the mainline and laterals that support the field are degrading, in some cases causing pressure derates. For these reasons, the Company has decided to end operation of the entire storage field.

**Q. What type of engineering analysis and alternative analysis was performed to develop the Riverside retirement plan?**

A. The engineering and gas supply team performed several models that included full field retirement, plugging and abandoning portions of the field, and optimizing the field with new horizontal wells. The evaluation also included determining gas withdrawal from the gas storage field. During the original analysis low gas price projections, along with the equipment necessary and timing of withdrawal, Consumers Energy determined that it would not be economical for the Company to spend capital to withdraw gas from the Riverside field. The Company modeled and evaluated several alternatives until a solution was determined. The selected solution must mitigate the current storage and transmission risk associated with the field, improve resiliency and reliability to customers connected to McBain, Forward, and Falmouth City Gates (customers that are currently being supplied through the storage field), continue to provide affordable gas in the Riverside area, and reduce methane emissions with the plugging of the storage wells.

In Case No. U-21308, the Company's gas rate case filed in 2022, MPSC Staff ("Staff") submitted testimony acknowledging the unfavorable economics of withdrawing the recoverable gas from the field but recommended that the Company continue to evaluate

the potential sale of Riverside to a third party, who might be in a different economic position to produce the 8.6 Bcf of recoverable gas in the reservoir. The Company agreed to continue reviewing the sale of Riverside as an alternative to retiring and decommissioning the plant.

After gas prices increased in 2022, the Company revisited options for the withdrawal of gas from the field, including the option of selling the field to a third party. In late 2023, the Company identified a buyer and the parties have reached a purchase agreement. A closing date is tentatively planned for late 2025 to allow for the project work to remove customers from being fed by the storage field to be completed.

**Q. What is the estimated timeline and projected cost for the Riverside projects and sale through the year 2026?**

A. A breakdown of the projected spending for the Riverside project is included in Exhibit A-12 (TKJ-5), Schedule B-5.7, page 2, line 18, the projected project spending does not include Cost of Removal. Distribution and Transmission asset modifications to disconnect customers from the storage field and re-supply from the system are planned for 2024 and 2025. Final closing on the sale of the field is planned to occur tentatively before the end of 2025. All projects will be closed out by 2026.

**Q. Why is the sale of Riverside beneficial to customers?**

A. The Company's estimated cost to retire and decommission Riverside is more than $24 million. This estimate includes the plugging of the remaining field wells and retirement of the mainline and laterals. These expenses will be avoided when the field is sold.

Although the sale of the plant is expected to result in a loss of approximately $9 million, the sale allows Consumers Energy to avoid the decommissioning costs, which

creates a net benefit to customers. In Case No. U-21656, the Company sought Commission approval to record the expected loss from the Riverside sale as a regulatory asset for recovery in a future rate case. The Commission approved the Company's accounting request in Case No. U-21656 on July 23, 2024. Company witness Heather L. Rayl discusses the treatment of the regulatory asset in this case in her direct testimony.

**Q. Please identify the capital expenditures projected for the Northville Storage Fields (Lyon 29, Lyon 34 and Northville Reef).**

A. Exhibit A-12 (TKJ-5), Schedule B-5.7, page 2, line 10, identifies the total capital expenditures for the Northville Storage Fields. In 2023, the Company incurred costs for its project to install a liquid handling system at the Lyon 29/34 storage fields. In 2024 through 2026, the projected costs include investment to complete the liquid handling system at the Lyon 29/34 storage fields and begin engineering/procurement on the Northville Reef Field liquid handling system. An itemized list of project costs used to create Exhibit A-12 (TKJ-5), Schedule B-5.7 is included in WP-TKJ-6. A breakdown of well rehabilitation work scope is included in Exhibit A-76 (TKJ-6).

**Q. Please describe the Lyon 29/34 project.**

A. The Lyon 29/34 storage gas gathering and metering site has been in operation for more than 22 years. The facility feeds gas to transmission Line 1020 and to the Northville compressor station. The primary focus of the Lyon 29/34 facility is to deliver transmission quality gas to the pipeline system and act as a metering station. On peak days, this site is an important additional source of natural gas supply to the metro Detroit area. During 2018, 2019, and 2020 there were multiple occasions of gas purity issues occurring during the gas withdrawal season. During gas withdrawal, the gas water content exceeded the

regulatory threshold of 7 LB/MMCF, which affected the storage field, and required premature shut-in of withdrawal operations. The Lyon 29/34 facility upgrade project will help improve gas purity, measurement accuracy, and pipeline reliability by reducing corrosive components from the gas stream and improve site performance by installing gas purification equipment. In 2022, the expenditures were for project engineering and design. The 2023 expenditures were for concluding engineering, design and securing long lead time materials. The 2024 and 2025 expenditures are for securing remaining materials and performing construction, start up and project close out for the project. This project will help address the Company's objective of a reliable system, which will reduce unplanned outages during normal site operations.

**Q. Was gas blending considered as an alternative to this project?**

A. Yes. The Company does not consider blending a competent means of ensuring gas quality. Various conditions can affect how and whether gases are mixed in a pipe. Due to the integrated nature of Consumer Energy's gas system, its variable operating conditions, and the fact that the system is not designed to assure mixing of gas from different sources, it would be inaccurate to assume mixing occurs.

**Q. Please identify the capital expenditures that are planned for the Overisel Storage Fields (Overisel and Salem).**

A. Exhibit A-12 (TKJ-5), Schedule B-5.7, page 2, line 11, identifies the total capital expenditures for the Overisel Storage Fields. In 2023, the Company incurred costs for disposal well tank replacements. In 2024 through 2026, projected costs include scrubber brine tank replacement and a Salem scrubber replacement. An itemized list of project costs

used to create Exhibit A-12 (TKJ-5), Schedule B-5.7 is included in WP-TKJ-6. A breakdown of well rehabilitation work scope is included in Exhibit A-76 (TKJ-6).

**Q. Please identify the capital expenditures projected for the Ray Storage Field.**

A. Exhibit A-12 (TKJ-5), Schedule B-5.7, page 2, line 12, identifies the total capital expenditures for the Ray Storage Fields. In 2023 through 2026, the projected costs include valve replacements and a launcher receiver replacement. An itemized list of project costs used to create Exhibit A-12 (TKJ-5), Schedule B-5.7 is included in WP-TKJ-6. A breakdown of well rehabilitation work scope is included in Exhibit A-76 (TKJ-6).

**Q. Please identify the capital expenditures projected for the St. Clair Storage Fields (Hessen, Puttygut, Four Corners, Swan Creek, Ira, and Lenox).**

A. Exhibit A-12 (TKJ-5), Schedule B-5.7, page 2, line 13, identifies the total capital expenditures for the St. Clair Storage Fields. In 2023 through 2026, examples of projected costs include completion of a disposal well facility upgrade and launcher/receiver replacement at Four Corners. An itemized list of project costs used to create Exhibit A-12 (TKJ-5), Schedule B-5.7 is included in WP-TKJ-6. A breakdown of well rehabilitation work scope is included in Exhibit A-76 (TKJ-6).

**Q. Please identify the capital expenditures that are planned for Storage New Wells.**

A. Exhibit A-12 (TKJ-5), Schedule B-5.7, page 2, line 14, identifies the total capital projected expenditures to complete the Company's new storage well drilling plan. In 2023, the Company incurred costs for the completion of drilling the two wells C-995 and C-996 in the Cranberry field, the re-entry of W-994 in the Winterfield field, and engineering and preparation for future well drilling and close out/flow testing after drilling. In 2024 through 2026, the projected capital expenditures include funding for the engineering, site

preparation, and drilling of new wells. The table below outlines the timing and location of the Company's plan for drilling new wells.

**Table 7: Proposed New Well Drilling Plan**

| Drill Year | Location | Field | New Well ID | Projected Cost |
|---|---|---|---|---|
| 2023 | Marion | Winterfield | W-994 (re-entry) | $3,338,861 |
| | Marion | Cranberry | C-995 | $6,300,178 |
| | Marion | Cranberry | C-996 | $5,251,591 |
| 2024 | Overisel | Overisel | O-305 | $9,759,300 |
| | Marion | Cranberry | C-994 | $6,563,713 |
| 2025 | Marion | Winterfield | W-1004 | $10,253,314 |
| | Marion | Winterfield | W-1005 | $7,728,750 |
| | Marion | Winterfield | W-1006 | $7,728,750 |
| | Marion | Cranberry | C-1103 | $10,641,316 |
| 2026 | St. Clair | Puttygut | P-301 | $8,237,405 |
| | St. Clair | Puttygut | P-302 | $6,852,403 |
| | St. Clair | Four Corners | FC-201 (re-entry) | $3,537,775 |
| | Ray | Ray | R-510 | $9,571,623 |
| | Ray | Ray | R-511 | $7,102,411 |

**Q. Please provide a description of the project at W-994 in the Winterfield Storage Field and FC-201 in the Four Corners Storage Field.**

A. The projects are well re-entries focused on re-entering existing horizontal or deviated wells and drilling new horizontal drainhole sections. Re-entering an existing well further helps to improve field and well deliverability, especially for wells that were drilled off structure or too deep on the structure. The re-entry work is also expected to be significantly less expensive than a full new well as the casing, wellhead equipment and pipeline are already installed. There are eight wells in Winterfield, and one well in Lyon 34, that are potential future candidates pending the results of the W-994 and FC-201 projects.

**Q. Please identify the capital expenditures that are planned for Well Rehabilitation.**

A. Exhibit A-12 (TKJ-5), Schedule B-5.7, page 2, line 15, identifies the total capital projected expenditures for the Storage Well Rehabilitation Capital Program plus the wellhead protection and annular monitoring programs. Exhibit A-76 (TKJ-6), provides detail specific to the Storage Well Rehabilitation Capital Program, a multi-year program that is in response to the federal minimum safety standards that are described previously in my testimony.

Storage Well Rehabilitation Capital Project spending for 2024 through the end of the program was determined using estimates created based on work scopes developed by Storage Engineering. The work scopes are broken down into activities and costs and are developed using the projected duration of the activity using a vendor rate or on a cost-per-well basis, again based on a vendor quote. A description of the different work scopes and associated costs is shown on the Scope Averages tab of Exhibit A-76 (TKJ-6). The scope specific estimates were added together with the wells of similar scope types and averaged. This average was used to build the annual project expenses based on the number of each well scope performed each year. These costs are displayed on the Annual Estimate tabs of Exhibit A-76 (TKJ-6).

**Q. Please provide more detail on the Well Rehabilitation Program.**

A. The primary goal of the Well Rehabilitation Program is to identify and reduce well risk by ensuring the integrity of the wells across the Company's gas storage system, preventing a large-scale methane emission event like Aliso Canyon. The secondary goal is to enhance well deliverability while working on the well. This program will initially provide a baseline of well integrity conditions, which will be incorporated into the ongoing development of the Storage Integrity Management Plan ("SIMP"). Development of the

SIMP is ongoing and the associated Risk Assessment Model is being used to identify well prioritization for the program. The completion of the logging portion will help complete a portion of the baseline assessment required from the PHSMA final rule.

This program will use mechanical methods, solvents, and other chemicals to remove obstructions, restoring the original flow properties of the wells. This thorough Well Rehabilitation Program will remove the debris and slow the rate of corrosion potential in the wells, thus increasing the useful life of the facilities.

Depending on the condition of the well, additional replacement of well components may be necessary. Components include, but are not limited to, piping, valves, or packers. To verify success of the Well Rehabilitation Program, flow statistics are taken both before and after the rehabilitation on select wells. Absolute Open Flow ("AOF") values are measured and compared to historical AOFs taken on the wells when originally put into service. Wells will be "logged" or inspected before treatment to assess the condition of the well casing and the success of the restoration. The program will bring the Company up to a seven-year reassessment cycle, into compliance with the API RP 1171, as part of the Storage system objectives as outlined in the NGDP.

Completing the rehabilitation and well logging work simultaneously is prudent, efficient, and directly benefits customers and public safety. If done separately, services such as well service rigs, well hardware, and other ancillary services would be duplicated, which is not cost effective for the customer. This program is designed to restore, and in most cases, increase well deliverability while baselining well integrity to an industry average of approximately 10 years. Once baseline well integrity information is determined, a risk-based, site specific approach to future well integrity well logging will be

implemented as detailed in the API RP 1171: Functional Integrity of Natural Gas Storage in Depleted Hydrocarbon Reservoirs and Aquifer Reservoirs. At the completion of the well rehabilitation capital project, well logging O&M will be required to maintain the approximately seven-year cycle. The Company is 75% complete in its baseline risk assessment as of January 2024 with 747 wells completed. The Company plans to complete the baseline assessment in 2026.

**Q. Why is the Well Rehabilitation Program a capital program?**

A. Federal Energy Regulatory Commission ("FERC") Docket Nos. AC09-27-000 and AI05-1-000 illustrate FERC's allowance of testing costs incurred to extend the useful life of the system in the context of a one-time rehabilitation program to be capitalized. Under the requirement of FERC's Uniform System of Accounts, costs incurred to inspect, test, and report on the condition of an existing plant to determine the need for repairs or replacements, and testing the adequacy of repairs made, are recognized as maintenance expense. However, FERC has permitted natural gas and electric companies to capitalize assessment costs when the work was done in connection with major rehabilitation projects involving significant replacements and modifications of facilities.

FERC has established the following requirements that a project must meet to be able to capitalize assessment type costs. The project must: (i) be completed in connection with a one-time program that involves significant replacements and modifications of facilities; (ii) extend the overall system's useful life and serviceability; and (iii) have in place internal controls to distinguish between costs incurred related to ongoing assessment activities and those that are part of the rehabilitation project. The Well Rehabilitation Program meets these requirements.

**Q. Please provide more detail on the annular monitoring program.**

A. The annular pressure monitoring program allows for the well casing pressures to be measured, recorded and monitored as per the requirement in API RP 1171. The Company installed monitoring on 43 wells in 2023, 44 wells in 2024 and is projected to install 27 wells in 2025. All wells requiring annular pressure piping will be installed by the end of 2025. Annular pressure monitoring program average cost per well is approximately $15,000. The cost can reach $25,000-30,000 per well if a well plug is needed during the modification. Factors that impact this cost include but are not limited to soil type/condition, installation depth, welding requirements and pipe thickness/material.

**Q. Please identify the capital expenditures that are planned for Storage Pipeline Replacement.**

A. Exhibit A-12 (TKJ-5), Schedule B-5.7, page 2, line 16, identifies the total 2023 through 2026 capital projected expenditures for storage pipeline replacements. The projected pipeline replacement schedule is shown in Table 8, it includes the total projected cost of each project including both pipeline replacement and retirements. Retirement projects are provided for information only, they are entirely Cost of Removal/Retirement ("COR") expense and are not part of the request in this proceeding.

**Q. Please provide more detail on the Storage Pipeline Replacement Program.**

A. The Storage Pipeline Replacement Program is a program that performs replacement and retirement of storage pipelines to reduce the probability of major failure. All storage pipelines replacements and retirements will be tracked under the Transmission Integrity Management Program ("TIMP"), following 49 CFR 192 Subpart O, for risks and consequences of failures. Projects have been prioritized based on factors such as risk,

future new well drilling, and planned well plugging. Replacement and retirement of these storage pipelines contribute to the safety of Company employees and the public, deliverability, resilience, and integrity of the Company's system.

**Table 8: Projected Pipeline Replacement Schedule**

| Year | Location | Project Name | Project Type* | Projected Cost | Length (ft) | Act 9 Required | Anticipated File Date |
|---|---|---|---|---|---|---|---|
| 2023 | Marion | Cranberry Lateral 67E-Launcher/Receiver | Replacement | $815,072 | 53 | No | N/A |
| 2023 | St. Clair | Puttygut Mainline | Replacement | $3,649,000 | 1,426 | No | N/A |
| 2024 | Overisel | Overisel Lateral 2 | Replacement | $8,899,720 | 5,095 | No | N/A |
| 2024 | Marion | Cranberry Lateral 61W | Replacement | $4,620,000 | 1,785 | No | N/A |
| 2025 | Overisel | Overisel Lateral 3 | Replacement | $8,281,000 | 5,227 | No | N/A |
| 2025 | Marion | Winterfield Lateral 52SB | Replacement | $4,446,000 | 1,056 | No | N/A |
| 2025 | St. Clair | Hessen Full field | Replacement | $14,708,988 | 33,898 | Yes | November 2024 |
| 2026 | Overisel | Salem ML 2 | Replacement | $3,752,000 | 4,013 | No | N/A |
| 2026 | Overisel | Salem ML 3 | Replacement | $2,942,000 | 2,800 | No | N/A |
| 2026 | Overisel | Overisel ML -16" | Replacement | $12,675,000 | 13,707 | No | N/A |
| | | | | | | | |
| 2023 | Marion | Cranberry Lateral 62W | Retirement | $1,645,798 | 9,768 | No | N/A |
| 2024 | Overisel | Overisel ML - 10", ML – 12", Lateral 9, 8, 7E/W | Retirement | $5,594,252 | 42,451 | No | N/A |
| 2024 | Marion | Cranberry Lateral 63W | Retirement | $420,000 | 1,486 | No | N/A |
| 2025 | Overisel | Salem North Lobe Retirement | Retirement | $4,142,000 | 16,685 | No | N/A |
| 2025 | Marion | Winterfield Lateral 56N | Retirement | $1,384,000 | 5,069 | No | N/A |
| 2025 | Marion | Winterfield ML 22" | Retirement | $1,366,000 | 6,706 | No | N/A |
| 2026 | Marion | Cranberry Lateral 64W | Retirement | $1,170,000 | 4,832 | No | N/A |
| 2026 | Marion | Cranberry Lateral 66E | Retirement | $4,780,000 | 50,910 | No | N/A |
| 2026 | Marion | Cranberry Laterals 67N/S | Retirement | $1,053,000 | 5,046 | No | N/A |

***** Retirement projects are provided for information only; they are entirely COR expense and are not part of the request in this proceeding.

In previous years, the Company's Enhanced Infrastructure Replacement Program ("EIRP") has provided funding for the storage field lateral and mainline replacements, specifically for known higher-risk pipe within the storage fields. This includes pre-1970 Low Frequency Electric Resistance Welded ("LFERW") pipe. This pipe has been deemed higher relative risk pipe industry wide.

Starting in 2018, the Company ended the Transmission EIRP program and began this program to address the storage pipelines that do not qualify for EIRP funding. The well lines in the Overisel, Salem, Winterfield, Cranberry, and Riverside fields are original piping from initial field construction (Late 1940s and Early 1950s). Leaks have periodically developed on the well lines – average two to five per year across all of the fields. The condition of the well lines cannot be assessed with Inline Inspection tools since they are not piggable.

**Q. Please identify the capital expenditures that are planned for Well Data Acquisition.**

A. Exhibit A-12 (TKJ-5), Schedule B-5.7, page 2, line 17, identifies the total capital projected expenditures for well data acquisition. In 2023, the Company incurred costs for well data acquisition equipment installation and close out at the Ray Storage Field. In 2024 through 2026, project costs include funding for engineering, procurement, and installation of well data acquisition equipment on 24 wells in the Puttygut storage field and 24 wells in the Hessen storage field.

**Q. Please provide more detail on the Well Data Acquisition.**

A. PHMSA's adoption of API RP 1171 recommends increased monitoring of gas storage wells. In order to monitor flow, temperature, pressure, and other variables in real time, Remote Terminal Units and Supervisory Control and Data Acquisition (SCADA) systems

need to be installed and equipped with sensing equipment at the well head. Along with complying with federal regulations, the ability to monitor issues on a well-by-well basis in real time during injection and withdrawal will provide valuable data to storage engineers that can be used to optimize the injection cycle and ensure deliverability from the field. The program plans to implement the technology in the peaker and intermediate fields, along with top performing and/or horizontal wells in the baseload fields. The benefits of a well SCADA system that can log the real time flow, temperature, and pressure will be well performance tracking, consistent annular pressure data and will allow the Company to utilize the data for future workover and maintenance activities.

**Q. Please identify the capital expenditures that are planned for Safety Valve Installation.**

A. Exhibit A-12 (TKJ-5), Schedule B-5.7, page 2, line 19, identifies the total capital projected expenditures for safety valve installation. Funding for safety valve installation projects began in 2024 with 4 wells at the Puttygut and Four Corners storage fields. The projected work scope in 2025 installs 22 safety valves at various well sites within the Puttygut, Hessen and Swan Creek fields and 5 safety valves in the Northville fields. Projected work scope in 2026 includes 6 safety valves installed in the Ira storage field.

**Q. Please provide more detail on the Safety Valve Installation.**

A. A SIMP integrity assessment (based on the regulatory requirements of API RP 1171 as referenced in 49 CFR 192.12) of surface equipment identified the need to standardize safety equipment on certain wells within higher deliverability fields. Protecting against a gas excursion from the individual well bore during any potential safety incidents.

**Freedom Upgrade Project**

**Q. Please describe Exhibit A-12 (TKJ-5), Schedule B-5.7, page 2, line 1.**

A. Exhibit A-12 (TKJ-5), Schedule B-5.7, page 2, line 1, identifies the total capital expenditures for the Freedom upgrade project.

**Q. What level of capital spending does the Company propose for the Commission to incorporate into rates in this case for the upgrade project to Freedom?**

A. The Company's request for rate relief in this case reflects capital spending on the upgrade project to Freedom in the amount of $8.4 million for 2023 (Actual); as provided in Exhibit A-12 (TKJ-5), Schedule B-5.7, page 2, column (b), line 1; $0.7 million for 2024 (Projected), as provided in Exhibit A-12 (TKJ-5), Schedule B-5.7, page 2, column (c), line 1; $0.0 million for the nine months ending on October 31, 2025 (Projected), as provided in Exhibit A-12 (TKJ-5), Schedule B-5.7, page 2, column (d), line 1; $0.7 million for the 21 months ending on October 31, 2025 (Projected), as provided in Exhibit A-12 (TKJ-5), Schedule B-5.7, page 2, column (e), line 1; and $0.0 million for the test year ending October 31, 2026 (Projected), as provided in Exhibit A-12 (TKJ-5), Schedule B-5.7, page 2, column (f), line 1.

**Q. Please summarize the capital expenditures included in Exhibit A-12 (TKJ-5), Schedule B-5.7, included in this direct testimony for the Freedom upgrade project.**

A. Exhibit A-12 (TKJ-5), Schedule B-5.7, page 2, line 1, identifies the total capital expenditures for the Freedom upgrade project. The Company has completed the construction and commissioning of the new equipment in the compressor and auxiliary buildings. In 2024, the Company is completing the site restoration and project close out.

**Q. What is the annual investment for the overall Freedom upgrade project?**

A. The annual investment for the Freedom upgrade project for the completed work and the work that is currently planned is shown in the table below. The projected amounts will continue to be evaluated as the project progresses and moves toward completion.

| **Anticipated Spend (Millions)** | |
|---|---|
| 2016 | $16.8 (actual) |
| 2017 | $30.2 (actual) |
| 2018 | $62.3(actual) |
| 2019 | $83.0 (actual) |
| 2020 | $19.7 (actual) |
| 2021 | $13.8 (actual) |
| 2022 | $13.6 (actual) |
| 2023 | $8.4 (actual) |
| 2024 | $0.6 (projected) |
| 2025 | $0.0 (projected) |
| **Total** | $248.4 (projected) |

**Q. What is the state of Freedom Upgrade Project now?**

A. Freedom has all five new compressor engines (18,750 BHP) permanently installed and commissioned in the new compressor building. Retirement and demolition of existing compressors and buildings has been completed. Site Restoration and Project close out is projected to be completed by the end of 2024.

**Q. Are the Company's capital expenditures in GCS reasonable?**

A. Yes. The capital expenditures in GCS will improve system reliability, deliverability, integrity, safety, and customer service. These capital expenditures will allow the Company to take advantage of market conditions and procure adequate supplies of natural gas to meet

the needs of our customers. Furthermore, many of these capital expenditures are related to compliance with environmental, federal, and/or state regulations, and thus not discretionary.

**(v) IT PROJECTS**

**Q. Is the Company planning technology projects that support the engineering, asset planning, design, construction, and maintenance of a safe, reliable, and affordable distribution, transmission, compression and storage systems for its customers?**

A. Yes. Company witness Stacy H. Baker includes in her direct testimony and exhibits, technology projects that are critically important to supporting these gas functions within the Company. The expenditures for these projects are contained within her exhibits. The project which will provide benefits for the area which I am sponsoring is described below:

- The **Compression Air Permit and Compliance Digitalization** project requires $385,213 in capital and $38,105 in O&M in the test year.

  **Description:** This project modernizes and expands the use of software and digitized forms in support of station air permits and code compliance at Gas Compression facilities.

  **Problem Statement:** The current process around air permits and compliance for Gas Compression is cumbersome, largely paper based, and is made up of multiple disconnected systems. This leads to poor visibility, process inefficiency and waste, re-work, regulatory risk, and human error.

  **Objectives:** This project provides value to the Company through: (1) increased productivity by direct data entry in the field; (2) improved quality through increased accuracy of updates completed at the time and place of the work; (3) elimination of the need to enter data into multiple disconnected systems, and (4) improved safety through access to real-time information used at work sites rather than printed procedures and forms.

  **Scope:** The scope of the project includes: (1) Merging the existing air permit and compliance tools into a single solution, (2) purchasing licenses to add Gas Compression users to the company's existing mobile work management software, and (3) configuring changes in SAP and the mobile work management software to replace the paper-dependent process with the ability to access and update maintenance, operations, and safety information for Gas Compression.

The scope of the project includes: (1) purchasing additional software licenses to add Gas Compression users to the company's existing software solution, and (2) configuring changes in SAP and the mobile work management software to replace the paper-dependent forms and process with the ability to access and update maintenance, operations, and safety information at Gas Compression locations digitally.

**Alternatives:** Alternatives considered include: (1) Utilize an SAP work management mobile solution. An SAP work management solution was not selected since it is an unproven solution at the Company and would require additional project and support costs. (2) Continue with the manual paper-based processes and forms. Continuing with the manual paper-based processes and forms was not selected because it would not eliminate the identified process waste, re-work, and human error. (3) Customize the existing electronic Shift Operations Management System (eSOMS) mobile application to add work management functions. A customized mobile application was not chosen because it would require additional project cost and an ongoing support budget for a custom solution that the product was not intended to support. (4) Adopt a cloud based SAAS solution. This option was not selected as it was a high-cost option. (5) Utilize the existing Service Suite solution currently deployed for Gas and Electric Distribution. The Service Suite solution was selected because it is both an industry standard and a proven solution at the Company and provides the required mobility and digital benefits at a lower cost than other options.

**Q. Does this complete your direct testimony?**

A. Yes.

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

| | | |
|---|---|---|
| In the matter of the application of<br>**CONSUMERS ENERGY COMPANY**<br>for authority to increase its rates for the<br>distribution of natural gas and for other relief. | )<br>)<br>)<br>)<br>) | Case No. U-21806 |

# REBUTTAL TESTIMONY

# OF

# TIMOTHY K. JOYCE

# ON BEHALF OF

# CONSUMERS ENERGY COMPANY

May 2025

**Q. Please state your name and business address.**

A. My name is Timothy K. Joyce, and my business address is 17000 Croswell, West Olive, Michigan 49460.

**Q. Are you the same Timothy K. Joyce who previously submitted testimony in this case?**

A. Yes.

**Q. What is the purpose of your rebuttal testimony?**

A. The purpose of my rebuttal testimony is to rebut the adjustments to Lost and Unaccounted For ("LAUF") and Consumers Energy Company ("Consumers Energy" or the "Company") Use ("CU") gas, and Compression Operating and Maintenance ("O&M") expenses; and Gas Compression and Storage Capital expenditures and recommendations proposed by Michigan Public Service Commission ("MPSC" or the "Commission") Staff ("Staff") witnesses Kevin P. Spence, Citizens Utility Board of Michigan ("CUB") witness Ram Veerapaneni and Attorney General Dana Nessel ("AG") witness Sebastian Coppola.

**Q. How is the remainder of your rebuttal testimony organized?**

A. My rebuttal testimony is organized by topical sections as follows:

I. LAUF and Company Use O&M Expenditure Adjustments

II. Compression O&M Expenditure Adjustment

III. New Well Capital Expenditure Adjustment

IV. Lyon 29/34 (Northville Storage) Dehydration Capital Expenditure Adjustment

V. Storage Capital Expenditure Adjustments

VI. Compression Project Capital Engineering Status Expenditure Adjustment

VII. Compression and Storage Capital Expenditure Adjustments

## I. LAUF AND COMPANY USE O&M ADJUSTMENTS

### A. O&M Expenditure Summary

**Q. Please summarize the adjustments proposed by AG witness Coppola for LAUF and CU O&M expenditures.**

A. A comparison of the Company's O&M expenditure projections to those recommended by the AG is provided in the table below:

| Description | Company Amount (000) | AG Recommendation (000) | AG Adjustment (000) |
|---|---|---|---|
| **LAUF** | | | |
| 12 ME 10/31/26 | 12,709 | 7,823 | -4,886 |
| **CU** | | | |
| 12 ME 10/31/26 | 5,502 | 3,702 | -1,800 |
| **TOTAL** | 18,211 | 11,525 | -6,686 |

### B. AG Witness Coppola

**Q. Please summarize AG witness Coppola's recommendation regarding the amount allocated to LAUF.**

A. On pages 178 and 179 of his direct testimony, AG witness Coppola recommends a 221 MMcf reduction in the LAUF volume based on the Company's 2050 net-zero emissions goals, resulting in reduced LAUF expense of $728,000.

**Q. Do you agree with this recommendation?**

A. No, I do not. There is no mention of the Company's Net Zero goals in the LAUF section of my direct testimony, as suggested by AG witness Coppola, because methane reduction and LAUF are not the same, and should not be treated as synonymous. A reduction in methane emissions does not guarantee a reduction in total LAUF, as LAUF also includes theft, customer billing, metering and storage adjustments, described in my direct testimony on pages 22 through 25. There are methane emissions that are not LAUF, like blowdowns

before construction that are accounted for in project expenses and there are LAUF volumes that are not methane emissions, such as theft and metering inaccuracies. To the extent that there are some methane emissions that are part of LAUF, the use of the five-year average gas loss percentage in the approved LAUF calculation methodology, as shown in Exhibit A-74 (TKJ-3), will account for future methane emission reductions as the Company moves toward its 2050 net-zero goals. Therefore, the Commission should reject Mr. Coppola's position.

**Q. On pages 177 and 178 of AG witness Coppola's direct testimony he recommends a reduction of $1.8 million in CU and $4.158 million in LAUF gas due to an error in the calculation WP-TKJ-14 in the Company's original filing, do you agree with the adjustment?**

A. No, I do not. After filing the case, an error was identified in WP-TKJ-14, however it did not have an impact on the LAUF and CU calculation. The LAUF and CU calculation uses the forecasted volumes for the projected test year based on a five-year average of Public Act 9 of 1929 ("Act 9") transportation customers only, i.e. a small group of transportation customers who do not take service on a tariff rate, but instead take service pursuant to an Act 9 contract. This information is provided from WP-TKJ-15 as shown on line 20 of Exhibit A-75 (TKJ-4). AG witness Coppola incorrectly concluded that the Gas in Kind ("GIK") volumes from WP-TKJ-14 flow into WP-TKJ-15. See page 177, lines 13-14 of Mr. Coppola's testimony. However, that is not entirely accurate. WP-TKJ-14 includes the GIK volumes of the Company's Act 9 customers plus the GIK volumes of transportation customers who are on a tariff rate; whereas, the volumes shown on WP-TKJ-15 include only Act 9 customers. Nevertheless, Mr. Coppola erroneously replaced the Act 9 value

from WP-TKJ-5 on Exhibit A-75 (TKJ-4) with the five-year historical average he requested of the information included in WP-TKJ-14. Compare Exhibit A-75 (TKJ-4), line 20, column (i) with Exhibit AG-62, line 20, column (i). Contrary to Mr. Coppola's unexplained and unsupported assumption, the error in WP-TKJ-14 did not flow into WP-TKJ-15, so the correction to WP-TKJ-14 had no relationship to the Act 9 GIK value used in Exhibit A-75 (TKJ-4), and Mr. Coppola should not have substituted information from WP-TKJ-14 into that exhibit instead of the correct information from WP-TKJ-15. Due to this incorrect application of the LAUF and CU calculation, the Commission should reject Mr. Coppola's recommended disallowance.

## II. COMPRESSION O&M EXPENDITURE ADJUSTMENT

### A. O&M Expenditure Recommendation Summary

**Q. Please summarize the adjustments proposed for Compression O&M expenditures.**

A. A comparison of the Company's O&M expenditure projections to those recommended by CUB is provided in the table below:

| Description | Company Amount (000) | CUB Recommendation (000) | CUB Adjustment (000) |
|---|---|---|---|
| 2024 Projected | 17,030 | - | 0 |
| 2024 Actual | 17,142 | - | 0 |
| 12 ME 10/31/26 | 17,577 | 18,087 | 510 |

### B. CUB Witness Veerapaneni

**Q. On page 18 of his direct testimony, CUB witness Veerapaneni proposes an adjustment for Compression O&M expenditures. Do you agree with this recommendation?**

A. No, I do not. I provided a description of the necessity for the Compression O&M expenditures in my direct testimony beginning on page 7, line 2, through page 10, line 10. Mr. Veerapaneni simply took the average of the 2023 and 2024 actual amounts and applied

inflation to project a test year amount. CUB witness Veerapaneni did not review the reasonableness of the proposed expenditures during the test year or the benefits they would provide to customers. Even though Mr. Veerapaneni's two-year-average methodology results in an increase in O&M expense included in rates in this instance, the Commission should reject his position.

## III. NEW WELL CAPITAL EXPENDITURE ADJUSTMENT

### A. Capital Expenditure Recommendation Summary

**Q. Please summarize the adjustments proposed for New Well capital expenditures.**

A. A comparison of the Company's capital expenditure projections to those recommended by the AG is provided in the table below:

| Description | Company Amount (000) | AG Recommendation (000) | AG Adjustment (000) |
|---|---|---|---|
| 10 ME 10/31/25 | 28,004 | - | -4,647 |
| 12 ME 10/31/26 | 32,296 | - | -3,916 |

### B. AG Witness Coppola

**Q. On pages 80 through 82 of his direct testimony, AG witness Coppola proposes adjustments to the Company's New Well expenditures. Do you agree with the proposed adjustments?**

A. No, I do not. The method that AG witness Coppola uses to determine the proposed adjustments are overly simplistic and do not accurately account for the cost associated with the new well projects. First, Mr. Coppola recommends using a very simple total cost of wells drilled in 2023 and 2024 divided by the number of wells drilled to determine an average cost per new well plus an inflation factor for forecasting the cost of new wells in this case. But that approach assumes that all new wells have a similar geological formation,

drill depths, pipeline lengths, and site preparation. These assumptions are not correct. The Storage Engineering group uses information about the specific attributes of a planned new well to create projected expenses for each of the new well projects. The Company's method is far more accurate for projecting the new well expense than the one proposed by AG witness Coppola. AG witness Coppola's analysis is overly simplistic and does not represent the true new well expense. Therefore, the Commission should reject his position.

## IV. LYON 29/34 (NORTHVILLE STORAGE) DEHYDRATION PROJECT CAPITAL EXPENDITURE ADJUSTMENT

### A. Capital Expenditure Recommendation Summary

**Q. Please summarize the adjustments proposed for Lyon 29/34 (Northville Storage) Dehydration project capital expenditures.**

A. A comparison of the Company's capital expenditure projections to those recommended by the AG is provided in the table below:

| Description | Company Amount (000) | AG Recommendation (000) | AG Adjustment (000) |
|---|---|---|---|
| 2022 Actual | 1,149 | | -1,149 |
| 2023 Actual | 1,191 | | -1,191 |
| 2024 Actual | 6,122 | | -8,453 |
| 10 ME 10/31/25 | 25,249 | | -25,351 |
| 12 ME 10/31/26 | 3,649 | | -4,672 |

### B. AG Witness Coppola

**Q. Please summarize AG witness Coppola's recommended capital disallowance regarding the Lyon 29/34 (Northville Storage) Dehydration project.**

A. Mr. Coppola raises several concerns with the basis, justification, and business needs that the Company has prudently made concerning the Lyon 29/34 (Northville Storage)

Dehydration project. However, none of Mr. Coppola's concerns are valid. I will address each issue individually below.

**Q. On pages 76 and 77 of his direct testimony, Mr. Coppola argues that the total project expense that was included in discovery response U21806-AG-CE-0506 of $37.4 million is different from what was included in the original case filing. Do you agree with his claim about inconsistent project expense estimates?**

A. No, I do not. Mr. Coppola claims that WP-TJK-6 shows larger capital expenditures from 2024 to 2026 than what the Company has included in this case, suggesting that the Company itself is confused about its planned investments in the Lyon 29/34 (Northville Storage) Dehydration project. However, WP-TJK-6 includes costs for two other projects at the Northville storage location in addition to the dehydration project. Mr. Coppola has confused and conflated multiple projects. In coming up with his $41 million figure for the Lyon 29/34 (Northville Storage) Dehydration project, Mr. Coppola inflates the total project expense estimates by using the expenses from the two other projects being performed at the Northville storage location that are listed in WP-TKJ-6. Again, the other two projects are independent of the Lyon 29/34 (Northville Storage) Dehydration project and should not be included in its total project expense. The Company has not presented any inconsistent information about the planned spending on the project.

**Q. On page 77 of his direct testimony, Mr. Coppola mentions his assessment from previous rate cases that the Company should further evaluate the system for a more cost-effective solution. Do you agree with his assessment?**

A. No, I do not. The Company has reviewed technologies and methods to provide the regulatory required 7 lbs/MMcf (max) moisture content as required by Rule 81(4) of the

Commission's Technical Standards for Gas Service (R 460.2381(4)). The project design is reflective of the best evaluated option, providing the ability to operate in a manner that supports the peaking nature of the Northville Lyon 29 and 34 fields, with short cycle "turn on" and "turn off" times, zero emissions, lower O&M costs, and lower installation costs.

**Q. On page 78 of his direct testimony, Mr. Coppola states that "[b]eginning in 2021, the Company changed the utilization of the Northville storage fields to be a peaking storage facility to be used only during days in winter when customer gas demand reaches near peak demand." Do you agree with this statement?**

A. No, I do not. The Northville Storage fields have always been, and continue to be, operated as peaking fields supporting the gas system during times of peak demand. Peak demand is typically experienced due to seasonal loads and can also be experienced due to additional system constraints such as emergencies that limit the amount of gas delivery to the system. The Ray Fire emergency experienced in January 2019 is one example where peak demand was met with the utilization of the Northville storage fields. In mid-March of 2022, the Northville fields were again dispatched; however, utilization was limited due to high moisture content.

**Q. On page 78 of his direct testimony, Mr. Coppola asserts that based on the historical usage of the Northville Storage fields, it is not wise to build a high cost facility that will sit idle and not be utilized other than on rare occasions. Do you agree with his assertion?**

A. No, I do not. As seen in Attachments 3 and 4 of discovery response U21806-AG-CE-0506 (attached to Mr. Coppola's testimony as Exhibit AG-22, pages 5 and 6), the field has been limited in use and manually controlled to avoid exceeding the 7 lbs/MMcf moisture

entering the Company's pipeline system to the extent possible. In other words, the dehydration project is needed so that the Company can utilize the Northville Storage fields more reliably without the risk of impacting Company assets and downstream customers. The Northville Storage fields are peaking units and by design are intermittent use associated with peak demand; however, their dispatch to the system is limited based on the moisture testing data over the last five years. The Company has done additional testing and monitoring since recognizing the issue with moisture content exceeding the regulatory limit, to verify performance up to the moisture content threshold of 7 lbs/MMcf, which is the basis for this project. This project is needed to reduce the risk of utilizing these peaking fields to their design capacity during peak demand, ensuring the capability to deliver consistent gas quality performance and improving system resiliency. After completing this project, the fields will no longer have to be a "last on, first off" resource and are more likely to be used each winter.

**Q. On pages 78 and 79 of his direct testimony, Mr. Coppola states that gas blending can be an effective strategy for achieving gas quality in limited volumes. Do you agree with his position that gas blending can be utilized?**

A. No, I do not. The Company does not consider blending a competent means of ensuring gas quality. Various conditions can affect how and whether gases are mixed in a pipe. Due to the integrated nature of Consumers Energy's gas system, its variable operating conditions, and the fact that the system is not designed to assure mixing of gas from different sources, it would be inaccurate to assume mixing occurs. While Mr. Coppola comments that DTE Gas Company ("DTE") utilizes blending, he provides no specific information regarding

which pipelines or storage fields DTE utilizes blending at nor any analysis concerning the differences between the Company's system and the system operated by DTE.

**Q. On pages 79 and 80 of his direct testimony, AG witness Coppola proposes adjustments to the Company's Lyon 29/34 (Northville Storage) Dehydration project expenditures. Do you agree with the proposed adjustments?**

A. No, I do not. As I have explained above, the Northville Storage fields are a critical part of the Company's natural gas system providing the ability to meet peak demand. The unique ability and configuration of the Northville Storage fields is such that it requires upgrades to meet the regulatory requirements for gas quality, specifically the threshold for moisture content at 7 lbs/MMcf (max). Utilization of the fields is currently limited due to the moisture content as the fields are shut in when the threshold is met. By installing the dehydration equipment proposed, the Company will have the ability to utilize the field to its peaking capacity, ensure reliable gas measurement, limit corrosive liquid from the pipeline system, provide resiliency to the gas system, and ultimately be able to provide more reliable gas service to its customers. The total removal of the project costs in 2022, 2023, 2024, and the bridge and test year is unwarranted and should be rejected by the Commission.

## V. STORAGE CAPITAL EXPENDITURE ADJUSTMENTS

### A. Capital Expenditure Summary

**Q. Please summarize the adjustments proposed for C-1103, W-1004, W-1005, W-1006 New Well projects, and Hessen Field Pipeline Replacement capital expenditures.**

A. A comparison of the Company's capital expenditure projections to those recommended by Staff and the AG is provided in the table below:

| Description | Company Amount (000) | Staff Recommendation (000) | Staff Adjustment (000) | AG Recommendation (000) | AG Adjustment (000) |
|---|---|---|---|---|---|
| 12 ME 12/31/24 | 3,088 | 62 | -2,946 | | |
| 10 ME 10/31/25 | 38,689 | 0 | -38,689 | | -13,450 |
| 12 ME 10/31/26 | 6,494 | 0 | -6,494 | | -2,003 |

**B. Staff Witness Spence**

**Q. On pages 16 through 18 for new wells C-1103, W-1004, W-1005 and W-1006; and pages 19 through 21 for Hessen Storage Pipeline Replacement project, Staff Witness Spence recommends disallowance of the Company's planned capital spending for those projects because the Company does not have approved Act 9 certificates for the projects yet. Do you agree?**

A. No. The Act 9 certificate of need process is not a cost approval mechanism. The gas rate case includes a forward-looking projection of expenses that are appropriate for inclusion in rates during the test year. While construction on these projects cannot commence until after Act 9 approval, the Company will incur legitimate expenses for these projects even before construction begins including engineering and procurement activities. All three of these projects are well-positioned to receive a final Act 9 order before the final order in this rate case, and no party has challenged any of the Act 9 applications to date. Furthermore, the Company accounted for the time required to navigate the Act 9 process when planning for the expected start date for construction, so there is no reason to expect misalignment between the start of construction and the rate recovery included in the Company's filing. The Company appreciates Staff witness Spence's acknowledgement on

page 22 of his direct testimony that Staff may withdraw its recommended disallowances if the Act 9 certificates are approved before the final order in this case. Given the circumstances and current status of these Act 9 filings, the Company believes the Commission would be warranted in approving the test year investments for these projects in rate even if the Act 9 certificates have not been finalized when this order is released.

### C. AG Witness Coppola

**Q. On pages 82 through 83 of his direct testimony, AG witness Coppola proposes that the Commission disallow proposed capital expenditures for the Hessen pipeline replacement because it does not have an approved Act 9 creating uncertainty in the timing of the project expenditures. Do you agree?**

A. No. For the reasons discussed above in response to Staff witness Spence, the Commission should reject Mr. Coppola's similar disallowance recommendation.

## VI. COMPRESSION CAPITAL EXPENDITURE ADJUSTMENT

### A. Capital Expenditure Recommendation Summary

**Q. Please summarize the adjustments proposed for Compression capital expenditures.**

A. A comparison of the Company's capital expenditure projections to those recommended by the AG is provided in the table below:

| Description | Company Amount (000) | AG Recommendation (000) | AG Adjustment (000) |
|---|---|---|---|
| 10 ME 10/31/25 | 786 | - | -786 |
| 12 ME 10/31/26 | 29,295 | - | -29,295 |

**B. AG Witness Coppola**

**Q. On pages 83 and 84 of his direct testimony, AG witness Coppola criticizes the length of time that some Company projects remain in engineering design. Is there any merit to this criticism?**

A. No. Mr. Coppola's unsupported assumption that the project engineering design durations are "very unusual for the relatively moderate size of the projects being undertaken" is incorrect. The duration of the Company's engineering design phase is appropriate for at least two reasons. First, it reflects and includes an appropriate allotment of time to procure the equipment and materials needed to complete construction of the project. The amount of time needed to procure materials and equipment has increased in recent years, which has extended the engineering design phase for some of the Company's projects. But, that longer duration appropriately reflects the state of the marketplace for procuring those materials and equipment. Second, projects with significant construction durations can have a potential impact on system resilience and reliability and impact the Company's ability to support the gas inventory plans. Therefore, it is not prudent to begin projects with a long construction timeline until the engineering is complete. With the Company's recent focus on optimization of the compression fleet, the Company is focusing on having engineering and procurement activities completed prior to proceeding with construction, which results in longer engineering durations. Again, this is an appropriate practice to minimize potential disruption of the Company's ability to serve its customers. I also disagree with Mr. Coppola's observation that the projects he was referring to are necessarily "moderate" in size. In some instances, the investments reflected in this case include only the early spending for projects that will extend beyond the end of the test year. Contrary to

Mr. Coppola's unwarranted assumption, these are large projects that require a considerable amount of engineering and, therefore, more time to complete the engineering.

**Q. Based on his inaccurate claim regarding the "very unusual" duration of engineering design, AG witness Coppola identified thirteen compression projects that will not begin construction until the end of the test year in this case and recommends that the Commission disallow the projects. Do you agree with his recommendation?**

A. No. Mr. Coppola correctly notes that thirteen compression projects have construction and completion dates after the test year, but the Company will still incur costs for those projects during the engineering design phase, including costs for material and equipment procurements as discussed abobe. Therefore, Mr. Coppola's recommended disallowances are inappropriate. The correct ratemaking treatment for projects that incur legitimate capital costs during the bridge period and test year but will not be in service before the end of the test year is to apply an AFUDC offset – not to disallow them. Mr. Coppola's argument that these project costs should not be included in rate base should be rejected by the Commission and the Company's full projection for the compression projects should be approved.

## VII. COMPRESSION AND STORAGE CAPITAL EXPENDITURE ADJUSTMENTS

### A. Capital Expenditure Recommendation Summary

**Q. Please summarize the adjustments proposed by AG witness Coppola and CUB witness Veerapaneni for Compression and Storage capital expenditures.**

A. A comparison of the Company's capital expenditure projections to those recommended by the AG and CUB are provided in the table below:

| Description | Company Amount (000) | AG Recommendation (000) | AG Adjustment (000) | CUB Recommendation (000) | CUB Adjustment (000) |
|---|---|---|---|---|---|
| 2024 Proj | 175,339 | | 0 | | |
| 2024 Act | 165,776 | | -7,563 | | |
| 12 ME 10/31/26 | 162,039 | | | 145,031 | -17,008 |

**B. AG Witness Coppola**

**Q. On pages 84 and 85 of his direct testimony, AG witness Coppola proposes adjustments to the Company's 2024 Compression and Storage capital expenditures based on the proposed versus actual spending levels. Do you agree with the proposed adjustments?**

A. Yes, the Company accepts the proposed adjustment.

**C. CUB Witness Veerapaneni**

**Q. Beginning on page 14, line 14 of his direct testimony, CUB witness Veerapaneni proposes test year adjustments to the Company's Compression and Storage projects that you are sponsoring. Do you agree with these proposed adjustments?**

A. No, I do not. I provided a description of the necessity for the Compression and Storage expenditures in my direct testimony beginning on page 26, line 10, through page 47, line 25. Mr. Veerapaneni simply took the average of the 2023 and 2024 actual amounts and applied inflation to project a test year amount. CUB witness Veerapaneni did not review the reasonableness of the projects proposed during the test year or the benefits the projects would provide to customers. The Company believes that the methodology used by CUB is unreasonable and should be rejected by the Commission.

**Q. Does this conclude your rebuttal testimony?**

A. Yes.

MR. RUSZKIEWICZ: The Company's next witness is Ashley E. Meschke. And based on the stipulation of the parties, the Company moves to bind in Ms. Meschke's testimony, which consisted of direct testimony of a cover page plus 12 pages of prefiled testimony; also rebuttal testimony in the form of a cover page plus 8 pages of prefiled testimony.

The Company also moves to admit the exhibits, and those are marked as A-95, A-96, A-97, and A-98. Thank you.

JUDGE VARCHETTI: Are there any objections to the admission of the direct or rebuttal testimony of Ms. Meschke or any of the associated exhibits?

Hearing none, then, the testimony is bound into the record, and the exhibits are admitted.

MR. RUSZKIEWICZ: Thank you, Your Honor.

(Direct and Rebuttal Testimony bound in)

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

| | | |
|---|---|---|
| In the matter of the application of<br>**CONSUMERS ENERGY COMPANY**<br>for authority to increase its rates for the<br>distribution of natural gas and for other relief. | )<br>)<br>)<br>)<br>) | Case No. U-21806 |

**DIRECT TESTIMONY**

**OF**

**ASHLEY E. MESCHKE**

**ON BEHALF OF**

**CONSUMERS ENERGY COMPANY**

December 2024

**Q. Please state your name and business address.**

A. My name is Ashley E. Meschke and my business address is One Energy Plaza, Jackson, MI 49201.

**Q. By whom are you employed and what is your present position?**

A. I am employed by Consumers Energy Company ("Consumers Energy" or the "Company") as the Director of Lean Strategy

**Q. Please review your educational and business experience.**

A. I have a bachelor's degree in criminal justice with a specialization in Security Management from Michigan State University and a Master's in Infrastructure Planning and Management from the University of Washington. I have been employed with Consumers Energy since 2012 and I have been accountable for the improvement of performance metrics using lean methodologies in various organizations (gas, electric, and customer organizations) for the last eight years. I have also leveraged my expertise to improve several performance metrics associated with EICP during the last five years.

**Q. What are your responsibilities as Director of Lean Strategy?**

A. In the Director of Lean Strategy role, I am responsible for the development, governance, and administration of the operational metrics incorporated in the Company's Employee Incentive Compensation Plan ("EICP").

**Q. What is the purpose of your direct testimony in this proceeding?**

A. The purpose of my direct testimony is to provide support for Consumers Energy's request for rate recovery for the test year EICP employee compensation costs related to operational goals. Specifically, I will discuss the operational goals included in Consumers Energy's EICP and how they provide customer-related benefits.

**Q. Are you sponsoring any exhibits?**

A. Yes, I am sponsoring the following exhibits:

| | |
|---|---|
| Exhibit A-95 (AEM-1) | 2024 EICP Operational Goals; |
| Exhibit A-96 (AEM-2) | 2024 Customer Benefits: Employee Safety; |
| Exhibit A-97 (AEM-3) | 2024 Customer Benefits: Reliability; and, |
| Exhibit A-98 (AEM-4) | 2024 Customer Benefits: Culture Index – Reduced Employee Turnover. |

**Q. Please explain the process for establishing the Company's EICP goals.**

A. Each year, the Company identifies key operational and financial performance indicators to focus on for the next year. The EICP operational goals are key performance indicators that focus on continuous improvement across work and delivery processes resulting in improved outcomes and customer value. Achievement of these goals ties employee performance to improved utility performance and greater levels of customer benefit.

**Q. What operational goals will make up the 2024 EICP portfolio?**

A. The 2024 EICP operational goal portfolio is balanced to produce safe, reliable, and affordable service while ensuring that the Company is strategically positioned for its customers in the future. Successfully achieving goals in Employee Safety, Culture, Customer Experience, Electric Reliability, and Methane Emission Reduction will produce safe, reliable, and affordable service, and it will help to position the Company to be strong and sustainable in the future. Additional information regarding the 2024 portfolio of EICP goals is provided in Exhibit A-95 (AEM-1).

**Q. Please explain the Employee Safety goal.**

A. Employee Safety is measured through two metrics. First, reduction of Recordable Incident Rate (per the Occupational Safety and Health Administration ("OSHA") standard) is a

guide to the number of injuries that may occur based upon the number of hours worked. Second, reduction of high-risk injuries ensures coworkers take proactive actions to reduce Company employees' exposure to high-risk injuries as part of Consumers Energy's Safety Culture improvement process. High-risk injuries (OSHA recordable and non-recordable) are defined in the Edison Electric Institute ("EEI") Safety Classification Learning Model as "High-Energy Serious Injury or Fatality (HSIF): Incident with a release of high energy in the absence of a direct control where a serious injury is sustained."

**Q. Why is the Employee Safety goal included in the EICP?**

A. Employee Safety is foundational to the success of the Company. Creating and maintaining a culture of safety allows the Company to serve customers safely and affordably while caring for co-workers. Economic benefits for customers are discussed later in my testimony.

**Q. Please explain the Culture Index goal.**

A. The Company uses an all-employee survey to determine the Culture Index which is made up of the indexes of (i) Engagement; (ii) Empowerment; and (iii) Diversity, Equity, and Inclusion. The Company's Engagement; Empowerment; and Diversity, Equity, and Inclusion indexes are how we measure culture values in action. The indexes focus on areas such as ensuring the Company has simple processes, fixes problems, and keeps the workforce engaged by measuring the combination of emotional commitment (how proud coworkers are to work here) and rational commitment (whether they plan to stay). The indexes also measure how well the Company embeds diversity, equity, and inclusion into everything it does through questions that ask whether coworkers feel like they belong at Consumers Energy and other questions described in Exhibit A-95 (AEM-1). Each of the

three indexes is derived by averaging the favorability score from the responses regarding five questions per index, of the Company's employee engagement surveys. Korn Ferry administers the survey using Qualtrics as the survey platform.

**Q. Why is the Culture Index goal included in the EICP?**

A. The Culture Index goal focuses on improving the employee experience and engagement in their work. Companies that experience high employee engagement have 10% higher customer loyalty and engagement and 18% more productivity than companies with low engagement as detailed in Gallup's most recent meta-analysis on engagement, covering more than 112,000 teams, in 276 organizations, across 54 industries, and in 96 countries.[1] Improving Culture will reduce employee turnover and improve the Company's ability to affordably serve customers. Benchmark data shows that peer utilities experience turnover at a rate of 7.3%, while the four-year historical average for the Company has been 3.3%. Unsurprisingly, retention and engagement are correlated. Companies with first-quartile employee engagement experience 43% less turnover and 18% lower absenteeism. While the Company's retention rate is higher than peers, its turnover rate among co-workers who have been with the Company for four years or less does trend higher than the average rate at a four-year historical average of 4.2%. The cost of turnover is high, with estimates that the turnover of an employee can cost a company 1.5-2.0 times the existing employee's salary as the organization experiences additional recruitment activities and lost productivity. For purposes of quantifying customer benefits, I will utilize the lower end of this range, 1.5 times the existing employee's salary. Of the Company's coworker base, 2,581 have four or less years with the Company. Creating and building upon an employee

[1] https://www.gallup.com/workplace/285674/improve-employee-engagement-workplace.aspx#ite-285704)

experience that fosters improved retention within that work group enables the Company to provide better service to customers and avoid unnecessary costs. Through the Company's Culture Index goal, a focus on improving culture will lead to retention of shorter tenured Company employees. With a continuously improving culture, Consumers Energy is able to achieve and maintain a minimum of a 2% advantage over its peers' total experience within this four years or less tenured population of co-workers. By creating and maintaining this competitive advantage over peer utilities, the Company avoids costs of at least $7.4 million annually.

**Q. Please explain the Customer Experience Index goal.**

A. Customer Experience Index is a survey administered by Forrester[2] and is a measure of customer service based on three questions: Did we meet your needs? Was it easy to do business with us? Was the experience enjoyable? The metric is calculated by asking those three questions of customers on a scale of 1 to 5 with 4s and 5s being positive responses, 1s and 2s being negative responses, and 3s being a neutral response. To calculate the score, the number of negative responses is subtracted by the number of positive responses, which is then divided by the total number of customers responding. The results of the three questions are averaged together to calculate the Customer Experience Index score.

**Q. Why is the Customer Experience Index goal included in EICP?**

A. The Customer Experience Index goal focuses on ensuring that when customers contact Consumers Energy, customer needs are met, the interaction is easy for the customer, and the experience is enjoyable for the customer. This results in enhanced productivity (e.g. reducing the number and duration of customer calls, which benefits the Company and

[2] https://go.forrester.com/analytics/

the customer) and customer value (e.g. quick, easy, and enjoyable solutions for customer experiences).

**Q. Please explain the Electric Reliability goal.**

A. The Company uses the industry standard for Customer Outage Minutes, or System Average Interruption Duration Index ("SAIDI"), as a measure of electric distribution reliability. Electric Reliability/SAIDI is a utility-industry benchmark; SAIDI measures the total time an average customer experiences a non-momentary power interruption in a one-year period.

**Q. Why is the Electric Reliability goal included in EICP?**

A. The Company is committed to providing Customers with safe, reliable, and affordable service. Improving electric reliability provides an economic benefit to customers and strategically positions the Company to be successful in the future. Economic benefits for customers are discussed later in my testimony.

**Q. Please explain the Methane Emissions Reduction goal.**

A. This goal tracks the reduction in fugitive methane emissions associated with the Company's natural gas distribution system. Reductions are obtained as a result of the following activities: (1) retiring and replacing miles of natural gas distribution mains, (2) retiring and replacing natural gas distribution services (both vintage and non-vintage materials), (3) natural gas distribution system leak replacements, (4) well plug and abandonment activities, and (5) reducing compression venting. Work groups performing these activities include Natural Gas Construction, Natural Gas Distribution, and Contractors. These activities are further outlined in the Company's Natural Gas Delivery Plan, Exhibit A-42 (NPD-1).

**Q. Why is the Methane Emission Reduction goal included in EICP?**

A. The Company is committed to providing Customers with safe, reliable, and affordable service. In 2020, Michigan's Governor signed an executive order creating the Michigan Healthy Climate plan, which outlines goals for Michigan to achieve economy-wide net-zero greenhouse gas emissions and to be carbon neutral by 2050. The executive order aims for a 28% reduction below 2005 levels of greenhouse gas emissions by 2025. This goal supports the federal government's goal of net-zero emissions economy-wide by 2050 as well as the Paris Agreement. In addition to supporting these goals through the Company's Clean Energy Plan, it is important to address greenhouse gas emissions from the natural gas portion of the business as well. The largest constituent of natural gas is methane, which is a greenhouse gas 25 times more potent than carbon dioxide, and reducing those emissions is a key component to combating climate change. As a result, the Company has set a goal of net-zero methane emissions from its natural gas delivery system by 2030. The Company plans to reduce methane emission from its system by about 80% by accelerating the replacement of aging pipe, rehabilitating or retiring outdated infrastructure, and adopting new technologies and practices. The remaining emissions will be offset by purchases and/or producing renewable natural gas. By achieving this goal, the Company will reduce its methane emissions by more than 10,000 metric tons — that's the equivalent of removing about 55,000 vehicles from the road for a year or preserving more than 300,000 acres of forest. Reducing those emissions will support limiting global emission increases which have been attributed to increased storm activity globally as well as here in Michigan. Consumers Energy is committed to caring for people, protecting the planet and empowering Michigan's prosperity. The achievement of this goal ensures that

the Company will be able to serve its customers safely, reliably, and affordably for many years.

**Q. Please explain the goal target setting process.**

A. Alignment of goal targets with strategic plans is developed by subject matter experts and recommendations for annual targets are provided to the Company leadership team. The leadership team evaluates the recommendations and ensures that there is a focus on continuous improvement and customer value. Targets are established to set clear expectations of continuous performance improvements that are challenging but achievable goals. Operational targets are approved annually by the Board of Directors.

**Q. Has the Company quantified customer benefits that are tied to its EICP?**

A. Yes. Although specific quantification of the benefits is not easy to perform for every metric included in the program, the Company has evaluated direct quantitative benefits of three key metrics of the program: Employee Safety, Electric Reliability, and Culture. And the Company has assessed indirect and/or qualitative benefits associated with the other metrics.

**Q. Is there a direct tie between the design of the EICP operational goals and desirable benefits for customers?**

A. Yes. There is a direct tie between the design of the EICP operational goals and desirable benefits for customers. The operational goals focus on safety, reliability, and customer value, which are all desirable benefits for customers.

**Q. Do you believe that benefits to customers from the EICP goals will, at a minimum, be commensurate with the programs' costs?**

A. Yes. Company witness Amy M. Conrad and I present evidence in support of including EICP costs at the 100% payout level proving that including these costs will not result in excessive rates and that the costs of the EICP will, at a minimum, be commensurate with the programs' costs. Company witness Conrad discusses various benefits to customers from the design of the Company's EICP. In addition, there are both quantitative and qualitative benefits to the successful achievement of these goals. The design of the EICP clearly leads to lower costs and improved service which benefit customers.

**Q. How have you evaluated the EICP goals' direct quantitative benefits?**

A. The direct quantitative benefits associated with Employee Safety, Electric Reliability, and Culture Index have been calculated. For each of these metrics the Company uses a four-year historical average baseline. The first of those metrics is Employee Safety. The Employee Safety goal for 2024, when met, will reduce incidents by 29% from the four-year historical average. The resulting reduction in lost workdays and medical expenses approximates $968,000 of annual direct savings. Expected indirect savings, calculated using OSHA's recommended multiplier, total $656,000. Together, the projected annual direct and indirect savings that accrue to the benefit of the customer total $1.6 million. Exhibit A-96 (AEM-2) provides the calculation of these savings. The second metric that can be readily translated to quantifiable cost avoidance for customers is in electric distribution reliability. Using cost per outage minute estimates from Berkeley Labs,[3] the 5.0-minute average annual reduction in outage minutes from the 2020-2023 historical

[3] https://www.osti.gov/servlets/purl/963320

baseline to the 2024 Electric Reliability goal of 170 minutes results in annual economic benefits to customers in excess of $15.4 million. Exhibit A-97 (AEM-3). Third, there are benefits related to the Culture Index created by reducing employee turnover for Company employees with <1-4 years of tenure by 2% as compared with industry peers. The average annual salary of an employee with tenure of <1-4 years experience is $95,346. And, as discussed above, lower turnover avoids costs equal to at least 1.5 times the employees' annual salaries. This means that by reducing turnover in this employee group by 2%, when compared to utility peers, the Company will avoid costs of $7.4 million. Exhibit A-98 (AEM-4) shows the calculation in further detail.

**Q. How have you evaluated the EICP goals' other qualitative benefits?**

A. Methane Emission Reduction is essential to achieving the Company's goal of net-zero methane emissions from its natural gas delivery system by 2030, which supports the Michigan Governor's goal for Michigan to achieve economy-wide net-zero greenhouse gas emissions and to be carbon neutral by 2050. The direct economic benefits for customers are difficult to calculate, but the qualitative benefits are beyond dispute. Improved Customer Experience is another benefit of achieving EICP goals that is difficult to quantify but nonetheless quite real. The benefits of pursuing improvement in Customer Experience have been discussed above.

**Q. Why have you included both electric and natural gas benefits in your quantification?**

A. Consumers Energy's utility operations are combined in one organization. Establishing operational goals in the critical areas of safety, reliability, customer value, and employee culture helps keep employees focused on the importance of continuous improvements in these priority areas for both the electric and natural gas operations. The quantified benefits

of Employee Safety and Employee Culture show that benefits to natural gas customers clearly exceed the employee incentive compensation amounts that Consumers Energy has requested to be included in rates in this case. The EICP metrics are based on annual targets that support the achievement of Consumers Energy's continuous improvement goals that significantly benefit the customers.

**Q. What portion of the direct benefits that you have quantified above do you conclude benefit natural gas customers?**

A. A portion of the quantified benefits in the area of Employee Safety and avoided costs associated with Culture Index benefit natural gas customers. Utilizing an allocation of 40% for natural gas customers, this equates to annual savings for natural gas customers of $640,000 for Employee Safety, plus the cost avoidance benefit of improved employee retention of $2,960,000 totals $3,600,000, far exceeding the total costs of the EICP allocated to natural gas customers.

**Q. Why did you use a 40% allocation to evaluate benefits to natural gas customers?**

A. The 40% allocation is based on the total number of natural gas employees as a percentage of total number of Consumers Energy employees. Using the percentage of total employees is a reasonable allocation methodology to allocate the Employee Safety and Culture Index benefits identified above.

**Q. Should the Company be pursuing these benefits independent of the EICP?**

A. Yes. The EICP takes this into consideration. As discussed by Ms. Conrad in her direct testimony, incentive mechanisms help communicate priorities, engage employees in business success, reward valued skills and behaviors, and create business understanding for employees. The EICP is structured in a way that focuses employees on enhancing

customer value through continuous improvement outcomes. Making it clear to employees that a portion of their market-based compensation is at risk and depends upon their collective ability to meet these targets emphasizes the importance of improving customer value and encourages coworkers to deliver their best performance.

**Q. Do you believe that the EICP is the reason that the above benefits have been realized?**

A. Yes. I believe that the design of the EICP is intended to, and does, make it significantly more likely that these customer benefits will be achieved through the improvement in the areas of focus identified by the EICP goals. By placing a portion of employees' market-based compensation at-risk, they are incentivized to deliver on the EICP goals related to safety, reliability, and employee culture.

**Q. Do you believe that any of the metrics included in the EICP are duplicative?**

A. No. The metrics have been selected to create a designed, balanced focus on safety, reliability, and employee culture that results in broad customer benefits.

**Q. Does this conclude your direct testimony?**

A. Yes.

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

| | | |
|---|---|---|
| In the matter of the application of<br>**CONSUMERS ENERGY COMPANY**<br>for authority to increase its rates for the<br>distribution of natural gas and for other relief. | )<br>)<br>)<br>)<br>) | Case No. U-21806 |

# REBUTTAL TESTIMONY

# OF

# ASHLEY E. MESCHKE

# ON BEHALF OF

# CONSUMERS ENERGY COMPANY

May 2025

**Q. Please state your name and business address.**

A. My name is Ashley E. Meschke, and my business address is One Energy Plaza, Jackson, Michigan 49201.

**Q. Are you the same Ashley E. Meschke who previously submitted testimony in this case?**

A. Yes.

**Q. What is the purpose of your rebuttal testimony?**

A. The purpose of my rebuttal testimony is to rebut the direct testimony presented by Attorney General witness Sebastian Coppola regarding Consumers Energy Company's ("Consumers Energy" or the "Company") Employee Incentive Compensation Plan ("EICP"). I will specifically respond to Mr. Coppola's comments about the operating performance measures.

**Q. Are you sponsoring any exhibits?**

A. No.

**Q. Please provide an overview of your rebuttal testimony.**

A. Mr. Coppola argues that $526,000 of EICP expenses included in the test year should be disallowed. On page 190, lines 8 through 11 of Mr. Coppola's direct testimony, he states that cost savings calculated are inconsistent with recent trends in performance, aspirational, and not based on actual performance. This is incorrect and my rebuttal testimony provides further information to substantiate that customer benefits from the EICP program exceed the cost to customers. Mr. Coppola's recommendation to disallow EICP costs should be rejected.

**Q. Are you seeking full recovery of the customer benefits of $3,600,000 as outlined in your direct testimony?**

A. No. It is important to clarify that the intent of my testimony is not to recover the full projected cost savings for the test year. Instead, it is intended to provide a reasonable expectation of customer benefits in the test year as the Company achieves operational goals associated with the EICP. My testimony and supplemental exhibits outline $3,600,000 in projected savings – which exceeds the Company's request for recovery of $1,546,000 and is considered reasonable and prudent for the Company's customers.

**Q. On page 189, lines 6 through 9, Mr. Coppola indicates that there has been a negative performance trend in safety incidents. Do you agree with his assessment?**

A. No. Mr. Coppola's analysis of recordable incidents on a short-term basis to assert a negative trend does not accurately reflect the Company's overall safety performance, as detailed later in my testimony. In 2007 and 2008 the Company incurred 558 and 335 incidents respectively, prompting a transformation in its approach to employee safety and health. Since 2012, recordable incidents have consistently been at or below 150 per year, and the Company has exceeded the average performance of peer utilities nine of the last ten years.

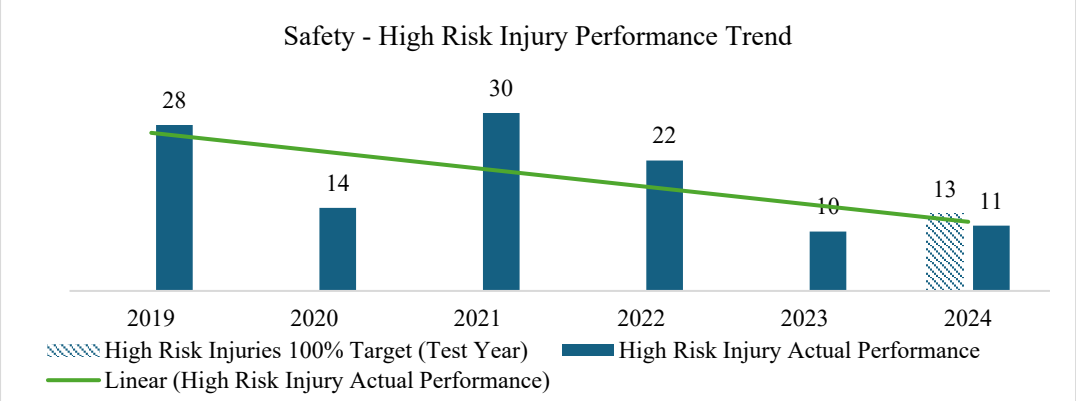
**Q. Please explain why only analyzing recordable incidents is not a holistic representation of the Employee Safety EICP operating performance metric.**

A. As outlined in Exhibit A-39 (AMC-1), the Employee Safety EICP operating performance measure is composed of three components: (1) Recordable Incident Rate, (2) High Risk Injuries, and (3) Fatalities. The Recordable Incident Rate accounts for 30% of the metric and the total number of recordable incidents is only one variable of the equation outlined in Exhibit A-95 (AEM-1). High-Risk Injuries account for 70% of the metric and include

both OSHA recordable and non-recordable incidents that have the potential to result in a severe injury or fatality. In the event there is a fatality, there is a 0% payout for the Employee Safety operational goal in its entirety. Many peer utilities in the industry are shifting their focus toward high risk and severity-based incidents as opposed to recordables, and the Employee Safety operational measure weighting reflects changes in the industry.

**Q. Please explain the trend in High Risk Injuries and fatalities to provide a more holistic representation of the Employee Safety EICP operating performance metric.**

A. As previously stated, the Company began tracking High Risk Injuries in 2019, and the historical performance indicates a strong positive performance – with a notable change starting in 2022 which was the first year the metric was included as part of the Employee Safety metric for the EICP.




Additionally, the Company's last employee fatality was in 2018 and this year marks the longest duration in the Company's 139-year history without an employee fatality.

**Q. Do you believe the Employee Safety metrics have improved because they have been included in the EICP operating performance measures?**

A. Absolutely. As Company witness Amy M. Conrad outlines in her direct testimony on pages 11 through 12, the intent of the EICP operational metrics is to incentivize employees

to participate in increasing productivity and achieving performance metrics that are critical to the Company's utility business and customers. This is one of several examples where including a metric in the Company's EICP has led to positive performance trends. The Employee Safety metric is designed to ensure employee safety and well-being – while preventing productivity losses that can result in delays in completing the work plans that will deliver safe and reliable service to customers and keeping the cost associated with safety incidents low.

**Q. On page 189, lines 8 and 9 of Mr. Coppola's direct testimony, there is an indication that achieving 81 recordable incidents is unrealistic. Do you agree?**

A. No. This is the target that has been established to drive continuous improvement in the Company's safety performance – while striving to achieve high performance compared to peer utilities in benchmark studies. Although it may be aggressive, it is intended to be challenging, yet achievable to keep employees motivated to achieve the targeted levels of performance. EICP targets are established with the intent of achieving a first quartile performance compared to peer utilities.

**Q. On page 189, lines 9 and 10 of Mr. Coppola's direct testimony, Mr. Coppola indicates that the data provided in Exhibit A-96 (AEM-2) does not indicate actual cost savings. Do you agree with his assessment?**

A. The Company never stated that the savings shown in my exhibits represent historical costs savings. My exhibits demonstrate the cost savings that the Company would expect to realize and pass on to customers in future if it achieves the operations goals associated with each exhibit. Furthermore, as I discussed earlier in my rebuttal testimony, the Company is not asking the Commission to approve EICP costs equivalent to the expected savings. My

exhibits show that the expected savings are meaningfully higher than the costs to achieve them and justify the modest amount of EICP expense the Company is requesting in this case.

**Q. On page 189, lines 11 through 14, Mr. Coppola highlights that the costs associated with safety incidents have increased not decreased and that costs have been erratic between 2020 and 2023. Do you agree with this assessment?**

A. No. Mr. Coppola has not provided sufficient analysis to make this claim. The cost outlined in Exhibit A-96 (AEM-2) is broken down by lost time and medical expenses, workers' compensation, and other exposures. To adequately indicate a trend in costs, cost per incident should be analyzed as opposed to total cost. When analyzing these costs between 2020 and 2024, there is a negative trend in costs associated with lost days. In reviewing the cost per incident associated with medical expenses, workers compensation, and other exposures, there has been an increase in actual costs – which is reasonable given national headlines indicating the rise in inflation and healthcare cost since 2020. However, the cost trends are not erratic as Mr. Coppola indicates. These costs are within statistical control limits. Additionally, by including High Risk Injuries into the EICP, the Company is focused on reducing the potential for safety incidents that have the potential to result in a fatality or severe injury – which would more than likely result in higher costs – as opposed to injuries such as insect bites and minor abrasions – which are also included in the cost savings projection.

**Q. On page 189, lines 16 through 20, of his direct testimony, Mr. Coppola criticizes the Company's methodology used to calculate customer savings based on projected savings in 2024 versus actual savings for the System Average Interruption Duration Index ("SAIDI") metric. Do you agree with his opinion?**

A. No. For the test year, the company leveraged the EICP 100% target for SAIDI of 170 customer minutes to estimate projected cost savings to customers. This is a reasonable approach to indicate the savings customers should expect when the Company achieves targeted levels of SAIDI performance. If the Company leveraged actuals from 2020-2024 and calculated the average impact, the results would have been 155 customer minutes in 2024 – resulting in an eight-minute reduction in customer minutes and customer benefits of $25,115,262 as opposed to the results outlined in Exhibit A-97 (AEM-3). This indicates that the Company's approach to calculate projected savings are conservative and understated by three minutes and $9,687,366.

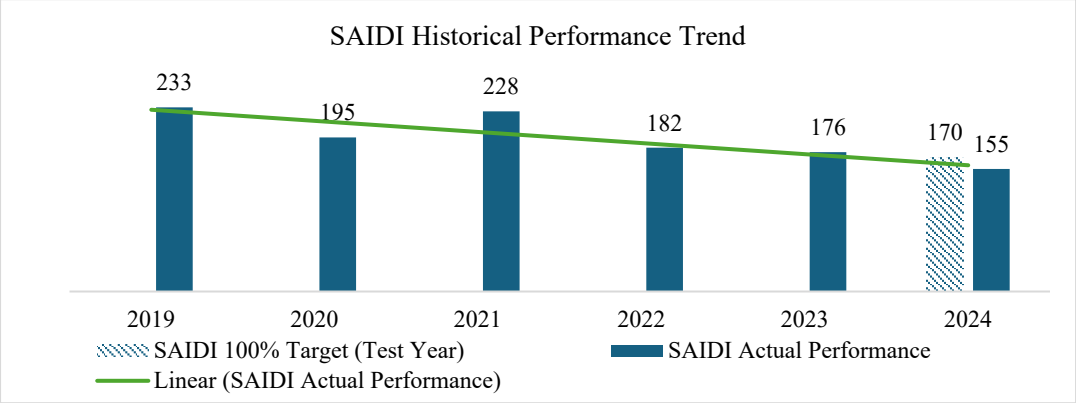
**Q. Why does the Company use a four-year historical average to project savings?**

A. Leveraging historical averages to set targets and project customer benefits is the best practice in data analytics because it provides a more stable and reliable basis for decision-making. This approach avoids the inconsistencies and anomalies that can arise from year-over-year fluctuations, ensuring that targets are based on consistent long-term trends.

**Q. Do you believe the EICP program has positively contributed to SAIDI performance?**

A. Yes. This is another example that illustrates a positive performance trend can be observed when a metric is included in the Company's EICP – as outlined earlier in my testimony. If you analyze the longer-term trend in SAIDI performance, you will see a negative trend

over the last several years – demonstrating the Company's commitment to continuous improvement to deliver customer value through EICP operating performance measures.




**Q. On page 190, lines 2 through 4, of his direct testimony, Mr. Coppola indicates that there has been a negative performance trend in employee turnover between 2020 and 2023. Do you agree with his statement?**

A. No. The 2020 data point selected by Mr. Coppola to indicate a negative trend represents an extreme outlier in the Company's historical performance trend. It should be noted that, in 2020, voluntary turnover during the COVID-19 global pandemic was generally exceptionally low in many industries due to economic uncertainty and unprecedented actions by governments to curtail normal business activity. As referenced in my direct testimony on page 4, lines 11 through 12, the Company's employee turnover rates are significantly lower than the average across peer utilities and indicate a very strong performance. When achieving performance in the top quartiles, it is natural to see some year-over-year variation without significant performance improvement. Instead, the goal is focused on maintaining the Company's strong performance.

**Q. On page 190, lines 5 through 7, Mr. Coppola indicates that this is a clear mismatch between employee satisfaction measures and cost savings based on peer company turnover rates. Do you agree with his assessment?**

A. No. In Exhibit A-95 (AEM-1), the Company outlines the Culture Index survey questions. The following questions from the survey are leading indicators for employee retention: (1) If I were offered a similar job elsewhere at the same pay, I would stay at the Company; (2) Given your choice, how long would you plan to continue working for the Company?; (3) I would recommend my Company as a good place to work; (4) I feel proud to work for the Company; (5) I feel able to be myself at work; and (6) I feel like I belong at the Company. Consumers Energy's historical trends indicate that there is a strong correlation between its Culture Index and employee turnover. When Culture Index performance is high, the employee turnover is low. Despite fluctuations in year-over-year performance, the Company has consistently exceeded benchmark performance in employee turnover – illustrating that by including the Culture Index in the Company's EICP operational metrics it is achieving a cost savings compared to peer utilities.

**Q. Does this conclude your rebuttal testimony?**

A. Yes.

MR. RUSZKIEWICZ: Company's next witness is Heidi J. Myers. Based on the stipulation of the parties, the Company moves to bind in the testimony of Heidi J. Myers. She had direct testimony which was confidentially filed, consisting of a cover page plus 16 pages of prefiled testimony. Ms. Myers also had rebuttal testimony that was a cover page, plus 17 pages of prefiled testimony.

The Company also moves to admit Ms. Myers' exhibit. It was confidentially filed, and also redacted filed, as Exhibit A-79. Thank you.

JUDGE VARCHETTI: Are there any objections to the admission of the testimony, direct and rebuttal, of Ms. Myers, or the associated exhibits?

Hearing none, the testimony is bound into the record, and the exhibits are admitted.

MR. RUSZKIEWICZ: Thank you, Your Honor.

(Direct Testimony bound into the Confidential Record)

(Rebuttal Testimony bound in)

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

| | | |
|---|---|---|
| In the matter of the application of **CONSUMERS ENERGY COMPANY** for authority to increase its rates for the distribution of natural gas and for other relief. | ) ) ) ) ) | Case No. U-21806 |

**REDACTED**

# DIRECT TESTIMONY

**OF**

**HEIDI J. MYERS**

**ON BEHALF OF**

**CONSUMERS ENERGY COMPANY**

December 2024

**Q. Please state your name and business address.**

A. My name is Heidi J. Myers, and my business address is One Energy Plaza, Jackson, Michigan 49201.

**Q. By whom are you employed and in what capacity?**

A. I am employed by Consumers Energy Company ("Consumers Energy" or the "Company") as the Executive Director of Revenue Requirements and Regulatory Affairs.

**Q. Please describe your educational background.**

A. I received a Bachelor of Arts degree in Accounting in 2003 from Michigan State University. I received a Master of Business Administration degree in 2012 from the University of Michigan – Flint. I am also a Certified Public Accountant licensed in the state of Michigan.

**Q. Please describe your professional experience.**

A. From 2004 to 2008 and from 2012 to 2015, I was employed by the Michigan Public Service Commission ("MPSC" or the "Commission") as an auditor and later as the Manager of the Revenue Requirements Section. From 2008 to 2012 and 2015 to 2017, I was employed by the Lansing Board of Water and Light ("BWL"). During my tenure at the BWL, I held the following positions: Senior Rate Analyst, Executive Financial Assistant, Field Services Supervisor, Manager of Human Resources, and Supervisor of Finance and Planning. I joined Consumers Energy in January of 2017 as a Principal Rate Analyst and was promoted to Director of Revenue Requirements and Analysis in March 2018 and was promoted to Executive Director of Revenue Requirements and Regulatory Affairs in June 2020.

**Q. What are your responsibilities as the Executive Director of Revenue Requirements and Regulatory Affairs at Consumers Energy?**

A. As the Executive Director of Revenue Requirements and Regulatory Affairs, I am responsible for regulatory stakeholder collaboration and project management for the development of regulatory filings and communications as well as managing and preparing studies related to the level of the Company's revenue requirements, including the preparation, and monitoring of gas and electric rate case filings before the Commission and other financial analyses. In addition, I oversee the calculation of the Company's Gas Cost Recovery and Power Supply Cost Recovery monthly billing factors. Beginning in July 2023, I also assumed responsibility for cost, pricing, and regulatory policy.

**Q. Have you previously filed testimony with the Commission?**

A. Yes.

**Q. Please state the proceedings you have been involved in.**

A. I sponsored testimony in the following cases:

Case No. U-14347 – Consumers Energy electric rate case;

Case No. U-14547 – Consumers Energy gas rate case;

Case No. U-17087 – Consumers Energy electric rate case;

Case No. U-17473 – Consumers Energy securitization;

Case No. U-18322 – Consumers Energy electric rate case;

Case No. U-20102 – Consumers Energy electric credit A;

Case No. U-20103 – Consumers Energy gas credit A;

Case No. U-20134 – Consumers Energy electric rate case;

Case No. U-20165 – Consumers Energy integrated resource plan;

Case No. U-20286 – Consumers Energy electric credit B;

Case No. U-20287 – Consumers Energy gas credit B;

Case No. U-20309 – Consumers Energy calculation C;

Case No. U-20697 – Consumers Energy electric rate case;

Case No. U-20889 – Consumers Energy securitization;

Case No. U-21389 – Consumers Energy electric rate case;

Case No. U-21490 – Consumers Energy gas rate case; and

Case No. U-21585 - Consumers Energy electric rate case.

**Q. What is the purpose of your direct testimony in this proceeding?**

A. The purpose of my direct testimony is to provide an overview of the Company's gas general rate case filing. I introduce key proposals included in this case and provide a brief introduction to the Company's witnesses and the topics supported in their respective testimony and I discuss the requirements for the Company's next gas rate case (i.e. this case) as set forth in the approved settlement agreement in the Commission's July 23, 2024 Order in Case No. U-21490. Finally, I describe the amounts included for recovery in this case related to the SAP S/4HANA Implementation Project ("SAP Project") and request the deferral of related operating and maintenance ("O&M") expense and an adjustment to the amortization period of the cloud implementation cost for the software as a service ("SaaS") solutions associated with the project.

**Q. Are you sponsoring any exhibits with your direct testimony?**

A. Yes. I am sponsoring the following exhibit:

| | |
|---|---|
| Confidential Exhibit A-79 (HJM-1) | SAP S/4HANA Implementation Project – Revenue Deficiency Impact of O&M Deferral. |

**COMPANY OVERVIEW**

**Q. Please provide a brief description of Consumers Energy and its service territory.**

A. Consumers Energy is a combination electric and gas utility that has powered Michigan's progress for 138 years. The Company provides natural gas service to approximately 1.8 million customers in Michigan's lower peninsula.

**CASE OVERVIEW**

**Q. Please summarize the key drivers of the Company's request in this case.**

A. The Company requests rate relief in the amount of $248 million, which is summarized in Table 1:

**Table 1**

| | *(In Millions)* |
|---|---|
| **Investment** | $ 135 |
| **Cost of Capital** | $ 44 |
| **ASP Gain Previously Used to Offset Revenue Requirement**[1] | $ 27 |
| **Operating Expenses** | $ 42 |
| **Rate Relief** | **$ 248** |

**Q. How does this request impact residential customer bills?**

A. The Company anticipates that the average monthly residential bill for the 12 months ending October 2026 will increase by 12.1% over current rate levels. If the entirety of this request is approved, Consumers Energy expects that the average residential natural gas customer

[1] Pursuant to the approved settlement agreement in Case No. U-21490, $27.5 million of the gain on the sale of the unregulated Appliance Service Plan ("ASP") business was used to reduce the required revenue requirement for that case. This base rate reduction does not carry forward to the test year of this case.

will pay approximately $2.94 per day in 2026 for the natural gas service that provides an affordable fuel for heating, cooking, and hot water.

The Company is aware that this increase will challenge some customers more than others. Recognizing the challenges some customers face, the Company offers a range of assistance options, including the Consumers Affordable Resource for Energy Program, a Residential Income Assistance credit, and a Low-Income Assistance Credit for qualifying customers. These programs are designed to assist customers with the management of their energy use and bills. In addition to these provisions and programs, the Company and its employees are generous contributors to community-based groups, including the United Way, the Salvation Army, the Heat and Warmth Fund, and many community service organizations. The Company works to keep its requested price increases to the lowest level it believes is reasonable, while balancing the need for safety, reliability, improved customer service, and increasingly clean natural gas service.

## INTRODUCTION OF WITNESSES

**Q. Please identify the other witnesses presenting direct testimony in support of the Company's filing and the topic that each witness will be addressing.**

A. The following witnesses will also be providing testimony on behalf of Consumers Energy in this filing:

- **Mustafa Ahmed** supports the Company's gas revenues and deliveries in the test year.
- **Stacy H. Baker** supports the IT Departments, capital expenditures, and O&M expenses that are needed to maintain existing IT systems, enable new security capabilities, and support other technology needs as proposed in the case. Ms. Baker also describes the Company's capital spending and O&M expenses related to cyber security operations and physical security, as well as the need for increased staffing and O&M to respond to evolving security threats and a changing regulatory landscape.

- **Corey Ballinger** describes the function and needs of the Company's fleet services and supports the fleet capital investment and electrification strategy.

- **Marc R. Bleckman** supports the Company's proposed capital structure and cost of capital which should be used in computing overall rate of return. Mr. Bleckman also provides support for the level of cash included in the Company's test year working capital.

- **Ann E. Bulkley** supports the Company's proposed return on equity that should be used in computing the overall rate of return.

- **Jessica Byrom** describes the work performed by the Company's Customer Experience & Operations organization and how this work benefits customers. Ms. Byrom also supports the capital investment and O&M expense associated with executing this work.

- **Amy M. Conrad** describes the Company's overall compensation philosophy and provides support for the recovery of costs related to the Company's annual Employee Incentive Compensation Program ("EICP") at target levels.

- **Neal P. Dreisig** provides an overview of the Company's gas transmission, distribution, and storage and compression systems along with an updated version of the Company's 10-year plan or the Natural Gas Delivery Plan ("NGDP").

- **Matthew J. Foster** supports the Company's Corporate Services O&M expense which includes uncollectible expense, and injuries and damages. Mr. Foster's testimony also supports Corporate Services capital spending, IT projects supporting Corporate Services, manufactured gas plant remediation cost recovery, and the request for certain accounting approvals.

- **Samuel M. Geller** sponsors the Company's gas cost of service study that conforms to methods previously approved by the Commission. He also provides a version of the cost-of-service study that incorporates Company proposals addressing cost of service study issues raised in Case No. U-21490.

- **Michael P. Griffin** supports certain gas transmission and distribution capital and O&M expenses primarily related to the operations of the Company's high-pressure distribution and transmission system.

- **Kendra K. Grob** supports the Company's costs related to retirement, health care, life insurance, long-term disability plans, and other benefits provided to its employees and retirees. Ms. Grob's testimony also supports the continuation of the Defined Benefit ("DB") Pension/Other Post-Employment Benefits ("OPEB") Volatility Mechanism.

- **Quentin A. Guinn** describes the function and needs of the Company's facilities and supports proposed capital spending and O&M expenses related to the Gas business portion of Facility Operations.

- **Kirkland D. Harrington** presents the Company's proposed tariff language changes to its gas rate schedules.

- **Timothy K. Joyce** supports the Company's Gas Compression and Gas Storage Capital spending and Gas Compression O&M expense. Mr. Joyce's testimony also sponsors IT projects supporting Gas Compression and Gas Storage, cost of gas sold and underground, lost and unaccounted for gas, and company use gas.

- **Ashley E. Meschke** discusses operational performance goals included in the Company's EICP and how the EICP goals provide benefits to customers.

- **Kristine A. Pascarello** supports Gas Engineering and Supply O&M expense as well as certain gas distribution capital investments.

- **James P. Pnacek** supports Gas Operations Division O&M expense as well as certain gas distribution capital investments. Mr. Pnacek also sponsors IT projects supporting the Gas Operations Division.

- **Heather M. Prentice** describes former manufactured gas plant sites at which the Company has a present or former ownership interest and provides environmental requirements for investigation and remediation. Ms. Prentice also identifies and describes expenditures for associated environmental response.

- **Heather L. Rayl** presents the historic and test year revenue deficiency. Ms. Rayl also presents support for requested approval to follow Federal Energy Regulatory Commission ("FERC") accounting treatment for first-time and one-time maximum allowable operating pressure retesting costs.

- **S. Austin Smith** presents the Company's rate design proposals.

- **Brian J. VanBlarcum** supports the Company's real and personal property taxes as well as the excess deferred federal income taxes being returned to gas customers because of the Tax Cuts and Jobs Act of 2017.

- **Lincoln D. Warriner** supports certain gas distribution capital investments related to the New Business, Asset Relocation, Regulatory Compliance, and Capacity/Deliverability programs.

**CASE HIGHLIGHTS**

**Q. How does the outcome of Consumers Energy's most recent gas general rate case impact the requested rate relief in this case?**

A. Consumers Energy's most recent gas rate case, Case No. U-21490, resulted in a Commission-approved Settlement Agreement with new rates that were implemented in October 2024. Consumers Energy continues to invest in its natural gas system and supporting infrastructure; therefore, this application includes the request to recover actual and projected costs related to these ongoing investments. As shown in Table 1, this request is largely driven by new investment.

**Q. Are there any provisions from the Settlement Agreement in Case No. U-21490 that impact this filing?**

A. Yes. The settlement agreement in Case No. U-21490 provided for the sharing of the net upfront gain from the sale of its unregulated Home Energy Products Program. $27.5 million, or one fourth of the net upfront gain, was used as an offset to the revenue deficiency in lieu of additional rate relief during the test year of Case No. U-21490. The remaining three fourths of the net upfront gain, approximately $82.5 million, will be credited back to customers, through the Home Products Credit over a three-year period extending through September 30, 2027. Company witness Smith sponsors the calculation of the credit to be effective on November 1, 2025.

The settlement agreement provided that the long-term service agreement ("LTSA") portion of the Home Products Credit could be modified in future rate cases. The Company has removed the LTSA margin from the Home Products Credit and has included it in base

rates. Company witness Byrom supports the margin included in the case related to the LTSA.

Company witness Pascarello's testimony and exhibits provide details regarding the Company's compliance with the settlement agreement's requirements regarding the Enhanced Infrastructure Replacement Program ("EIRP"). Her testimony discusses expectations of meeting the various spending requirements based on region and the type of pipe used for replacements.

Company witness Geller sponsors a Cost-of-Service study version that shows a more granular allocation of Other Distribution Plant by FERC account and a cost-of-service version that calculates the impact of utilizing the Average and Excess allocation. Mr. Geller's testimony also includes a detailed analysis of FERC Account 378, as required by the settlement agreement.

Company witness Smith explains how the Company is complying with the requirement to examine the breakeven points and bring the breakeven points and the customer charges closer to cost of service.

**Q. How do the Company's proposals in this case support the Company's NGDP?**

A. Consumers Energy has plans for investing in its natural gas system over the course of the next decade to ensure customers continue to receive safe, reliable, and affordable natural gas while transforming the system to deliver cleaner fuels for a decarbonized future. The NGDP outlines the Company's 10-year plan to provide a transparent investment plan considering a safe and reliable gas supply, how the Company plans to evolve its assets in accordance with the Gas Pipeline Safety Management Systems framework, and a strategic framework in response to decarbonization goals of the Company's natural gas customers

and future carbon policy relevant to the utility. The proposals in this rate case support the objectives of the NGDP. Company witnesses Dreisig, Joyce, Griffin, Warriner, Pascarello, and Pnacek provide support for the transmission and distribution system investments and O&M programs.

**Q. Why is Consumers Energy making significant natural gas investments?**

A. Consumers Energy has built and maintained a complex natural gas system comprising of approximately 30,700 miles of distribution and transmission pipelines. The Company operates 15 storage fields and 8 compressor stations, and all of these systems have served customers well for decades, allowing access to a diverse natural gas supply and leveraging the unique size of the Company's storage fields to time gas purchases and stabilize pricing. It is crucial that Consumers Energy continue to invest in the system to ensure natural gas is delivered safely, reliably, and affordably to the approximately 1.8 million natural gas customers who rely on it every day.

**Q. How should stakeholders view the Company's natural gas investment?**

A. Consumers Energy's investment represents its commitment to modernizing the Company's natural gas pipelines and continued improvements in energy efficiency. The EIRP continues to replace significant portions of the Company's infrastructure annually, resulting in a safer, more resilient system that has fewer leaks, thereby reducing carbon emissions. Additionally, the Company continues to work with third parties through its damage prevention program and third-party coordination efforts to mitigate and reduce third party-caused leaks on the system. The investments, outlined in the NGDP, express the multitude of initiatives the Company is undertaking to ensure the sustainable delivery of safe, reliable, clean, and affordable energy to customers.

**Q. Is the Company proposing any deferrals related to critical gas operation costs?**

A. Yes. As detailed in the testimony of Company witnesses Pnacek and Pascarello, the Company is requesting the ability to defer any test year revenue requirement of capital and O&M expense that occur as a result of updates to Leak Detection and Repair rules and requirements to comply with the Pipeline and Hazardous Materials Safety Administration ("PHMSA"). The Company anticipates requirements to comply with PHMSA that relate to safety and reporting. These rules are expected to be updated after the filing of this application and will require repairs and upgrades to be completed during the test year.

Consumers Energy also proposes to defer O&M spending related to staking. While the Company attempts to forecast staking volumes with a high degree of accuracy, increasing staking volumes and external factors contribute to volatile expenditures. This request would avoid potential constraints on other important programs in the event higher than anticipated staking costs outside of the Company's control are incurred. Company witness Pnacek also addresses this topic in his testimony.

**Q. How do IT and security proposals provide value to customers?**

A. As described in more detail below, the Company is beginning a critical upgrade to its SAP system that has a direct tie to being able to keep Company and customer information safe and secure. In addition to investments in IT, the Company proposes continuing investments in the Security Department's ability to provide 24/7 physical and cyber security to ensure protection for the Company's critical infrastructure and maintain customers' privacy by keeping their sensitive data safe. Security risks to the Company have never been greater, and the Company must keep pace with the rising threats to maintain essential services and recover quickly in the event of a security incident. The

Company is improving its focus on security across its operations with increased staffing levels to support 24/7 security monitoring through the Fusion Center — a dedicated team with oversight for physical and cyber security, increased use of cloud computing solutions, and ongoing investment in maturing security capabilities to protect technology and physical infrastructure. Company witness Baker addresses the Company's proposals for security and IT.

**Q. Does the Company evaluate major capital projects and O&M expenses on an ongoing basis?**

A. Yes. The Company continually evaluates and adjusts its planning for a variety of factors including (i) sales and revenue expectations and results, (ii) infrastructure investments and the cost of capital, (iii) O&M expense expectations and results, and (iv) the impact of several other variables that may change over time (including changes to environmental laws and requirements, Commission orders, weather, customer demands, commodity prices, financing costs, changes in economic expectations, etc.). In any one period, the Company's capital investments and its O&M expenses may vary from what was expected in a prior period. The Company plans for this continually changing environment, and its witnesses have provided highly detailed and thorough support for capital expenditures and O&M expenses.

The individual witnesses addressing capital and O&M costs in this case explain the reasons for these expenditures. The Company employs a rigorous management review process, which ensures that the allocation of O&M and capital resources are optimized such that the Company's strategic, financial, and operational plans are aligned to deliver customer value. The Company maintains a portfolio of investment opportunities from

which to make investment decisions, with the goal of maximizing customer value while minimizing the cost impact to customers. While the Company must retain the flexibility to react to changing conditions, the proposed expenditure levels included in this case reflect the Company's commitment to meet its legal obligations and improve service reliability and quality for customers.

**Q. Does the Company anticipate the need to flex spending between programs in the test year?**

A. Yes. The Company's plans provide its best estimate of the total cost it expects to spend on each program. However, when actual dollars are spent in the test year, unforeseen circumstances (such as new business, extreme weather, or unanticipated civic improvement projects undertaken by state or local governments, for example) may require the Company to adjust the spending between programs. In any given year, the Company may be required to undertake unplanned natural gas distribution infrastructure replacement projects. In this circumstance, the Company would need to compensate for this unforeseen spending by adjusting the amount it intended to spend on another program. It is not possible for Consumers Energy to anticipate every event or circumstance which may cause it to incur costs on behalf of its customers, so it is prudent to allow for some flexibility in spending.

**Q. Is the Company requesting to continue a DB Pension/ OPEB Volatility Mechanism?**

A. Yes. DB Pension/OPEB expenses are sensitive to changes in asset returns or other assumptions that create a significant potential for volatility in future expenses. As discussed in the testimony of Company witness Grob, the Company is requesting the ability to continue its currently in place mechanism which provides benefit to customers by eliminating the risk of future expense volatility.

**SAP S/4HANA IMPLEMENTATION PROJECT RECOVERY**

**Q. Describe the SAP Project.**

A. The SAP Project will modernize the Company's current Enterprise Resource Planning SAP solution that will reach the end of mainstream vendor maintenance on December 31, 2027. The completion of this project is crucial. Operating the system beyond the end of support date creates significant risks including the inability to comply with regulatory mandates, perform core customer supporting business operations, and apply the latest security patches that are critical for cyber security protection. The project is described in more detail in the testimony of Company witness Baker.

**Q. Please describe amounts included in this rate case related to the SAP Project.**

A. The Company has [redacted] of test year capital spending to [redacted] of O&M expense in the case. None of the capital spending will result in plant in service during the test year of this case. As a result, the case does not include any of the associated depreciation expense and the return on amounts included in construction work in progress have been offset by allowance for funds used during construction. Simply put, there is no financial impact to the case resulting from the capital spending. The O&M expense has a dollar for dollar or [redacted] impact on the revenue deficiency.

**Q. How does the Company propose to address the O&M expense for this project?**

A. The Company is proposing to defer the associated O&M expense for the project and amortize it over 15 years consistent with the life of the assets. This approach will prevent the need for customers to fund spikes in the Company's IT O&M expense during the project and will instead smooth the collection over the life of the asset. The deferral will also tie the recovery to the time period over which the spending will be providing benefits

to the Company and customers. This is the most appropriate method of recovering the O&M expense related to the SAP project.

**Q. If the proposed deferral is approved how will the case be impacted?**

A. If the deferral is approved, the revenue deficiency of the case should be lowered by [redacted]. As shown on Confidential Exhibit A-79 (HJM-1), this reduction includes the removal of the O&M expense replacing it with the inclusion of the expense as a deferral in working capital.

**Q. Does the implementation of this deferral require any specific accounting approvals?**

A. Yes. The proposed deferral would result in deferred debits to be amortized over 15 years. The Company requests approval to recognize a regulatory asset to record these deferred expenses.

**Q. Are there are any other requests related to the SAP Project?**

A. Yes. The Company also requests a 15-year amortization for the cloud implementation costs for the SaaS solutions to create consistency of recovery for all aspects of the cost of the SAP Project. This would lengthen the amortization period from being tied to the duration of the initial license to the life of the asset that anticipates relicensing over the life of the asset. This provides customer benefit by spreading these costs over a longer period and matching the recovery to the period over which this spending will provide benefit to the Company and customers.

**Q. Please summarize your direct testimony.**

A. Consumers Energy respectfully submits this request for $248 million in annual rate relief. Consistent with Consumers Energy's commitment to provide exceptional value and service to every customer, caring for the communities where we live and work, and delivering on

investor expectations, the Company is requesting revenue recovery for infrastructure investments that primarily support the NGDP, as well as other programs that will enhance the customer experience. Consumers Energy is committed to delivering customer value and improving customer service and believes that this filing is a representation of the commitment put forth in the Company's purpose – World Class Performance Delivering Hometown Service.

**Q. Does this complete your direct testimony?**

A. Yes.

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

| | | |
|---|---|---|
| In the matter of the application of<br>**CONSUMERS ENERGY COMPANY**<br>for authority to increase its rates for the<br>distribution of natural gas and for other relief | )<br>)<br>)<br>)<br>) | Case No. U-21806 |

**REBUTTAL TESTIMONY**

**OF**

**HEIDI J. MYERS**

**ON BEHALF OF**

**CONSUMERS ENERGY COMPANY**

May 2025

**Q. Please state your name and business address.**

A. My name is Heidi J. Myers, and my business address is One Energy Plaza, Jackson, Michigan 49201.

**Q. Are you the same Heidi J. Myers who previously presented direct testimony in this case on behalf of Consumers Energy Company ("Consumers Energy" or the "Company")?**

A. Yes.

**Q. What is the purpose of your rebuttal testimony?**

A. I will rebut certain assertions and recommendations of the Association of Businesses Advocating Tariff Equity ("ABATE") witness Jessica A. York and the Citizens Utility Board of Michigan ("CUB") witnesses Ram Veerapaneni and Richard J. Bunch regarding the use of a projected test year and productivity assumptions. I will also address ABATE witness Colin T. Fitzhenry's position taken on inflation. In addition, I will also address Attorney General Dana Nessel ("AG") witness Sebastian Coppola regarding his proposed Operating and Maintenance ("O&M") adjustments related to the Company's Voluntary Separation Program ("VSP"), his proposed adjustments related to the Riverside Storage Field, and his recommendation related to the accounting for the SAP S4/HANA project.

**Q. Have you prepared any exhibits in conjunction with your rebuttal testimony?**

A. No.

**Q. Are there any statements you would like to make regarding your rebuttal testimony?**

A. Yes. Any items not specifically addressed in my rebuttal testimony does not indicate my agreement with them.

**Test Year**

**Q. Has the Michigan Public Service Commission ("MPSC" or the "Commission") previously approved Consumers Energy's ability to utilize a Projected Test Year?**

A. Yes, the Commission has, for many years, approved the use of projected test years. Most recently in Consumer Energy's electric rate case, Case No. U-21585, the MPSC's March 21, 2025 Order once again approved the use of a projected test year despite being presented with the same arguments from intervening parties that will be addressed in this rebuttal testimony.

**Q. What specific guidance did the Commission provide in Case No. U-21585?**

A. The Commission "…acknowledges that the use of projected test years by utilities in developing requested rates in rate cases is permissible by statute – subject, however, to the burden that the company prove the accuracy of each and every test year projection." The Commission further opines "… the Commission agrees with the ALJ that "the burden of proof to substantiate projections lies with the utility, and absent sufficient support, historical data may be used to develop the revenue requirement," that "the used and useful standard should be applied on a case-by-case basis," and that "Consumers' projected test year should be adopted in this case, with costs and revenues adjusted based on the preponderance of the evidence." See MPSC Case No. U-21585, March 21, 2025 Order, page 9.

**Q. Does ABATE witness York propose to deviate from the Commission's long-standing approval of the use of projected test years?**

A. Yes. Starting on page 8 of her direct testimony, Ms. York asserts that all cost projections should be based on historical test year amounts with costs adjusted for known and

measurable changes, but goes on to recommend no rate increase for this case without providing for any known and measurable changes.

**Q. What examples does Ms. York provide for known and measurable changes to a historical test year?**

A. On pages 8 and 9 of her direct testimony, Ms. York provides four examples of what she considers valid known and measurable changes to a historical test year. They include normalizations to address the effects of volatility, annualization of costs that occur on a periodic basis, but not in every year, annualization of costs that occurred in the later months of the historical year that are expected to continue at that level going forward, and imminent changes in costs that will occur during the period between the end of the historical period and the date new base rates go into effect.

**Q. Has Ms. York incorporated her thoughts on valid known and measurable changes in her recommendation to the Commission?**

A. She has not. Ms. York did not propose any modifications to the historical test year that she perceives as valid known and measurable adjustments. Her ultimate recommendation to the Commission to have no rate increase based on the results of the historical test year deviates from her own thoughts on the appropriate method to set rates. This alone is reason enough to reject Ms. York's recommendation.

**Q. Do you agree with ABATE witness York's rationale for moving away from the long-standing Commission approved use of projected test years?**

A. No. The following testimony will individually address each of the points made by Ms. York.

**Q. Please comment on Ms. York's assertion on page 6 of her direct testimony that customers experience rate increases sooner using a projected test year than they would under a historical test year.**

A. The use of a projected test year provides the calculation of rates necessary during the period for which the rates will be in effect. This is the most accurate way to set rates and, as will be discussed further below, provides intervenors with an opportunity to comment on the Company's plans for spending prior to the dollars actually being spent. Not only does Ms. York's assertion ignore these points, it identifies a fact, that if acted upon by the Commission, would unfairly remove the fundamental ability of the Company to have an opportunity to earn a fair rate of return on its investments and knowingly provide customers rates that are below the cost to serve them.

**Q. Do you agree with Ms. York's assertion on page 7 of her direct testimony that a projected test year eliminates cost containment?**

A. I do not. The Company has an incentive to hold spending at levels approved in rates and work to spend efficiently. Once rates are established, the Company is left to manage the business within those rates inclusive of risks that are outside the control of the Company such as weather impact on sales. This provides a powerful incentive for cost containment.

**Q. Do you agree with Ms. York's assertion on page 7 of her direct testimony that the use of a projected test year handicaps Staff and intervenors in reviewing Consumers Energy's rate filings to ensure the projected capital expenditures and expenses are reasonable because they are not actual capital expenditures?**

A. I do not. Providing expected spending for a future test year provides a more transparent rate making process allowing Staff and intervenors an opportunity to understand how dollars

are intended to be spent and opine on the merits of the proposed spending. In comparison, setting rates based on historical spending is inferior as it only allows for review of spending after it has already occurred. This can have unfortunate consequences. If spending is only reviewed after it is spent and only then determined to be an item that should be disallowed from rates, it can lead to write-offs for the Company and an inefficient use of a finite amount of dollars available to invest in the system. This is not good for the Company or customers. Customers are better served by the rate setting process provided by projected test years that allows parties to the rate case proceedings an opportunity to understand and opine on the merits of how dollars will be spent in advance of the spending.

**Q. On page 6 of Ms. York's direct testimony, she has included Table JAY-2 titled Historic Test Year and Projected Test Year Rate Sufficiency/(Deficiency). Do you agree with the conclusion that Ms. York reached as a result of the data on this table?**

A. I do not. Ms. York's assertion based on the table is that the Company "…would not have been able to seek the large rate increases it has sought in seven out of its eight most recent rate cases, including this proceeding, but for basing the requested rate increases on projected test years." While it may be true that rate requests would be different if the Company were required to rely on a historical test year for rate relief, it would not remove the need for rate relief but would only unfairly delay it. In fact, the very first time rates were established rates on a historical test year it would create a greater deficiency in the next historical year requiring a greater increase in that year. This does not create a regulatory environment conducive to customer interest. ABATE's request to rely on historical test years for setting rates is really an ask to trade an environment where stakeholders and the Commission have an opportunity to weigh in on spending, projects, and programs before they are implemented

for a short-term and inappropriate delay in rate relief. Establishing a built-in regulatory lag as proposed by Ms. York would be detrimental to the Company and its customers, and is inconsistent with the Michigan Law providing for rates to be set using projected test years.

**Q. Pages 12 through 13 of Ms. York's direct testimony provides what she labels as her longer-term recommendation to the Commission. How do you respond?**

A. In that portion of her direct testimony, Ms. York describes other filings and dockets where ABATE has opined on test years. This portion of her testimony has either already been addressed by the Commission or will be addressed by the Commission in those other dockets.

**Q. Have any other witnesses commented on the use of a projected test year?**

A. Yes. CUB witness Veerapaneni recommends moving away from a projected test year. He recommends the use of an average of 2023 and 2024 historical data for capital and O&M expense for the case. He indicates that the cycle of annual rate case filings never ends if the MPSC approves even a small portion of the increase and goes on to note that Consumers Energy has the responsibility to provide safe and reliable utility service because Consumers Energy does not have competition to provide gas service. He requests the Commission consider customer's inability to look for other sources of gas and use average historical data for capital and O&M expense.

**Q. Please respond.**

A. I do not agree with Mr. Veerapaneni's request or reasons for the request. First, Mr. Veerapaneni did not review the Company's capital or O&M expense projects. His testimony described several capital and O&M programs but did not provide any critique of

the proposed spending or rationale as to why the spending was not reasonable or prudent. On one point, I do agree with Mr. Veerapaneni. Consumers Energy is obligated to provide safe and reliable utility service. The testimony of Company witnesses provides support for the needed capital and O&M spending included in the case to do just that. Mr. Veerapaneni does not make any assertions that the Company has not adequately supported the costs included in this case and he does not provide any clear evidence as to why an average of 2023 and 2024 historical spend as the basis for the entirety of capital and O&M expenditures is appropriate. As such, Mr. Veerapaneni's request to base all capital and O&M expense on historical experience is not appropriate and should be rejected by the Commission.

**Productivity Factors**

**Q. Please describe CUB witness Bunch's recommendation related to the use of a productivity factor in this case.**

A. On pages 13 through 23 of his direct testimony, CUB witness Bunch supports his recommendation that the Commission apply a productivity adjusted inflation factor to all actual historical O&M and capital project labor costs to determine test-year spending projections. Mr. Bunch also recommends the same treatment for non-labor costs, both O&M and capital. He indicates that the inflation rates supported by the Company should be reduced by a 0.79% productivity factor based on the average annual Michigan labor productivity factor and applied to historical labor costs and he recommends reducing inflation rates by a 0.83% productivity factor based on the non-labor total factor productivity factor to be applied to non-labor O&M and capital. Ultimately, he argues that rates that rise at the rate of inflation are not justified because inflationary pressures on costs should be mitigated by gains in productivity and the Company should be able to fully

recover its costs with rates that rise slower than inflation if it realizes productivity gains. He goes on to argue that utilities do not face competitive pressures to contain costs and a reasonable opportunity to recover their costs should include a reasonable expectation that it demonstrate over time that it is attaining productivity gains comparable to those of companies operating in competitive markets.

**Q. Do you agree that projected test year costs should be determined based on historical amounts increased by inflation that has been reduced by a productivity factor?**

A. No. The Company strives to continuously improve through its CE Way Operating System that identifies and executes on productivity improvements leveraging new technology and sustainable productivity improvements to help mitigate inflationary pressure and control costs over time. All known cost reductions related to productivity are incorporated in financial exhibits of each witness. Mr. Bunch's recommendation to determine projected test year costs by applying a productivity-adjusted inflation factor to historical actual costs is overly simplistic and does not align with the reality of the costs the Company is experiencing or expects to experience. The standard that must be applied to the projected costs is whether they are reasonable and prudent. Broad productivity adjustments do not meet this standard. If the Commission were to simply apply cost indexes to historical costs, there would be no need for any evidence to be presented in the contested case. Further, Mr. Bunch's recommendation removes the ability for the Company to utilize a projected test year. As noted above, the Commission has indicated numerous times that a projected test year is permissible by statute, and it is the Company's burden to support its rate case projections. The Company witnesses fully support the projected test year costs they sponsor. Any adjustments should be based on the merits of the specific costs in question.

**Q. Please respond to Mr. Bunch's conclusion at page 17 of his direct testimony that utilities do not face competitive pressures to contain costs and a reasonable opportunity to recover its costs should include a reasonable expectation that it demonstrate over time that it is attaining productivity gains comparable to those of companies operating in competitive markets.**

A. As noted above, I do not consider this an appropriate consideration in determining proper rates. However, even it were, the Company has in fact demonstrated over time that its rates have remained lower than inflation. Company witness Neal P. Dreisig provides testimony that over the past 10 years customer bill increases are well below inflation.

**Q. Mr. Bunch also indicates that the Company's costs must be increasing at rates higher than inflation because the proposed rate increase is higher than inflation. Please respond.**

A. Mr. Bunch has not considered all necessary facts to make this assertion. He went on to discuss only the changes in O&M expense when trying to connect cost increases to the proposed rate increase. However, changes in O&M expense only explains 17% of the proposed increase or a 1.8% increase which is lower than inflation. The largest driver of the proposed increase is the needed investments in the system which represents additions of capital assets and are not necessarily indicative of a rise in costs. They represent additions of assets that serve customers and are supported in great detail by other Company witnesses.

**Q. Has Mr. Bunch provided evidence that the productivity factors are appropriately applied to costs incurred by the Company?**

A. No. Mr. Bunch provided no explanation of how his suggested productivity factors are calculated or used in practice, nor did he provide compelling evidence that they would be

appropriately used to set utility rates. The U.S. Bureau of Labor Statistics ("BLS") indicates that labor productivity is equal to output divided by hours worked and the total factor productivity is equal to output divided by combined inputs.[1] Mr. Bunch's broadbrush proposal to apply productivity factors to all capital and O&M costs ignores the fact that the Company does not have control over all costs and may have less control over the inputs used to calculate the productivity factors than other companies. Any recommended adjustments to projected costs should be based on the merits of those specific costs.

**Q. CUB witness Bunch also recommends that the Commission replicate the order it issued in Consumers Energy's electric rate case, Case No. U-21585, namely that it should direct Consumers Energy to present more detailed evidence to demonstrate that it is in fact offsetting inflation by productivity in the Company's next gas rate case. Do you agree with this recommendation?**

A. No. In each rate case the Company must demonstrate that its costs are reasonable and prudent. The Company strives to continuously improve its efficiency through the CE Way Operating System and incorporates known savings in its financial exhibits. However, accurately measuring productivity gains that accumulate over time and pointing to a specific spending line item in the case that is impacted can be complex. Productivity as defined by the BLS, is outputs divided by inputs. Trying to identify each and every change in either outputs or inputs in the context of productivity as part of a regulatory filing would be overly burdensome. The Company understands its obligation to provide clear cost projections along with support for the reasonableness of its projections and responds to feedback received in Commission orders. Requesting more information on specific cost items, if

[1] https://www.bls.gov/productivity/educational-material/labor-productivity-total-factor-productivity-comparison.htm

needed, is a more constructive request than requesting an overly complex isolation of all productivity included in the case.

**Q. Does Consumers Energy agree that the Company must support all costs included in its rate cases?**

A. Yes. It is on this basis that I again respectfully requesting the Commission reject the recommendations of ABATE witness York and CUB witnesses Bunch and Veerapaneni to leverage either a productivity factor, historical based capital and O&M costs, or outright rejection of using a projected test year as a means to disallow projects without deeper consideration. Disallowances for all projects and programs in this manner would disregard the evidence provided by the Company witnesses in support of the reasonableness and prudence of investments. The Company requests the Commission continue to evaluate each proposed project on its individual merits in the instant case to determine its reasonableness and prudency.

**Inflation**

**Q. Describe ABATE witness Fitzhenry's proposal related to inflation.**

A. At pages 18 and 19 of his direct testimony, Mr. Fitzhenry proposes to use the Blue Chip GDP Chained Price Index ("Chained Price Index") as a replacement for the Consumers Price Index ("CPI") that the Company used in the case. Mr. Fitzhenry argues that the basket of goods in the Chained Price Index is updated each year to reflect what people are actually buying. He goes on to say that this is unlike the CPI, which uses a fixed basket for a set period. He also provides an analysis showing that there is a higher correlation to the actual cost of gas meters for the Chained Price Index than the CPI. Ultimately, he recommends the Commission replace the CPI with the Chained Price Index indicating that the CPI

non-labor inflation rate is well above the consensus industry experts' opinion of the Chained Price Index.

**Q. Please respond.**

A. As will be illustrated, there are numerous issues with the conclusions drawn by Mr. Fitzhenry. The Commission should maintain its long-standing practice of approving the use of CPI in rate cases.

**Q. Do you agree with Mr. Fitzhenry's assessment at page 18 of his direct testimony that the CPI is inferior to the Chained Price Index because the Chained Price Index is updated annually?**

A. I do not. The CPI is updated periodically. The BLS indicates that these updates are made to "reflect more recent consumer spending patterns; this provides a logical opportunity to rework the item classification scheme so that it will recognize the emergence of new items, the changes to existing items and their relative importance, and the ways that people view consumer goods and services."[2] As such, the CPI should not be viewed as inferior to the Chained Price Index because the Chained Price Index is updated annually.

**Q. Should Mr. Fitzhenry's correlation analysis be considered in deciding the appropriate inflation index for this case?**

A. No. Starting on page 19 of his direct testimony, Mr. Fitzhenry did an analysis to find the correlation for one expense item, gas meters, to the CPI and the Chained Price Index finding that there was a higher correlation to the Chained Price Index. However, the nature of both of the indexes is to provide inflation rates for a basket of goods, not just one item. It is not

[2] https://www.bls.gov/cpi/additional-resources/revision-1998-item-structure.htm

appropriate to draw the conclusion that the Chained Price Index is more appropriate than the CPI based on a correlation review of one expense item.

**Q. Mr. Fitzhenry ultimately concludes that the Commission should adopt the Chained Price Index for inflation in this case also indicating that its use is a consensus industry opinion. Does he explain what a consensus industry opinion represents?**

A. No. Mr. Fitzhenry does not explain what a consensus industry opinion represents and provides no proof or support that this is true. This unsupported assertion should be disregarded.

**Q. Is there a long standing practice for Commission approval of the CPI for use in rate cases?**

A. Yes. The Commission has consistently approved the use of CPI. The Commission most recently approved the use of CPI in DTE Electric Company's rate case, Case No. U-21534. At page 76 of the January 23, 2025 Order the Commission stated:

> The Commission also rejects the proposal to switch to use of the Real GDP Chained Price Index. As the company points out, the CPI is the most widely used measure of inflation, and the Commission finds ABATE failed to show how the Real GDP Chained Price Index is superior to the CPI-Urban for either labor or non-labor costs or why the Real GDP Chained Price Index's customer substitution treatment is superior to the periodic updates made in the CPI's basket of goods.

The facts in this case are similar and Mr. Fitzhenry has not provided adequate support to move to the Chained Price Index. The Commission should approve the continued use of the CPI for inflation.

**Voluntary Separation Program**

**Q. Can you summarize the testimony and recommendations of AG witness Coppola regarding the Company's 2023 VSP?**

A. AG witness Coppola proposed adjustments in the amount of $7,989,000 related to the Company's 2023 VSP. On pages 181 and 182 of his direct testimony, he indicates that the Company did not provide any underlying calculations showing how the cost savings were calculated or any supporting schedules that would show the cost savings were actually included in the projected test year in each exhibit for the affected departments. His ultimate recommendation is for the Commission to remove the entire $7,989,000 of VSP savings from the Company's forecasted O&M expense for the projected test year.

**Q. Please respond.**

A. The Company did not provide a calculation of the savings because the savings provided are actual amounts. Through discovery, the Company disclosed the number of employees by area and the dollar value of the savings associated with these employees leaving the Company. The Company was also not able to provide specific workpapers that identify these VSP savings in each witness exhibit. However, this is for good reason. With the exception of Company witness Matthew J. Foster who sponsors corporate O&M expense, O&M witnesses include total projected O&M expense based on the forecasted needs in their business area. When considering those needs for the projected period of this case, each witness had knowledge and used the knowledge of the VSP savings when developing their O&M expense for the case. Company witness Foster does forecast corporate O&M by inflating historical O&M expense. However, he also removed VSP savings from the historical year prior to inflating the historical O&M expense. All of the VSP savings were

considered in the development of this case and have been properly incorporated. It is not appropriate to remove the VSP savings as recommended by Mr. Coppola.

**Accounting For SAP S4/HANA**

**Q. Please describe AG witness Coppola's recommendations regarding the SAP S4/HANA project.**

A. At page 91 of his testimony Mr. Coppola indicates that the project is too premature to include any capital expenditures in this rate case and to defer large forecasted O&M costs in a regulatory asset without firm plans for project execution. Again on page 180 of his direct testimony, he recommends the denial of the proposed regulatory asset accounts related to the SAP S4/HANA project relying on his assertions that the project is premature and inadequately justified and all requested approvals related to the project should be denied.

**Q. Does the Company agree that SAP S4/HANA costs should not be included in this case?**

A. No. Company witness Stacy H. Baker provides continued support for the inclusion of the SAP S4/HANA project in her rebuttal testimony.

**Q. Do you agree with Mr. Coppola that the accounting requests related to the SAP S4/HANA project should be denied?**

A. No. As explained in my direct testimony, approval of the deferral of the O&M expense associated with the project will allow the Company to spread the O&M costs of the project over the life of the assets resulting from this project tying the recovery of the expense to the time period over which the spending will be providing benefits. This is also true for the request to extend the amortization period over which the cloud implementation costs for the SaaS solutions to 15 years. These requests reduce the burden to customers, avoid spikes in

IT O&M expense and the need for customers to experience those spikes in rates. Mr. Coppola does not provide any critique of these accounting requests other than his assertion that the project is too preliminary for it to be included in this case. Company witness Baker has proven this to be incorrect. As such, the Commission should approve the inclusion of the SAP S4/HANA project and the associated accounting requests.

**Riverside Storage Field**

**Q. Please describe AG witness Coppola's adjustments related to the Riverside Storage Field.**

A. At pages 108 and 174 of his direct testimony Mr. Coppola has recommended removing the regulatory asset in working capital and amortization associated with the sale of the Riverside Storage Field indicating that the expected sale was terminated by the buyer.

**Q. Does the Company agree with these adjustments proposed by Mr. Coppola?**

A. Yes. However, if the amounts associated with the sale are removed from the case based on the assumption that there will not be a sale of the Riverside Storage Field, the plant assets should be added back into the case.

**Q. Please explain further.**

A. Consistent with Staff witness Robert F. Nichols' recommendation beginning at page 5 of his direct testimony, if the effects of the Riverside Storage Field sale are removed from the case the plant in service, depreciation reserve, depreciation expense, and property tax should be added back in. If the Riverside Storage Field assets are not sold, the cost associated with the assets should be included in rates. Mr. Nichols went on to support a recommendation provided by the Company in response to an audit question. This recommendation is to use any amount collected in rates related to the Riverside Storage Field assets as a reduction to

the established regulatory asset related to the sale, in the event that the Riverside Storage Field is sold. The Company agrees with Staff's position in the case related the Riverside Storage Field.

**Q. How should the Commission treat Mr. Coppola's proposed adjustments?**

A. The Commission should only adopt Mr. Coppola's proposed adjustments to working capital and amortization expense related to the Riverside Storage Field if there are also adjustments made to plant in service, depreciation reserve, depreciation expense, and property tax to add the Riverside Storage Field back into the case consistent with Staff's adjustments in the case.

**Q. Does this conclude your rebuttal testimony?**

A. Yes.

MR. RUSZKIEWICZ: The Company's next witness is James P. Pnacek. Based on the stipulation of the parties, the Company moves to bind in the testimony of witness Pnacek, which consisted of direct testimony, a cover page plus 95 pages of prefiled testimony. This was filed as revised testimony. The witness also had rebuttal testimony, a cover page, and 19 pages of prefiled testimony.

The Company also moves to admit the exhibits of Mr. Pnacek, which are labeled as A-86, A-87, A-88, A-89, confidentially filed A-143, confidentially filed A-144, A-145, and that's it. Thank you.

JUDGE VARCHETTI: Are there any objections to the binding in of Mr. Pnacek's revised direct and rebuttal testimony or any of his associated exhibits?

Hearing none, the testimony is bound into the record and the exhibits are admitted.

MR. RUSZKIEWICZ: Thank you, Your Honor.

(Rebuttal Confidential Testimony Bound in in Confidential Record)

(Revised Direct and Rebuttal Testimony bound in)

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

| | | |
|---|---|---|
| In the matter of the application of **CONSUMERS ENERGY COMPANY** for authority to increase its rates for the distribution of natural gas and for other relief. | ) ) ) ) ) | Case No. U-21806 |

# REVISED DIRECT TESTIMONY

# OF

# JAMES P. PNACEK, JR.

# ON BEHALF OF

# CONSUMERS ENERGY COMPANY

December 2024

**Q. Please state your name and business address.**

A. My name is James P. Pnacek, Jr., and my business address is 1945 West Parnall Road, Jackson, Michigan 49201.

**Q. By whom are you employed and in what capacity?**

A. I am employed by Consumers Energy Company ("Consumers Energy" or the "Company") as a Principal Strategy Analyst.

**Q. What are your responsibilities as Principal Strategy Analyst?**

A. In addition to being a rate case witness, I am responsible for performance-based and Lean initiatives. I support the Company's Gas Strategy, which includes the development, recommendation, and administration of the Natural Gas Delivery Plan ("NGDP").

**Q. Please describe your educational background.**

A. I received a Bachelor of Science degree, with Honors, in Mechanical Engineering from Michigan State University in 1992.

**Q. Please describe your business experience.**

A. I joined Consumers Energy in 1992 as a Graduate Engineer in the Natural Gas Compression Department, where I was responsible for providing project management and operational support to the Company's seven compressor stations. I transferred to the St. Clair Compressor Station in 1996, where I supervised operations and maintenance employees, and had responsibility for operating and maintaining the Station. In 1998, I joined the Gas Operations Technical Support Department where I was responsible for the Gas Transmission and Storage capital budget and prioritization of the capital projects. In 2001, I joined the Gas Engineering, Regulatory, and Operating Services - Codes and Standards Group.

In this position, I was Chairman of the Gas Transmission and Storage Standards Committee, responsible for maintaining the Michigan Gas Safety Code-based standards and addressing Michigan Gas Safety Code compliance questions. In 2005, I transferred to the Electric Generation Operations Department. In this position, I was responsible for implementing and managing a Health and Safety Compliance program for Consumers Energy's electric generating plants. In 2008, I joined the Gas System and Operations Planning section of Gas Management Services and was responsible for the Gas Cost Recovery ("GCR") purchase recommendations and management of Storage Field Inventory. I assumed my current duties and responsibilities in Gas Strategy in September 2021.

**Q. Have you previously testified before the Michigan Public Service Commission ("MPSC" or the "Commission")?**

A. Yes. I have filed testimony and/or testified in GCR Reconciliation Case Nos. U-16924-R, U-17133-R, U-17334-R, U-17693-R, U-17943-R, U-20075, U-20209, U-20233, and U-20542. I have also filed testimony in Gas Rate Case No. U-21490 and End-Use Transportation proceeding in Case No. U-17900.

**Q. What is the purpose of your direct testimony in this proceeding?**

A. My direct testimony provides a detailed description of the projected Operating and Maintenance ("O&M") expenses for the Company's Gas Operations Division that are necessary to allow the Company to meet public safety, compliance, and operating requirements, while delivering an excellent level of service to customers. I will explain the Company's Gas Operations Division O&M expenses for the projected test year 12 months ending October 31, 2026, to be referred to as "test year" or "2025 – 2026 Test year" in my

testimony. My direct testimony is divided into two parts: (i) Gas Operations O&M expenses and (ii) Information Technology ("IT") projects.

**Q. Are you sponsoring any exhibits with your direct testimony?**

A. Yes. I am sponsoring the following exhibits:

| | |
|---|---|
| Exhibit A-86 (JPP-1) | Summary of Actual & Projected O&M Expenses: Operations, Maintenance & Metering, Field Services, Other Operations; |
| Exhibit A-87 (JPP-2) | Summary of Actual & Projected O&M Expenses: Operations, Maintenance & Metering Programs; |
| Exhibit A-88 (JPP-3) | Summary of Actual & Projected O&M Expenses: Field Operations Services; and |
| Exhibit A-89 (JPP-4) | Summary of Actual & Projected O&M Expenses: Other Operations. |

**Q. Were these exhibits prepared by you or under your direction or supervision?**

A. Yes.

**GAS OPERATIONS O&M EXPENSES**

**Q. Please describe the Gas Operations Division.**

A. The Gas Operations Division is committed to meeting the needs of Consumers Energy's natural gas customers through the delivery of services in a safe, reliable, cost-effective, and timely manner. The division manages the routine, ongoing customer-facing operations and maintenance of the Company's distribution and transmission systems. The O&M expenses for Gas Compression will be covered in Company witness Timothy K. Joyce's testimony. The Gas Operations Division manages the O&M programs described more fully below.

**Q. What are the major O&M programs that are managed within the Gas Operations Division?**

A. The four major O&M programs within the Gas Operations Division are as follows:

1. Operations, Maintenance, and Metering
2. Field Operations Services
3. Work Management and Customer Delivery
4. Operations Management

**Q. Were there any changes to the major O&M programs within the Gas Operations Division for this case?**

A. Yes. The Operations Performance program that was formerly part of the Gas Operations Division testimony was reorganized with a portion moving to the IT and to Lean organizations. However, a new program called Work Management and Customer Delivery was created from the remaining Operations Performance organization, and that portion of the former organization remains in my testimony.

**Q. Please define and discuss the term Standard Labor Rate ("SLR") as it is used within the context of your testimony.**

A. The SLR is a cost allocation mechanism used by the Company to assign a direct labor dollar value to an individual work order. A direct labor dollar value is calculated starting with the direct labor hours spent completing a work order, then multiplying those hours by the SLR. The SLR represents an average payroll cost that considers regular time payroll costs, overtime payroll costs, and paid absence payroll costs. The specific dollar value of an SLR is reviewed periodically to update the rate for any changes in regular time, overtime, and paid absence payroll costs. For forecasts developed for future years, SLRs generally reflect current payroll costs levels with an annual forward-looking adjustment of 3% per year, which is consistent with the contractual labor agreement between the Company and its operating employees' union.

**Q. Please define and discuss the term Indirect Labor as it is used within the context of your testimony.**

A. Indirect Labor is a cost allocation mechanism used by the Company to assign payroll costs to a work order for periods of operating employee working time not directly attributed to a specific work order. Examples of these indirect working time costs include beginning of day or end of day administrative tasks, travel time between job sites, and meetings. Indirect Labor costs are allocated to specific work orders using indirect labor loading rates. These loading rates vary across different operating employee work groups and are reviewed periodically to manage any variances between actual indirect labor costs incurred and the amounts applied to work orders.

**Q. Please describe how vehicle costs are generally applied to a work order.**

A. Vehicle costs are allocated to work orders using vehicle loading rates, which are applied to the Direct Labor costs of a work order. Vehicle loading rates will vary between the various operating employee work groups, and these rates are reviewed periodically to manage any variances between actual vehicle costs and the amounts applied to work orders.

**Q. How has the Company projected its Gas Operations Division O&M expenses for the test year?**

A. The Company has identified the O&M expenses for the test year that are necessary to meet public safety and customer service requirements. The total amount of Gas Operations O&M expenses for which I am requesting recovery during this time period is $133,635,000 as shown on Exhibit A-86 (JPP-1), line 6, column (e). These forecasts reflect the Company's expectations for work activity as measured in units and/or orders, resource

requirements as measured by jobsite hours for each program, and the associated expense amount for each program.

**Q. Please explain the source of the 2023 actual and derivation of the projected test year O&M expenses for the Gas Operations expenses shown on Exhibit A-86 (JPP-1).**

A. The 2023 actual O&M expense amount of $111,299,000 as shown on Exhibit A-86 (JPP-1), line 6, column (b), for Gas Operations is derived from Consumers Energy's internal records. The projected test year expense levels for the Gas Operations Division programs were derived as explained below for each program. Unless otherwise noted, the program projections for the test year were calculated using a weighted average of the 2025 and 2026 forecast amounts, which reflect the Company's recent historical experience of monthly O&M expenses for individual programs.

The projected test year expense level of $133,635,000 will allow the Company to meet customer service, deliverability, and safety requirements.

**Q. Please explain the merit increase and inflation calculations that have been provided in Exhibit A-87 (JPP-2), page 2; Exhibit A-88 (JPP-3), page 2; and Exhibit A-89 (JPP-4), page 2.**

A. These specific pages of my exhibits present the anticipated amount of O&M expense increases that can be expected by applying either an inflation rate or a merit increase rate, or both, to historical O&M expense. Inflation was not used to determine the program funding in this case, however the following is an explanation of the exhibit.

Column (b), which is titled "Actual 12 Mos Ending Dec 31, 2023" shows the historical O&M expense. Column (c), entitled "Base O&M for Merit and Inflation 12 Mos Ending Dec 31, 2023" shows the amount of historical expense the Company believes

should be used as the base for calculating merit and inflation adjustments. The Company has excluded Operating Maintenance & Construction ("OM&C") employee direct labor and indirect labor from the base for merit and inflation calculations because the future increases in those costs reflect the current working agreement the Company has with its OM&C workforce. Columns (d), (f), and (h) show the merit and inflation amounts calculated for each respective period. Increases or decreases that have been projected using other methods, such as changes in OM&C labor rates applied to work orders or other workload changes, are included in column (i). Column (j) is the projected test year O&M and is the sum of columns (b), (d), (f), (h), and (i); column (j) is aligned with the Company's projected expenses for each sub-program for the test year, as shown on page 1 of my respective exhibits.

The inflation values in Exhibit A-87 (JPP-2), page 2; Exhibit A-88 (JPP-3), page 2; and Exhibit A-89 (JPP-4), page 2 were all set to 0.0% for 2024, 2025, and the test year. Therefore, column (i) represents the increase (or decrease) in O&M expenses when comparing the test year to 2023 Actuals. The projected increases from 2023 to the test year are explained for each sub-program as part of my direct testimony.

**Q. Are there any Employee Incentive Compensation Program ("EICP") O&M expenses included in your exhibits?**

A. No, there are not. The direct testimony and exhibits of Company witness Amy M. Conrad contain the Gas Operations Division EICP O&M expenses.

**Q. Are there any Injuries and Damages expenses included in your exhibits?**

A. No, there are not. The direct testimony and exhibits of Company witness Matthew J. Foster contain the Gas Operations Division Injuries and Damages expenses.

**Proposed Leak Detection and Repair Regulations**

**Q. Does the Company anticipate any new regulations from the Pipeline and Hazardous Materials Safety Administration ("PHMSA") during the test year?**

A. Yes. The Company anticipates that PHMSA will adopt proposed regulatory amendments that implement congressional mandates in the *Protecting the Infrastructure of Pipelines and Enhancing Safety Act of 2020* ("PIPES Act"). The objective of the PIPES Act is to reduce methane emissions from new and existing gas transmission pipelines, distribution pipelines, and underground natural gas storage facilities. PHMSA's proposed regulatory amendments are otherwise referred to as Leak Detection and Repair ("LDAR") rules.

Among the amendments for part 192 Regulated Gas Pipelines are:

- Strengthened leakage surveys, and patrolling requirements,
- Performance standards for advanced leak detection programs,
- Modified leak grading and repair criteria with mandatory repair timelines,
- Requirements for mitigation of emissions from blowdowns,
- Pressure relief device design, configuration, and maintenance requirements, and
- Clarified requirements for investigating failures.

Finally, PHMSA expanded reporting requirements for operators of all gas pipeline facilities within DOT's (Department of Transportation) authority.

More specifically, these mandated requirements will require the Company to perform the following tasks that will incur additional O&M expense:

- Increase the frequency of the periodic Leak Surveys the Company currently performs,
- Increase the frequency of Line Patrols the Company currently performs,

- Accelerate timeline for Leak Repairs,
- Perform Post Repair Inspection and any necessary remediation within the mandated period, and
- Conduct Environmental Change Surveys to investigate known leaks.

The Company expects the rule to be published by January 2025, with an anticipated effective date six months later. The Company anticipates that the LDAR rules will include a phase in period, with full compliance with these requirements expected in January 2028.

**Q. Please describe the PHMSA's LDAR requirements the Company is expecting to be required to comply with during the test year.**

A. PHMSA proposes to require operators to complete repairs of grade 2 leaks known to exist on or before July 2025, the Company's anticipated effective date of the rule, within one year from the date of publication of the final rule. The expected compliance date with this portion of the rule is January 2026. Also, PHMSA proposes to require a grade 3 leak known to exist on or before the effective date of the rule be repaired within three years from the date of publication of the final rule. The expected compliance date with this portion of the rule is January 2028. In addition, PHMSA proposes to require operators to complete repairs of any leak on a gas transmission line in a High Consequence Area (HCA), Class 3 or Class 4 location known to exist on or before the effective date of the rule within one year from the date of publication of the final rule. The expected compliance date with this portion of the rule is January 2026.

**Q. Please describe the Company plan to comply with the leak backlog requirements of the proposed rule.**

A. Based on the Company's understanding of the compliance timeline of the regulation, the Company will not request full compliance funding in this case for O&M expenses related

to the LDAR rule set forth in the Notice of Proposed Rulemaking and as modified from the Gas Pipeline Advisory Committee ("GPAC") LDAR meetings. However, based on the proposed known leak elimination requirements of the rule, considering the benefits to public safety, and the Company's desire to further reduce risk, the Company will ask for funding for this portion of the LDAR requirements. The Company plans to eliminate the backlog of known leaks on the system at an accelerated rate as part of the work plan, regardless of the timing of the LDAR rule publication. The Company plans to spend $1,300,000 to address the anticipated leak backlog on the system for the test year in the Leak Survey and Repair program section of my testimony. The Company realizes the final rule has not yet been published, and substantive changes could be made to the rule resulting in meaningful changes to the costs projected in this case. Therefore, the Company is requesting the Commission approve the ability to defer any test year O&M expense that occurs as a result of the requirements of the final rule that are above the requested funding in this case. It is important to note the regulation is expected to be published at or shortly after the filing of this case, therefore the Company expects to have additional data available during the discovery phase of this case.

**Operations, Maintenance, and Metering**

**Q. Please describe the O&M expenses related to the Operations, Maintenance, and Metering sub-programs shown on Exhibit A-87 (JPP-2).**

A. The Operations, Maintenance, and Metering sub-programs include the operation and maintenance of the Transmission and Distribution system. Major assets in these sub-programs include mains, services, pipelines, storage fields, meters, city gates, valves, and regulators. The sub-programs also include leak survey and repair, damage repair, odor

response, meter reading, meter services, right of way clearing, and staking. The Operations, Maintenance, and Metering sub-programs include several customer demand programs related to the front-line operations of the natural gas service and natural gas distribution areas of the Company. Gas Transmission employees focus on safely maintaining the Company's above and underground transmission system (pipelines, meters, regulators, city gates, and storage fields).

Gas Distribution employees primarily focus on safely maintaining the Company's underground facilities (gas mains and services), meter stands, and regulation facilities. Gas service employees focus on safely maintaining the Company's above ground facilities (such as meters and meter piping). Each sub-program is more fully described below.

**Distribution Cathodic Protection**

**Q. Please describe the O&M expenses related to the Distribution Cathodic Protection sub-program.**

A. This program is associated with regulatory-required corrosion control activities of the gas distribution system. Cathodic protection reduces the corrosion on steel main that could lead to natural gas leaks over time. The Company is projecting test year spending of $2,915,394 on Distribution Cathodic Protection.

**Q. Please provide a breakdown of the work being performed in the test year for the Distribution Cathodic Protection sub-program.**

A. This program includes O&M expenses for annual pipe-to-soil readings, bi-monthly rectifier and foreign bond readings, interference testing, diagnosis of sectors not meeting cathodic protection criteria, and repairs to downed sectors to meet code requirements. The Company currently has 49,447 test points read annually for pipe-to-soil readings, as well as an

additional 1,483 bi-monthly reads at rectifiers and designated bond points. The annual test point reads by Headquarters for this sub-program are summarized in the following table:

**Table 1**

| 2025 Annual Reads Per Headquarters | |
|---|---|
| **Work Headquarters** | **Annual Read at Designated Test Points Complete 100% of These Reads Impacts Year 2026** |
| Adrian | 429 |
| Alma | 945 |
| Bad Axe | 617 |
| Bay City | 1,996 |
| Cadillac | 94 |
| Flint | 4,910 |
| Greenville | 606 |
| Groveland | 2,715 |
| Hastings | 575 |
| Howell | 1,061 |
| Jackson | 1,686 |
| Kalamazoo | 3,375 |
| Lansing | 3,795 |
| Livonia | 6,258 |
| Macomb | 7,945 |
| Marshall | 224 |
| Midland | 1,277 |
| Owosso | 905 |
| Royal Oak | 6,957 |
| Saginaw | 3,077 |
| **Total** | 49,447 |

For the test year, the Company will have approximately 49,447 test points to read for pipe-to-soil readings. The Company's test points vary from year to year as it installs new plastic main, which changes the design of cathodic protection for that section of pipeline.

For the test year, the Company will have 1,438 bi-monthly reads at rectifiers and designated bond points. The overall number of reads has reduced as the Company installs remote monitoring units ("RMUs") that reduced the bi-monthly requirements during the months of January, May, July, September, and November.

The bi-monthly reads by Headquarters for this sub-program are summarized in the following table:

**Table 2**

| 2025 Bi-monthly Reads (Includes Rectifiers and Bond Points) | | | | | | | |
|---|---|---|---|---|---|---|---|
| **Work Headquarters** | **Jan** | **Mar** | **May** | **Jul** | **Sep** | **Nov** | **Total** |
| Adrian | 0 | 13 | 0 | 0 | 0 | 0 | |
| Alma | 7 | 41 | 7 | 7 | 7 | 7 | |
| Bad Axe | 0 | 14 | 0 | 0 | 0 | 0 | |
| Bay City | 2 | 41 | 2 | 2 | 2 | 2 | |
| Cadillac | 0 | 10 | 0 | 0 | 0 | 0 | |
| Flint | 2 | 87 | 2 | 2 | 2 | 2 | |
| Greenville | 0 | 15 | 0 | 0 | 0 | 0 | |
| Groveland | 6 | 79 | 6 | 6 | 6 | 6 | |
| Hastings | 2 | 27 | 2 | 2 | 2 | 2 | |
| Howell | 1 | 33 | 1 | 1 | 1 | 1 | |
| Jackson | 14 | 64 | 14 | 14 | 14 | 14 | |
| Kalamazoo | 15 | 164 | 15 | 15 | 15 | 15 | |
| Lansing | 9 | 88 | 9 | 9 | 9 | 9 | |
| Livonia | 5 | 68 | 5 | 5 | 5 | 5 | |
| Macomb | 5 | 38 | 5 | 5 | 5 | 5 | |
| Marshall | 3 | 16 | 3 | 3 | 3 | 3 | |
| Midland | 0 | 31 | 0 | 0 | 0 | 0 | |
| Owosso | 2 | 29 | 2 | 2 | 2 | 2 | |
| Royal Oak | 15 | 89 | 15 | 15 | 15 | 15 | |
| Saginaw | 0 | 51 | 0 | 0 | 0 | 0 | |
| **Total** | 88 | 998 | 88 | 88 | 88 | 88 | 1,438 |

In addition to the annual reads, the O&M expenses include dollars to complete three-year atmospheric above grade inspections at 2,103 locations and 120 bridge inspections in 2026. The atmospheric above grade and bridge inspection by Headquarters for this sub-program is summarized in the following table:

**Table 3**

| 2025 – 3-Year Inspections Including Contractor Bridge Inspections | | | |
|---|---|---|---|
| **Work Headquarters** | **Atmospheric Aboveground Corrosion Inspection (every 3 years) Impacts 2026** | **3-Year Bridge Inspections Impacts 2026** | **Total** |
| Adrian | 22 | 2 | 24 |
| Alma | 35 | 0 | 35 |
| Bad Axe | 35 | 0 | 35 |
| Bay City | 103 | 0 | 103 |
| Cadillac | 6 | 0 | 6 |
| Flint | 194 | 11 | 205 |
| Greenville | 25 | 2 | 27 |
| Groveland | 62 | 17 | 79 |
| Hastings | 30 | 0 | 30 |
| Howell | 47 | 9 | 56 |
| Jackson | 142 | 2 | 144 |
| Kalamazoo | 231 | 4 | 235 |
| Lansing | 204 | 9 | 213 |
| Livonia | 128 | 14 | 142 |
| Macomb | 263 | 18 | 281 |
| Marshall | 20 | 2 | 22 |
| Midland | 38 | 0 | 38 |
| Owosso | 61 | 4 | 65 |
| Royal Oak | 233 | 24 | 257 |
| Saginaw | 224 | 2 | 226 |
| **Total** | **2,103** | **120** | **2,223** |

For the test year, the Company will have approximately 31 bridge locations to complete repairs on, based upon its 2023 bridge inspection results.

The Company anticipates that approximately 2,500 sectors will not meet cathodic protection requirements within the given test year based upon historical trends.

Sectors will not meet criteria for a variety of reasons, including third-party damages to cathodic bond wires, foreign utility crossings that draw cathodic protection voltage away from steel gas mains, and anode/groundbed lifespan deterioration. This historical trend in this sub-program is summarized in the following table:

**Table 4**

| Historical Data<br>2023 and 2024 Downed Sectors | |
|---|---|
| **2023** | **2024 YTD September** |
| 2,217 downed sectors | 1,978 downed sectors |

In addition to the annual reads, inspections, and diagnostic work, the O&M expenses also include dollars to complete approximately 700 repairs in combinations of coating repair, above and below grade short removal, test wire repairs, rectifier repairs, groundbed repairs, and atmospheric corrosion repairs on service risers. These expenses are projected based on historical information and include the number of annual and bi-monthly survey reads that must be completed each year/month in compliance with regulatory standards.

The historical year costs and projected test year costs for this sub-program are summarized in the following table:

**Table 5**

| Distribution Cathodic Protection<br>Projection Breakdown by Activity Type | | |
|---|---|---|
| **Work Type** | **2023 Actual** | **2025-2026 Test year** |
| Distribution Cathodic Protection – Non-WBS | $220,837 | $252,107 |
| Cathodic Protection – Contractor; Material and Other Expenses | $505,839 | $577,463 |
| Cathodic Repairs | $198,640 | $226,767 |
| Sector Diagnosis | $254,433 | $290,460 |
| Annual Pipe to Soil Survey | $1,097,498 | $1,252,899 |
| Riser Wraps – Non-Leak Maintenance | $44,268 | $50,536 |
| Bi-Monthly Survey | $232,274 | $265,163 |
| **Total Program** | $2,553,789 | $2,915,394 |

**Q. What is the basis for determining the $2,915,394 of projected O&M expenses in the test year for this sub-program?**

A. Projected test year spending in this sub-program is primarily driven by annual reads, inspections, repairs, reduced contractor utilization, and diagnostic work. The historical and projected activity for Company crews in this sub-program is summarized below in the following table:

**Table 6**

| Distribution Cathodic Protection Units/Orders, Hours & Dollars | | | |
|---|---|---|---|
| **Year (Jan-Dec)** | **Units/Orders** | **Hours** | **Program Dollars** |
| 2016 | 31,705 | 24,616 | $2,377,667 |
| 2017 | 40,664 | 19,127 | $2,783,055 |
| 2018 | 44,794 | 20,222 | $3,762,986 |
| 2019 | 52,924 | 15,029 | $2,477,811 |
| 2020 | 43,146 | 15,720 | $3,190,166 |
| 2021 | 52,355 | 13,353 | $3,140,486 |
| 2022 | 35,514 | 13,451 | $2,677,564 |
| 2023 | 40,443 | 11,056 | $2,553,789 |
| 2024 Projected | 50,325 | 11,303 | $1,988,742 |
| 2025 Projected | 49,526 | 9,274 | $1,835,255 |
| 2025-2026 Test year | 49,874 | 9,474 | $2,915,394 |

The Company's projection for Distribution Cathodic Protection test year spending is based on a weighted average of the 2025 (3%) and 2026 (97%) forecast amounts, which reflects the Company's historical experience of program expense timing.

**Pipeline – Distribution**

**Q. Please describe the O&M expenses related to the Operations and Maintenance Pipeline – Distribution sub-program.**

A. The Operations and Maintenance Pipeline – Distribution sub-program includes multiple activities that ensure safe and reliable delivery of gas to customers' homes. For this sub-program, the Company is projecting test year spending of $11,512,760.

**Q. What work is undertaken as part of the Operations and Maintenance Pipeline – Distribution sub-program?**

A. This sub-program includes customer-requested work requiring alterations to existing gas mains and services, including new business branch services, meter and service relocations (where the entire service from the main to the meter is not installed or replaced) and replacing risers for installation of new meters. Where the entire service from main to meter is installed or is replaced, the costs become capital and are not included in this program. With respect to the condition of Company assets, the work activities include designated valve repairs, cross bore repairs, inside meter inspection, no-gas investigation and repair, non-leaking maintenance activities such as repairing or replacing lockwing valves to allow emergency shut-offs, replacing mushroomed plastic risers, replacing copper risers due to atmospheric corrosion, lowering main or service facilities if grade has changed, installing and pumping drips on the standard (low) pressure system thereby helping to alleviate water infiltration and freezing of service lines and meters, and property restoration costs. This sub-program also includes site checking activities to ensure customer locations are ready for work and improve efficiency and on-time delivery by avoiding unnecessary field trips by distribution crews. Site check activities additionally include confirming all jobsite

requirements have been met, such as underground facility staking, sewer lead locations, final grade established, and site readiness prior to the arrival of distribution construction crews. In addition, electric usage utility costs for the gas distribution regulation facilities and the inspections at the Huron Compressor Station are both included in this sub-program. The historical year costs and projected test year costs for this program are summarized in the following table:

**Table 7**

| Operation & Maintenance – Distribution Projection Breakdown by Activity Type | | |
|---|---|---|
| **Work Type** | **2023 Actual** | **2025-2026 Test year** |
| Material Condition Emergent | $781,582 | $1,008,223 |
| Material Condition | $3,630,493 | $4,683,256 |
| Huron Compressor Station | $116,506 | $150,290 |
| Main & Services Alterations | $1,858,802 | $2,397,813 |
| Property Restoration | $1,036,362 | $1,336,884 |
| Site Checks | $225,909 | $291,417 |
| Pre-fabrication Costs | $738,160 | $952,210 |
| Other, including Non-WBS, Utilities | $536,961 | $692,667 |
| **Total Program** | $8,924,773 | $11,512,760 |

**Q. What is the basis for determining the $11,512,760 of projected O&M expenses in the test year?**

A. Projected test year spending adjustments are driven by the following changes in the workplans:

- Adding the no-gas investigation and repair work,
- Increased number of non-leak maintenance (NLM) orders based on the rotation of area being surveyed and improved training to ensure all NLMs are identified,
- Alignment with customer-requested workload,

- Managing third-party contractor costs of performing this work, such as temporary traffic control and hydrovac usage.

The 2024 and 2025 projections anticipate increases to workload completion and increased labor rates for Distribution and Service employees.

Distribution and Service worker hourly standard labor rates are expected to be:

**Table 8**

| | Distribution | | | | Service | | | |
|---|---|---|---|---|---|---|---|---|
| | Standard Labor Rates | Indirect Labor Rates | Vehicle Rates | Total Rate | Standard Labor Rates | Indirect Labor Rates | Vehicle Rates | Total Rate |
| **2023** | $69.86 | $37.72 | $43.31 | $150.90 | $70.23 | $105.35 | $25.99 | $201.56 |
| **2024** | $73.41 | $39.64 | $33.77 | $146.82 | $73.80 | $98.15 | $22.14 | $194.09 |
| **2025** | $75.58 | $40.81 | $40.81 | $157.21 | $75.63 | $102.86 | $22.69 | $201.18 |
| **2026** | $78.47 | $42.37 | $42.37 | $163.22 | $78.52 | $106.79 | $23.56 | $208.86 |

This historical and projected activity in this sub-program is summarized in the following table:

**Table 9**

| Operations & Maintenance – Distribution Units/Orders, Hours & Dollars | | | |
|---|---|---|---|
| **Year (Jan-Dec)** | **Units/Orders** | **Hours** | **Dollars** |
| 2016 | 10,612 | 37,298 | $5,787,716 |
| 2017 | 9,415 | 40,679 | $6,878,971 |
| 2018 | 10,023 | 43,952 | $8,241,128 |
| 2019 | 10,722 | 40,430 | $7,998,681 |
| 2020 | 9,064 | 43,157 | $7,850,034 |
| 2021 | 13,755 | 59,207 | $11,721,014 |
| 2022 | 9,983 | 47,774 | $10,531,290 |
| 2023 | 9,370 | 40,741 | $8,924,773 |
| 2024 Projected | 17,132 | 45,017 | $10,814,580 |
| 2025 Projected | 14,708 | 41,450 | $9,066,529 |
| 2025-2026 Test year | 16,703 | 53,172 | $11,512,760 |

The Company's projection for the Operations and Maintenance Pipeline – Distribution sub-program test year spending is a weighted average of the 2025 (7%) and

2026 (93%) forecast amounts, which reflect the Company's historical experience of program expense timing.

**Pipeline – Transmission**

**Q. Please describe the O&M expenses related to the Operations and Maintenance Pipeline - Transmission sub-program.**

A. The Operations and Maintenance Pipeline - Transmission sub-program includes expenses related to performing:

(a) Code Inspections,

(b) Third-party oversight and staking per MISS DIG 811 Underground Facility Damage Prevention and Safety Public Act 174 ("Act 174") of 2013, ("MISS DIG 811"),

(c) Demand Maintenance,

(d) Preventive Maintenance & Operations,

(e) Restoration/Right-of-Way ("ROW"), and

(f) Miscellaneous Expenses.

This sub-program ensures public safety by maintaining the integrity of the Company's gas transmission pipeline system through inspection and repair of all critical assets to sustain proper operating conditions. Sub-program funding also includes necessary maintenance of valves sites, buildings, fencing, and security systems and structures. For this sub-program, the Company is projecting test year spending of $3,741,356.

**Q. Please provide a description of the work activities in the Operations and Maintenance Pipeline - Transmission sub-program.**

A. This sub-program includes the following work activity categories.

- Code Inspections include completing Michigan Gas Safety Standards ("MGSS") and Michigan Department of Environment, Great Lakes, and Energy ("EGLE") code inspections associated with pipeline valves, pipe, and

associated assets. This work is generally completed by Company employees and code inspection orders typically include labor and ancillary material costs. Examples of these inspections include vehicle and foot patrol of pipelines, leak survey, valve inspections, Pressure Limiting Device inspections, Remote Control Valve inspection, corrosion inspections, maintenance pigging, and inspection of gas quality equipment, including drip logs and separators that protect pressure regulation and customer metering equipment. One key example is line patrols where, based on class location, the Company patrols the system from one to four times per year to investigate for new dwellings, leaks, and third-party activity. As part of these line patrols, the Company takes appropriate actions to repair equipment and/or remediate in compliance with the MGSS. (MGSS code/standard/section 192.705, 192.706, 192.613, 192.935). This sub-program also includes MGSS required pipeline maintenance cleaning pig runs on five transmission lines that need to be completed annually. These pig runs are coordinated with the Company's Pipeline Integrity Program to avoid duplicate pig runs in the same calendar year. This work is included as part of the Company's Transmission Integrity Management Program.

- The Pipeline Preventative Maintenance and Operations portion of the sub-program involves proactive and necessary inspections that do not fall under code requirements but are necessary for maintaining safe, reliable, and predictable system operations for customers. Such inspections include: (a) instrument calibration; (b) launcher and receiver inspections; (c) vehicle safety inspections; (d) general safety inspections; (e) liquid drip collection; (f) housekeeping; and (g) site maintenance and other general functions.

- The Demand Maintenance portion of the sub-program accounts for labor and materials, to address pipeline assets that require repair due to performance during annual inspections, outages, or other activities. These activities typically include: (a) maintenance of valves, cathodic protection test stations, rectifiers, liquid collection equipment, pipeline markers, metering equipment, communication equipment, calibration equipment, pipe coating, sites, and facilities; (b) leak repairs; (c) ROW access maintenance; (d) third-party damage repairs; and (e) snow plowing.

- The Facilities Locating for Third Parties (MISS DIG 811) portion of the sub-program is primarily comprised of labor hours required to evaluate, locate, stake, and oversee third-party activities near transmission pipelines.

- Non-Work Breakdown Structure ("Non-WBS") portion of the sub-program includes labor, internal departmental chargebacks, contractors, and materials not directly associated with a specific work order. These costs include OM&C travel and meal charges, Company Laboratory labor for equipment calibration, storeroom stock and non-stock material issues, equipment rental charges, storage space rental, electric bills for rectifiers, and other site equipment.

- Contractor Materials, Credits and Other Expenses portion of the sub-program includes Contractor labor, credits, and materials for Code Inspection, Preventive Maintenance & Operations, Demand Maintenance, and Facilities Locating for Third Parties (MISS DIG 811) that are directly associated with a specific work order.

The historical year costs and projected test year costs for this sub-program are summarized in the following table:

**Table 10**

| Operation & Maintenance – Pipeline- Transmission Projection Breakdown by Activity Type | | |
|---|---|---|
| **Work Type** | **2023 Actual** | **2025-2026 Test year** |
| Non-WBS | $710,866 | $754,752 |
| Contractor; Materials, Credits and Other Expenses | $392,062 | $377,963 |
| Code Inspections | $871,321 | $782,592 |
| Preventive Maintenance & Operations | $385,434 | $365,210 |
| Demand Maintenance | $380,031 | $417,383 |
| Facilities Locating for Third Parties (PA 174) | $1,090,828 | $1,043,456 |
| **Total Program** | $3,830,542 | $3,741,356 |

**Q. What is the basis for determining the $3,741,356 of projected O&M expenses in the test year for this sub-program?**

A. The Company's projection for the Operations and Maintenance Pipeline – Transmission sub-program test year spending is a weighted average of the 2025 (10%) and 2026 (90%) forecast amounts, which reflect the Company's historical experience of program expense timing. As shown in the table above, projected spending in this sub-program is primarily driven by known hours for regulatory driven code inspections, preventative maintenance, and maintenance pigging activities. Demand maintenance (conditions requiring short-term response), and facility locating for third parties (MISS DIG 811), are projected based on historical trends and anticipated needs. The projected labor hour allocations for Code

Inspections are based on historical time to perform required inspections and maintenance to the assets on the transmission pipeline system.

The projected expenses associated with Facilities Locating for Third Parties (MISS DIG 811) activities are comprised of historical data and projected trends. Historically, ticket volumes have trended down due to a greater volume of tickets being processed in the office, and only actionable tickets being sent to the operational groups.

Based on the trend experienced in 2023 and the current economic growth, ticket volumes and hours are expected to be flat through 2026 (see below table).

**Table 11**

| Miss Digs 811 Tickets and Associated Hours | | |
|---|---|---|
| **Year** | **Orders** | **Hours** |
| 2016 | 12,538 | 6,119 |
| 2017 | 14,440 | 7,000 |
| 2018 | 18,412 | 8,327 |
| 2019 | 20,531 | 10,181 |
| 2020 | 20,150 | 10,274 |
| 2021 | 15,931 | 8,633 |
| 2022 | 9,562 | 7,801 |
| 2023 | 9,337 | 8,115 |
| Trend 2024 | 9,000 | 8,000 |
| Trend 2025 | 9,000 | 8,000 |
| Trend 2026 | 9,000 | 8,000 |

Gas Transmission worker hourly standard labor rates are expected to be:

**Table 12**

| Transmission | | | | |
|---|---|---|---|---|
| | **Standard Labor Rates** | **Indirect Labor Rates** | **Vehicle Rates** | **Total Rate** |
| 2023 | $69.18 | $24.90 | $36.67 | $130.75 |
| 2024 | $72.53 | $23.93 | $34.81 | $131.28 |
| 2025 | $76.37 | $26.73 | $32.08 | $135.17 |
| 2026 | $79.28 | $27.75 | $33.30 | $140.33 |

The historical and projected activity in this sub-program is summarized in the following table:

**Table 13**

| Operations–& Maintenance - Pipeline Hours & Dollars | | |
|---|---|---|
| **Year (Jan-Dec)** | **Hours** | **Dollars** |
| 2016 | 24,033 | $2,675,390 |
| 2017 | 21,865 | $2,131,709 |
| 2018 | 23,556 | $2,670,236 |
| 2019 | 26,639 | $3,121,709 |
| 2020 | 23,634 | $3,012,604 |
| 2021 | 20,676 | $3,198,861 |
| 2022 | 21,783 | $4,221,974 |
| 2023 | 17,879 | $3,830,542 |
| 2024 Projected | 14,253 | $3,456,218 |
| 2025 Projected | 14,212 | $3,017,218 |
| 2025-2026 Test year | 18,631 | $3,741,355 |

**Regulation Distribution**

**Q. Please describe the O&M expenses related to the Operations and Maintenance - Regulation Distribution sub-program.**

A. The Operations and Maintenance - Regulation Distribution sub-program is responsible for delivering safe and reliable gas service pressure to customers. For the test year, the Company is projecting spending $8,496,643 for this sub-program. This program consists of all code compliance requirements for regulation stations and odorant facilities statewide. This includes all required annual inspections, and maintenance and repairs of these facilities. The sub-program ensures gas delivery to customers with a detectible odor required for public safety. Inspection of critical designated valves that isolate sections of the distribution pipeline system during planned outages or emergencies is also included in this sub-program. This is critical for system operations and public safety. The Regulation

Distribution sub-program is responsible for the statewide inspection, maintenance, and repair of:

- 662 Distribution Regulation Stations,
- 1,660 1-inch and larger high-pressure regulation stands,
- 100 Odorant Injection Facilities, and
- 7,270 Designated Pipeline Valves.

The historical year costs and projected test year costs for this sub-program are summarized in the following table:

**Table 14**

| Operation & Maintenance – Regulation Distribution Projection Breakdown by Activity Type | | |
|---|---|---|
| | **2023 Actual** | **2025-2026 Test year** |
| Designated Valves | $1,409,923 | $1,420,059 |
| Regulation Inspection | $3,924,357 | $3,952,570 |
| Regulation Repairs | $2,425,685 | $2,443,123 |
| Vegetation Management | $676,030 | $680,891 |
| **Total Program** | **$8,435,995** | **$8,496,643** |

**Q. What is the basis for determining the $8,496,643 projected O&M expenses in the test year for this sub-program?**

A. To efficiently and safely operate the distribution pipeline system, the Company continues to invest in new regulation facilities (city gates and distribution regulator stations). These investments are sponsored by Company witness Michael P. Griffin. These new or upgraded facilities have additional equipment and technology installed that requires annual inspection and maintenance. Examples include Supervisory Control and Data Acquisition ("SCADA") communication components, transducers, catalytic heaters, gas pipeline filter separators, odorant pump injection systems, additional designated blow-down valves on

Transmission Operated as Distribution pipe ("TOD"), and poly valves as required on all new gas main installed.

The historical and projected activity in this sub-program is summarized in the following table:

**Table 15**

| Operations & Maintenance – Regulation Distribution Units/Orders, Hours & Dollars | | | |
|---|---|---|---|
| **Year (Jan-Dec)** | **Units/Orders** | **Hours** | **Dollars** |
| 2016 | 5,129 | 41,366 | $4,609,086 |
| 2017 | 5,009 | 38,058 | $4,330,964 |
| 2018 | 6,240 | 40,943 | $6,169,182 |
| 2019 | 7,672 | 40,350 | $5,909,548 |
| 2020 | 8,246 | 42,432 | $6,363,894 |
| 2021 | 13,651 | 43,728 | $7,662,838 |
| 2022 | 10,701 | 52,315 | $9,126,940 |
| 2023 | 10,641 | 47,443 | $8,435,995 |
| 2024 Projected | 12,118 | 45,774 | $8,078,355 |
| 2025 Projected | 12,785 | 44,291 | $8,048,289 |
| 2025-2026 Test year | 13,435 | 45,433 | $8,496,643 |

The projection for the test year is a weighted average of the forecasts for 2025 (9%) and 2026 (91%), which reflects the Company's recent historical experience with the timing of program expenses.

**Measurement and Regulation Transmission**

**Q. Please describe the O&M expenses related to the Operations and Maintenance - Measurement and Regulation Transmission sub-program.**

A. The Operations and Maintenance - Measurement and Regulation Transmission sub-program is primarily responsible for gas measurement, pressure control, and gas quality for the Company's transmission system, which feeds the distribution system as well. This work is driven by MGSS, EGLE, Department of Transportation, Federal Energy

Regulatory Commission ("FERC"), PHMSA, Occupational Safety and Health Administration, and Sarbanes Oxley ("SOX") controls. This includes third-party supplies and metering to meet SOX requirements as well as lost and unaccounted fuel custody requirements. This sub-program also includes expenses relating to the inspection and repair of data acquisition systems, metering, pressure control valves and regulators, overpressure protection, odorization, gas quality analyzers, and gas conditioners. These inspections can include piping, regulators, transducers, SCADA, valves, operators, emergency shut down devices, separators, heaters, meters, relief valves, and odorizers. Also included are monitoring and operating gas quality and analysis equipment such as chromatographs, which measure for water ($H_20$), hydrogen sulfide ($H_2S$), carbon dioxide ($CO_2$), oxygen ($O_2$), and testing for Polychlorinated Biphenyls (PCB). Other expenses include vehicles, maintenance equipment, utility bills, regulatory permits, and general cost to maintain city gate sites, buildings, fencing, and security. This sub-program ensures the safety and compliance of Company gas transmission and distribution pipeline systems through inspection and repair of all critical assets to meet federal, state, and local agencies' regulatory requirements.

**Q. Please provide a description of the work activities in the Operations and Maintenance - Measurement and Regulation Transmission sub-program.**

A. This sub-program includes the following work activity categories.

- The Demand Maintenance projected expense accounts for labor, material, and contractor supported activities to perform repairs on measurement and regulation assets. These repairs can arise from code inspections or failed equipment that requires immediate or scheduled actions. This activity covers all required emergent work relating to safety or system improvements to ensure the flow of gas and material readiness. Examples include driveway stone and repairs, filters for separators and liquid extraction, building repairs and permitting, painting, brush and tree removal, landscaping, fencing, lighting, RTU repairs, transducer and ultrasonic instrumentation, and required

investigations to respond to gas control alarms, including RTU device communication failures. The additional equipment added to the system results in the increased units.

- The Preventative Maintenance projected expense supports performing proactive and necessary inspections that do not fall under the code requirements but are necessary for maintaining safe, reliable, and predictable system operations. Such inspections include Remote Terminal Unit ("RTU") inspections, instrument calibration, liquid drip collections, pilot filter replacements, winter system operational checks, non-code valve inspections, general site inspections, pressure changes, heater maintenance, orifice plate inspections, painting, and grade work. Additionally, preventative maintenance includes labor hours and material costs to maintain site access and conditions including access drive and site stone, grass and weed spraying and mowing, and fence condition. These costs are forecasted based on the number of facility locations that require regular maintenance as well as condition-based needs.

- The Inspections projected expense primarily consists of Company employee labor hours, services, and necessary material costs. Labor hour projections are based on historical time to perform inspections, required maintenance, and standard work initiatives to meet code, manufacturer recommendations, deliverability, and reliability of gas systems. Inspection units increase as new equipment (gas filtration, liquid separation, gas analyzers, chromatographs, and regulation) is being added to the system. Also, regulation and other ancillary equipment has been added, such as filter-separators and multiple station outputs to meet customer demands. The Inspection activity levels satisfy safety and compliance regulatory requirements of our gas transmission and distribution pipeline systems through inspection and repair of all critical assets to meet regulatory requirements.

- The Non-WBS portion of the sub-program is comprised of labor, materials, and services not associated with a work order. These costs include (a) travel and meal charges, (b) Company laboratory labor for equipment calibration, (c) stock and non-stock material, (d) heater glycols, (e) valve grease, (f) equipment rental charges, (g) storage space rental, (h) purchase power, (i) SCADA cellular bills, (j) repair parts, (k) outside services, (l) contractors, (m) buildings, (n) testing in laboratory services, and (o) parts and materials to support system operations and code work. This portion of the sub-program also includes actions needed to comply with governmental agencies and local ordinances. Costs here are projected based on historical spend.

- Contractor Materials, Credits and Other Expenses portion of the sub-program includes contractor labor, credits, and materials for inspections, preventive maintenance and operations, demand maintenance, and third-party contracts which are directly associated with a specific work order.

The historical year costs and projected test year costs for this program are summarized in the following table:

**Table 16**

| Operation & Maintenance – Transmission Measurement & Regulation Projection Breakdown by Activity Type | | |
|---|---|---|
| **Work Type** | **2023 Actual** | **2025-2026 Test year** |
| Non-WBS | $27,634 | $206,363 |
| Contractor; Materials, Credits and Other Expenses | $632,804 | $655,373 |
| Demand Maintenance | $597,885 | $529,575 |
| Preventative Maintenance | $1,352,067 | $1,210,456 |
| Inspections | $649,098 | $580,010 |
| Third Party Contracts | $237,088 | $201,743 |
| **Total Program** | $3,496,577 | $3,383,519 |

**Q. What is the basis for determining the $3,383,519 of projected O&M expenses in the test year for this program?**

A. The test year amount of $3,383,519 is a weighted average of the 2025 (15%) and 2026 (85%) forecast amounts shown above. This reflects the Company's historical experience of program expense timing. Much of the projected expense in this sub-program is derived from the Company's estimated gas transmission field worker jobsite hours.

Each activity includes a forecasted number of units and associated expected average amount of time to complete each unit. The units multiplied by the time to complete, along with anticipated labor rates, account for much of the cost projection. In total, the Company projects jobsite labor hours to be 17,737 hours during the test year in this proceeding.

Gas Transmission worker hourly standard labor rates are expected to be:

**Table 17**

| Transmission | | | | |
|---|---|---|---|---|
| | **Standard Labor Rates** | **Indirect Labor Rates** | **Vehicle Rates** | **Total Rate** |
| 2023 | $69.18 | $24.90 | $36.67 | $130.75 |
| 2024 | $72.53 | $23.93 | $34.81 | $131.28 |
| 2025 | $76.37 | $26.73 | $32.08 | $135.17 |
| 2026 | $79.28 | $27.75 | $33.30 | $140.33 |

The historical and projected activity in this program is summarized in the following table:

**Table 18**

| Operations & Maintenance – Measurement & Regulation Transmission Hours & Dollars | | |
|---|---|---|
| **Year (Jan-Dec)** | **Hours** | **Dollars** |
| 2016 | 18,233 | $4,609,086 |
| 2017 | 20,497 | $3,461,000 |
| 2018 | 20,497 | $3,074,000 |
| 2019 | 20,722 | $3,005,000 |
| 2020 | 18,540 | $2,897,776 |
| 2021 | 17,795 | $3,188,919 |
| 2022 | 17,197 | $4,339,305 |
| 2023 | 20,394 | $3,496,577 |
| 2024 Projected | 17,936 | $3,433,865 |
| 2025 Projected | 17,737 | $3,258,089 |
| 2025-2026 Test year | 17,737 | $3,383,519 |

**Odor Response**

**Q. Please describe the O&M expenses related to the Odor Response sub-program.**

A. This sub-program provides for around-the-clock response to odor calls and other emergencies, including initial response to third-party damages. The Company has been achieving an average annual response time of 30 minutes or less, to ensure the safety of customers and the public.

The Commission monitors the Company performance on response times to ensure the safety of customers and the public. The program consists of Company employee labor costs inclusive of material and fleet costs.

This sub-program deals with initial response to odor calls from customers and the general public. Final resolution of the odor calls, if determined to be caused by leaking gas from Company facilities, may be an O&M repair or a capital asset replacement. The costs of this sub-program cover the O&M portion of the final resolutions. The O&M portion is based on a historical two-year analysis, which is reviewed every year (using a rolling two-year average). This portion/average will fluctuate based on whether the leaks found on gas services and mains are repaired or replaced.

The Odor Response sub-program consists of labor costs that are based on the Reasonable Expectancy to complete each work activity along with known labor rates for the personnel completing the activity. Activities such as the leak investigation standard (six-house check) implemented by the Company in 2018, provides for a more thorough leak investigation. The standard requires Company employees to check the house for which the leak was called in as well as a six-house check, including the buildings next to the reported address and the three buildings on the other side of the main (which are often across the street). They check for leak sources at the service riser/entrance of these buildings.

The historical year costs and projected test year costs for this sub-program are summarized in the following table:

**Table 19**

| Odor Response Projection Breakdown by Activity Type | | |
|---|---|---|
| **Work Type** | **2023 Actual** | **2025-2026 Test year** |
| Odor Response | $6,308,854 | $6,440,887 |
| **Total Program** | **$6,308,854** | **$6,440,887** |

**Q. What is the basis for determining the $6,440,887 of projected O&M expenses in the test year for this sub-program?**

A. The Company has projected the costs of the Odor Response sub-program based on expected workload associated with 42,222 O&M odor response orders.

Each odor response call is expected to require gas service worker jobsite time of 0.75 hours, or about 45 minutes. This expected time requirement is based on reviews during 2023 and 2024 of jobsite time per order completed.

The test year also reflects projected gas service worker hourly standard labor rates, indirect labor rates, and vehicle rates.

Gas Service worker hourly standard labor rates are expected to be:

**Table 20**

| Service | | | | |
|---|---|---|---|---|
| | **Standard Labor Rates** | **Indirect Labor Rates** | **Vehicle Rates** | **Total Rate** |
| 2023 | $70.23 | $105.35 | $25.99 | $201.56 |
| 2024 | $73.80 | $98.15 | $22.14 | $194.09 |
| 2025 | $75.63 | $102.86 | $22.69 | $201.18 |
| 2026 | $78.52 | $106.79 | $23.56 | $208.86 |

The historical and projected activity in this sub-program is summarized in the following table:

**Table 21**

| Odor Response Program O&M Units/Orders, Hours & Dollars | | | |
|---|---|---|---|
| **Year (Jan-Dec)** | **O&M Units/Orders** | **Jobsite Hours** | **Dollars** |
| 2016 | 78,719 | 51,429 | $6,339,803 |
| 2017 | 58,892 | 34,012 | $4,521,650 |
| 2018 | 54,743 | 35,587 | $5,265,338 |
| 2019 | 56,755 | 40,061 | $6,146,752 |
| 2020 | 51,500 | 36,442 | $5,506,217 |
| 2021 | 48,248 | 36,057 | $6,159,004 |
| 2022 | 44,729 | 34,770 | $6,445,000 |
| 2023 | 42,023 | 32,402 | $6,308,854 |
| 2024 Projected | 43,444 | 32,619 | $6,259,031 |
| 2025 Projected | 37,359 | 28,020 | $5,640,958 |
| 2025-2026 Test year | 42,000 | 31,020 | $6,440,887 |

The projection for the test year, is a weighted average of the 2025 (10%) and 2026 (90%) forecast amounts, which reflect the Company's historical experience of program expense timing.

**Leak Repair and Survey**

**Q. Please describe the O&M expenses related to the Leak Repair and Survey sub-program.**

A. The Leak Repair and Survey sub-program includes Company labor and contractor services for annual mobile and walking leak surveys, and classification of leaks on mains, services, and meter stands called in by customers or found during leak survey activity.

The sub-program also includes leak repairs to mains, services, and meter stands, including installation of leak repair fittings and clamps, tightening of fittings and clamps, partial service replacement, and rebuilds of meter installations. This work is on the Company's distribution system and helps to ensure public safety. This program includes the costs associated with contracts for maintenance of customer-owned fuel lines and will continue to include those costs as well, in compliance with regulations for master meters operators. In accordance with Mich Admin R 460.20335, the costs associated with central meters, otherwise referred to as master meter systems, run through this Leak Repair and Survey sub-program. These costs are offset by the owner of the master meter system as specified under Mich Admin R 460.20335(d)(4).

The historical year costs and projected test year costs for this sub-program are summarized in the following table:

**Table 22**

| Leak Repair and Survey Projection Breakdown by Activity Type | | |
|---|---|---|
| **Work Type** | **2023 Actual** | **2025-2026 Test year** |
| Leak Survey | $5,339,146 | $5,000,000 |
| Leak Classification | $1,573,968 | $1,884,986 |
| Leak Assessments | $517,381 | $619,616 |
| Leak Repairs – Meter Stands and Regs | $3,286,805 | $4,510,960 |
| Leak Repairs – Services | $1,553,816 | $2,132,528 |
| Leak Repair – Mains | $2,594,560 | $3,531,910 |
| **Total Program** | **$14,865,676** | **$17,680,000** |

**Q. What is the basis for determining the $17,680,000 of projected O&M expenses in the test year for this sub-program?**

A. The projected expense in this sub-program is primarily driven by:

- Leak survey requirements,
- Leaks found during leak survey,
- Current actionable leaks,
- Leaks requiring repair, and
- Reducing the known leak back log.

**Leak surveys** are compliance driven per MGSS 192.481, 192.557, 192.613, 192.705, 192.706, 192.721, 192.723, and 192.935, which require line patrol and leak survey frequency for mains, services, and customer-owned gas systems. The frequency of leak surveys is determined by the survey type:

- Scheduled leak surveys - Required on a quarterly, semiannual, annual, three-year, or five-year basis,
- Non-scheduled leak surveys - Required on an as-needed basis,
- Contracted Customer-Owned Gas System Leak Surveys - Varies per contract,

- Discretionary leak surveys - Performed on an as-needed basis.

The Leak Surveys expense for the test year is forecasted to be higher than the previous two years with approximately 400,000 units and 10,000 miles of main. This is based on the code-required schedule and frequency of the gas facilities to be surveyed. The historical and projected **Number of Leaks found during Leak Survey** in this sub-program is summarized in Table 23. The 2024 Projected leaks in the table are based on actuals and a forecasted data.

**Table 23**

| Leaks Found During Survey | | | |
|---|---|---|---|
| **Year (Jan-Dec)** | **Above Grade** | **Below Grade** | **Total** |
| 2017 | 5,220 | 1,555 | 6,775 |
| 2018 | 7,931 | 1,715 | 9,646 |
| 2019 | 18,393 | 2,697 | 21,090 |
| 2020 | 9,842 | 1,589 | 11,431 |
| 2021 | 12,009 | 1,577 | 13,586 |
| 2022 | 9,714 | 1,516 | 11,230 |
| 2023 | 9,151 | 343 | 9,494 |
| 2024 Projected | 19,478 | 850 | 20,328 |

The increase in leaks found, per Table 23, drives the increased required leak repairs. The historical and projected Leak Survey Units, which represents the number of services, in this sub-program is summarized in Table 25. As shown in Table 25, the 2024 projected survey units are 166,433 units higher than 2023 due to the five-year survey schedule. This increased number of surveys is the main contributor to the increase in the number of leaks found for 2024.

**Leak Repair Scheduling** is required per code by MGSS 192.703, 192.709, 192.711, and Michigan Admin Code R. 460.20318 - 460.20318 - Gas leak investigation;

establishment of service; Michigan Admin Code R. 460.20327 - Section R. 460.20327 - Distribution system; leakage surveys and procedures. Each leak must have a complete leak analysis completed to determine the appropriate leak classification for repair scheduling. As a result of the new leak-found trend, and an initiative to reduce the overall leak backlog, leak repair units are forecasted to be higher than average. Forecasts are based on:

(1) Code requirements regarding leak classifications and repairs on active leaks,

(2) Code requirements on leak survey frequency,

(3) Resource availability, and

(4) Historical averages.

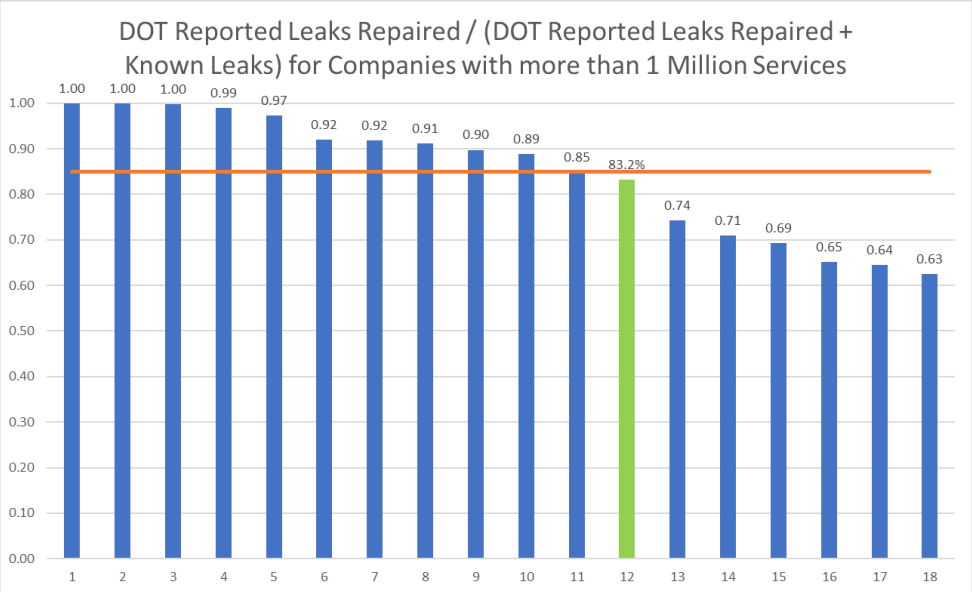
The historical and projected **Leak Repair Units** in this sub-program are summarized in Table 25. The historical and forecasted **Leak Classification** units are shown in Table 25.

The graph below depicts a comparison of natural gas utilities with more than one million customers with vintage main and is based on leaks repaired per leaks repaired and actionable leaks at year end (see the below formula).

$$\% = \frac{Leaks\ repaired}{Leaks\ repaired + Actionable\ Leaks}$$

Consumers Energy is depicted in green, and was at 83% as of year-end 2023, which is just below industry average of 85%. Based on benchmarked data, shown in Figure 1 below, the Company is seeking to position itself in the top of the first quartile, which drives improved system integrity and public safety.

**Figure 1**




The **leak repairs planned** for 2025 and 2026 will ensure the Company maintains a safe and reliable natural gas system by permanently repairing leaks. and working to eliminate our current leak backlog. Doing so, the Company can enhance public safety, increase the integrity of the natural gas system, reduce methane emissions, and lower long-term costs. With this plan, the Company will eliminate Grade 2 leaks by January 2026 and continue to reduce Grade 3 leaks through the test year. The NGDP will address long-term system integrity.

The projection for Company labor and vehicle costs are primarily based on the projected hours for each year. Increases in labor and vehicle costs from 2023 to the test year also reflect projected gas distribution worker hourly standard labor rates, indirect labor rates, and vehicle rates.

Gas Distribution worker hourly standard labor rates are expected to be:

**Table 24**

| Distribution ($/hr) | | | | |
|---|---|---|---|---|
| | **Standard Labor Rates** | **Indirect Labor Rates** | **Vehicle Rates** | **Total Rate** |
| 2023 | $69.86 | $37.72 | $43.31 | $150.90 |
| 2024 | $73.41 | $39.64 | $33.77 | $146.82 |
| 2025 | $75.58 | $40.81 | $40.81 | $157.21 |
| 2026 | $78.47 | $42.37 | $42.37 | $163.22 |

The historical and projected activity in this program is summarized in the following table:

**Table 25**

| Leak Repair and Survey Units/Orders, Hours & Dollars | | | | | |
|---|---|---|---|---|---|
| **Year (Jan-Dec)** | **Survey Units** | **Classification Units** | **Repair Units** | **Jobsite Hours** | **Dollars** |
| 2016 | 462,334 | 18,734 | 15,814 | 96,196 | $13,510,903 |
| 2017 | 556,249 | 13,079 | 13,815 | 67,091 | $10,908,621 |
| 2018 | 457,641 | 12,650 | 18,556 | 83,858 | $16,087,691 |
| 2019 | 480,394 | 13,374 | 21,970 | 98,567 | $20,232,711 |
| 2020 | 415,305 | 12,923 | 23,649 | 110,011 | $19,802,868 |
| 2021 | 491,858 | 7,438 | 18,612 | 97,692 | $21,786,507 |
| 2022 | 352,437 | 4,695 | 16,537 | 83,987 | $18,941,796 |
| 2023 | 368,287 | 3,981 | 14,132 | 60,650 | $14,865,676 |
| 2024 Projected | 534,720 | 5,566 | 21,402 | 64,244 | $16,714,729 |
| 2025 Projected | 350,968 | 5,095 | 21,331 | 64,061 | $16,760,000 |
| 2025-2026 Test year | 400,000 | 5,095 | 21,594 | 66,719 | $17,680,000 |

The projection for the test year is a weighted average of the 2025 (5%) and 2026 (95%) forecast amounts, which reflect the Company's historical experience of program expense timing.

**Q. Please describe the LDAR Rule impacts to this program.**

A. As talked about previously in my testimony, the Company plans to reduce the known leaks on the system, at an accelerated rate, as part of planned work, regardless of the timing of

the rule. The Company has included $1,300,000 is this program, which was allocated among the three Leak Repair work types in Table 2~~2~~1.

**Q. Please describe Advanced Methane Detection.**

A. In 2024, the Company conducted leak surveys with handheld instrumentation through foot patrol of gas service lines and infrastructure. Advanced Methane Detection uses higher sensitivity instrumentation to detect smaller amounts of gas release than traditional tools. During the test year, the Company plans to use a Grid based approach combined with Advanced Methane Detection to perform leak survey on a portion the Company's natural gas system. Advanced Methane Detection is further explained in Company witness Kristine A. Pascarello's testimony.

**Damage Repair**

**Q. Please describe the O&M expenses related to the Operations & Maintenance - Damage Repair sub-program.**

A. The Operations & Maintenance - Damage Repair sub-program involves repairing natural gas mains, services, and meter installations from third-party damages (such as excavators, other utilities, municipalities, and homeowners). These expenses are necessary to ensure public safety, and to bring the system back into service in a timely manner. Consumers Energy's operating employees assess the site, mitigate the gas leak caused by the damage, and make necessary repairs to the system. In addition, the program is the recipient of credits from billing (less write-offs) from these third parties. These credits have shown variability year over year for several reasons, such as volume of damages, third-party response (willingness or ability to pay), and market and economic conditions.

The historical year costs and projected test year costs for this sub-program are summarized in the following table:

**Table 26**

| Operation & Maintenance – Damage Repair Projection Breakdown by Activity Type | | |
|---|---|---|
| **Work Type** | **2023 Actual** | **2025-2026 Test year** |
| Service/Meter Stand Repair | $2,265,200 | $2,161,752 |
| Main Repair | $512,158 | $488,768 |
| Damage Assessment | $199,067 | $189,976 |
| Credits | ($1,561,893) | ($1,459,000) |
| **Total Program** | **$1,414,532** | $1,381,496 |

**Q. What is the basis for determining the $1,381,496 of projected test year O&M expenses for this sub-program?**

A. Spending in this sub-program is primarily driven by the number of damages recorded on the system. Projected costs consider historical volume and Company efforts to reduce damages to the gas system. The Company maintains a Public Safety Outreach ("PSO") function, using damage prevention liaisons, that seek to work with third parties through various channels to provide awareness of the gas system, and to prevent damages. Through PSO efforts, damage repairs are projected to be lower in 2025 and 2026. These efforts are meant to reduce costs for the damage repair portion of this program. Offsetting these cost reductions is a reduced level of damage credits being collected from or paid by third parties. A common reason for not billing a third party for damage is that the damaging party is unknown, such as when gas damage occurs, and the party leaves the scene prior to the Company arriving.

Gas distribution worker hourly standard labor rates are expected to be:

**Table 27**

| Distribution ($/hr) | | | | |
|---|---|---|---|---|
| | **Standard Labor Rates** | **Indirect Labor Rates** | **Vehicle Rates** | **Total Rate** |
| 2023 | $69.86 | $37.72 | $43.31 | $150.90 |
| 2024 | $73.41 | $39.64 | $33.77 | $146.82 |
| 2025 | $75.58 | $40.81 | $40.81 | $157.21 |
| 2026 | $78.47 | $42.37 | $42.37 | $163.22 |

This historical and projected activity in this sub-program is summarized in the following table:

**Table 28**

| Operations & Maintenance – Damage Repair | | |
|---|---|---|
| **Hours & Dollars** | | |
| **Year (Jan-Dec)** | **Hours** | **Dollars** |
| 2016 | 17,486 | $1,209,306 |
| 2017 | 17,497 | $624,348 |
| 2018 | 18,685 | $683,225 |
| 2019 | 18,471 | $1,102,498 |
| 2020 | 23,753 | $2,550,320 |
| 2021 | 19,644 | $1,379,759 |
| 2022 | 23,854 | $1,574,894 |
| 2023 | 18,402 | $1,414,532 |
| 2024 Projected | 17,615 | $1,448,021 |
| 2025 Projected | 15,898 | $1,255,351 |
| 2025-2026 Test year | 16,298 | $1,381,496 |

The test year projection is a weighted average of the 2025 (18%) and 2026 (82%) forecast amounts, which reflect the Company's historical experience of program expense timing.

**Staking & Locating**

**Q. Please describe the O&M expenses related to the Staking & Locating sub-program.**

A. The Staking & Locating sub-program involves Company labor and contractor services for the staking and locating of the Company's gas distribution pipeline facilities in accordance with Act 174 of 2013, MISS DIG 811 Underground Facility Damage Prevention and Safety Act, a key component of securing public and employee safety. Work is typically performed by a contracted outside service vendor on a multi-year contract with the Company.

**Q. Please discuss the work activities in the Staking and Locating Sub-Program.**

A. The Staking and Locating sub-program includes the following work activity categories:

- Outside Services – Staking and Locating: contractor costs are included for staking and locating activities that are performed under the shared resource model and advanced locating for abnormal operating conditions.

- Outside Services - Dedicated Contractor: contractor costs are included in the test year projection for staking and locating activities that will be performed under the Dedicated Contractor staking program.

- Company Labor: volumes and hours are included in the test year projection for Company labor to support standby inspections, and abnormal operating condition efforts. Included are the projected increases in labor and vehicle costs from 2023 to the test year for gas distribution worker hourly standard labor rates, indirect labor rates, and vehicle rates. The projection for Company labor and vehicle costs are primarily based on the projected hours for each year.

- Licenses, Permits & Fees: This includes the fees that Consumers Energy pays to the state MISS DIG 811 system as part of Act 174.

**Q. Please provide a breakdown of the Staking and Locating sub-program expense.**

A. The Staking & Locating sub-program expenses for 2023 and the test year expenses are identified in the table below:

**Table 29**

| Staking and Locating Sub-program Projection Breakdown by Activity Type | | |
|---|---|---|
| **Work Type** | **2023 Actual** | **2025-2026 Test year** |
| Outside Services - Staking and Locating (Shared) | $7,865,196 | $0 |
| Outside Services - Staking and Locating (Dedicated Oakland and Kent) | $2,766,691 | $6,703,509 |
| Outside Services - Staking and Locating (Dedicated remainder of service territory) | $0 | $15,112,608 |
| Company Labor | $1,401,778 | $1,802,959 |
| Licenses, Permits & Fees | $373,380 | $838,409 |
| **Total Program** | **$12,407,045** | **$24,457,485** |

**Q. What is the basis for determining the $24,457,485 of projected O&M expenses for this sub-program?**

A. Spending in this sub-program is primarily driven by staking request volume (units) and the cost of staking contractors. Table 32 shows the change in staking volumes realized year over year. The primary drivers for this increase include:

(a) Increase of $1,712,991 based on anticipated contractor volume increases of 66,379,

(b) Increase of $401,181 based on Company labor standard labor rate change and increased hours,

(c) Increase in MISS DIG 811 membership fees of $465,029, and

(d) Increase of $9,470,757 based on dedicated model expansion and contractor rate increases.

- The 2024 expansion of Oakland County from 67% to 100% of the dedicated staking ticket volumes, and the 2024 addition of Kent County under the dedicate model accounts for $2,179,247 of the increase.

- The 2025 expansion of the dedicated model to the remainder of the Company's Gas Service Territory, based on performance and the staking Request for Proposal (RFP) results, accounts for $7,291,510 of the increase. The Company is mitigating a higher increase by expanding its Dedicated Contractor approach, which is available at a lower unit cost

than continued use of the Shared Contractor approach and also provides numerous other benefits to customers described in more detail below.

Historical and forecasted expenses for the Staking sub-program are provided in the table below.

**Table 30**

| O & M – Staking & Locating Total Program | |
|---|---|
| **Year (Jan-Dec)** | **Dollars** |
| 2016 | $5,145,070 |
| 2017 | $5,828,563 |
| 2018 | $6,754,042 |
| 2019 | $8,200,186 |
| 2020 | $7,306,455 |
| 2021 | $10,982,945 |
| 2022 | $10,309,238 |
| 2023 | $12,407,527 |
| 2024 Projected | $15,213,591 |
| 2025 Projected | $22,653,823 |
| 2025-2026 Test year | $24,457,485 |

The test year expense projection is based on a weighted average of the 2025 (12%) and 2026 (88%) forecast amounts, which reflect the Company's historical experience of program expense timing.

**Q. Please describe the test year cost forecast for volume and unit cost.**

A. An anticipated unit cost increase is included in the test year projection for contractor services and with the requirement for enhanced capability to manage increased demand in performance and increasing labor costs.

The staking completed by an outside contracted vendor is billed based on contractual unit costs. An anticipated volume increase of 7.0% is included in the test year projection relative to 2024 contractor services. This is in alignment with the trend of the

historical data and staking forecasts for the state of Michigan. The anticipated contractor unit cost and staking volume increases is shown in the following table.

**Table 31**

| Contractor Stake & Locate Services | | |
|---|---|---|
| | **Base Unit cost ($/unit)** | **Base Unit Forecast (units)** |
| 2022 | $21.83 | 407,551 |
| 2023 | $26.71 | 412,008 |
| 2024 Projected | $30.49 | 437,004 |
| 2025 Projected | $44.66 | 450,823 |
| 2026 Projected | $45.67 | 482,380 |

The Statewide MISS DIG 811 Annual Ticket Requests table below shows the change in staking volumes realized year over year.

MISS DIG 811 data (www.missdig811.org/about/who-we-are/about-miss-dig.html) shows a continuous growth in staking and locating ticket requests for the entire State of Michigan, except for a small decline in 2020, which appears to be a temporary result of COVID-19 pandemic business impacts.

The following is the historic and projected Statewide MISS DIG 811 annual ticket requests:

**Table 32**

| Statewide MISS DIG 811 Annual Ticket Requests | | |
|---|---|---|
| **Year** | **Annual Ticket Requests** | **% Change From Prior Year** |
| 2016 | 814,303 | |
| 2017 | 872,896 | 7.2% |
| 2018 | 923,993 | 5.8% |
| 2019 | 1,015,753 | 9.9% |
| 2020 | 994,573 | -2.1% |
| 2021 | 1,088,030 | 9.4% |

| | | |
|---|---|---|
| 2022 | 1,093,021 | 1.0% |
| 2023 | 1,202,992 | 10.1% |
| 2024 Forecast | 1,323,291 | 10.0% |
| 2025 Forecast | 1,415,921 | 7% Assumed |

**Q. Please describes the Company's concerns with the increase in staking ticket volumes and proposed recommendation.**

A. The Company has estimated staking tickets for the test year based on the best information available at this time. With staking requests increasing due to fiber optic and other infrastructure work, the actual staking demand the Company experiences in 2026 could be above the company's staking volume forecast. While the Company attempts to forecast staking volumes with a high degree of accuracy, the largest factors influencing expenditures in these programs are externally driven. As a result, the Company requests it be allowed to defer for refund or recovery any O&M expenses for this program, below or above amounts included in rates for the test year. The request would avoid a potential budgetary impact on important programs in order to cover the required staking volume costs. It would also prevent customers from paying for costs that were not incurred if staking volumes are below forecasted levels.

**Q. Please describe the change in the Company's standard labor rate and volume increase.**

A. The projection for Company labor is primarily based on the projected hours for each year. Increases in labor also reflect projected gas distribution worker hourly standard labor rates. The table below shows historic and projected volumes and hours for Company crews.

**Table 33**

| OM&C Labor Breakdown – Advanced Locating & Inspections | | |
|---|---|---|
| **Year (Jan-Dec)** | **Units/Orders** | **Hours** |
| 2017 | 2,771 | 7,262 |
| 2018 | 2,988 | 7,281 |
| 2019 | 10,390 | 13,739 |
| 2020 | 2,366 | 10,933 |
| 2021 | 11,168 | 14,877 |
| 2022 | 2,298 | 8,962 |
| 2023 | 2,692 | 9,033 |
| 2024 Projected | 3,436 | 9,197 |
| 2025 Projected | 3,453 | 10,704 |
| 2025-2026 Test year | 3,606 | 11,180 |

Gas distribution worker hourly standard labor rates are expected to be:

**Table 34**

| Distribution ($/hr) | | | | |
|---|---|---|---|---|
| | **Standard Labor Rates** | **Indirect Labor Rates** | **Vehicle Rates** | **Total Rate** |
| 2023 | $69.86 | $37.72 | $43.31 | $150.90 |
| 2024 | $73.41 | $39.64 | $33.77 | $146.82 |
| 2025 | $75.58 | $40.81 | $40.81 | $157.21 |
| 2026 | $78.47 | $42.37 | $42.37 | $163.22 |

**Q. Why did the Company initially implement the Dedicated Contractor staking strategy?**

A. The Company's Dedicated Contractor staking strategy is to hire a contractor that is dedicated to staking only the Company's gas and electric assets. This was originally implemented in a limited portion of the Company's gas service territory because changes in the program were necessary to improve timeliness and accuracy of staking for public safety, especially given the continued ticket volume. Consumers Energy and the State of Michigan are in the fourth quartile for third-party gas distribution damages per

1,000 tickets. When accuracy and timeliness of staking are off target, this creates negative behaviors with third-party excavators, resulting in unsafe digging practices. A critical step in ensuring safe digging practices is having excellence in stake-and-locate timeliness and accuracy.

With a Dedicated Contractor staking strategy, the Company is looking to achieve the following key pillars in support of safe digging and the excavating community.

- The first key objective is *timeliness*. Through the dedicated workforce, the Company will see improved timeliness compared to historical performance to support the excavating community. This will be achieved by having a single utility focus for ticket management. This model improves the ability to manage ticket volume fluctuations throughout the year due to not having the risk of completing all other commitments on the ticket in the shared resource model.

- Another key objective is *quality*, with improved staking accuracy performance compared to recent historical data. This is expected to be achieved as stakers need only focus on one utility type, compared to the shared resource model, where stakers are responsible for all assets (electric, gas, communications, water). This will lead to increased staking proficiency.

- The last key objective is *improved excavator communications* on projects. Improved communications with the excavating community will be enabled by use of enhanced positive response, which provides additional information and pictures to the ticket initiator, and an additional payment type for 180-day project tickets to assist in mitigating the risk of rushing.

**Q. Please describe the test year costs for the Dedicated Contractor asset locating program.**

A. In the interest of public safety, damage prevention, and in compliance with a facility owner's obligation under Act 174, the act of placing marks to indicate approximate facility location in response to a MISS DIG 811 ticket requested in advance of excavation activity, an anticipated increase in volume and costs are included in the test year projection for gas-only locating. This includes resources to locate *only* gas facilities for Consumers Energy compared to the existing method of vendors locating several other additional

external facilities. Additionally, based on the existing benefits realized and lower comparative costs to the Shared Contractor resources, the Company plans to expand the program in 2025 to include all of the Company's statewide gas service territory.

**Q. Please describe the Company's plan to expand the Dedicated Contractor staking program.**

A. Based on existing benefit realization for the Dedicated Contractor staking program, the Company plans to expand the program to continue to improve public safety, reduce damages, mitigate communication risks with excavators, improve quality, and comply with timeliness requirement within Public Act 174. Beginning February 21, 2023, the Dedicated Contractor staking program covered two-thirds of Oakland County, which is 20% of the total staking tickets. The plan for 2024 has the Dedicated Contractor staking program covering 31% of the total staking tickets. In 2025, the Company plans to expand the Dedicated Contractor staking Program to include the Company's entire statewide gas service territory and cover up to 100% of the total staking ticket volume.

**Q. Please explain why the company accelerated the implementation of the Dedicated Contractor staking model to up to 100% of the total ticket volume in 2025.**

A. The staking contract with the contractor that the Company uses for its Shared Contractor approach expires in the first quarter 2025. In anticipation, the Company sent out a request for proposal in the third quarter of 2024 for staking services for the Company's remaining gas service territory that at the time was under the Shared Contractor resource model. The request included options for both shared and dedicated services. The bids yielded an average unit cost for the Dedicated Contractor resource model that was below the average unit cost of the Shared Contractor staking model. Based on the lower unit cost, the realized

timeliness, and quality improvement from the Dedicated Contractor resource model, the Company plans to pursue the lower cost Dedicated Contractor option and implement a statewide Dedicate Contractor staking approach for its gas service territory for up to 100% of the total staking ticket volume.

**Q. Please describe the benefits the Company has seen since implementing the Dedicated Contractor staking program.**

A. The Company has seen benefits to overall accuracy, timeliness, and excavator communications on projects since the implementation in February 2023.

In 2023, with the Dedicated Contractor resource model in place, two-thirds of Oakland County (compared to the Shared Contractor resources model in 2022) yielded the following results:

- Accuracy related to at-fault damage reduction improved by 87.3%.
- Field timeliness for the Dedicated Contractor model averaged 98.7% compared to 97.3% for the Shared Contractor resource model in 2023.

For 2024, year-to-date month ending September, the Dedicated Contractor model in place for Oakland and Kent County's compared to the Shared Contractor resources model yielded the following results:

- Accuracy related to at-fault damage reduction improved by 78.6% from 2022.
- Field timeliness for the Dedicated Contractor model averaged 99.5% (including 24 hour re-transmits) compared to 95.2% for the Shared Contractor resource model in 2024.

These results are anticipated to continue due to improvement in staking and locating performance. Additionally, excavator communication on projects has improved through enhanced positive response, which provides an overview of staking and associated pictures to the ticket requester.

**Q. Please describe the cost difference between the Shared Contractor resource model and Dedicated Contractor resource model after the RFP.**

A. The RFP bids were evaluated using actual 2024 ticket type data with redline and performance incentive adjustments made to provide an accurate comparison between the Shared Contractor resource model and Dedicated Contractor resource model bids. The analysis shows the Dedicated Contractor model is on average $10.90 less on a per unit basis when compared to the Shared Contractor model. Continuing with the Shared Contractor model, and not transitioning to the Dedicated Contractor resource model, would increase program cost by $3,667,000 for the Company's remaining gas service territory in the test year.

**Q. Has the Company added communication audits to assist in validating appropriate positive response code utilization as a result of the MPSC Safety Staff's recommendations in the Company's previous gas rate case?**

A. Yes. The Company is enhancing communication audits executed by the Company's Damage Prevention Field Liaisons as well as updating timeliness reporting to include county level data in addition to statewide, to assist in identifying incorrect positive response code utilization.

**Q. What other activities does the Company perform to reduce dig-in damages besides stake and locate?**

A. In addition to the stake and locate program, the Company has a robust damage prevention program that includes damage prevention and public safety liaisons, and public awareness activities.

Damage prevention and public safety liaisons focus on proactive support for the excavating community, including but not limited to training, troubleshooting locating needs, and communications and issues management for all involved stakeholders. The liaisons also play a critical role in the Company's damage investigation program, repeat damager program, and no-call program, where the liaisons follow up on damages in which MISS DIG 811 was not called. Additionally, they perform quality assurance audits on the Company's staking contractors for accuracy in locates. The Company has eight public safety liaisons, with the most recent being a dedicated individual for the gas transmission system due to an increasing number of near misses on the transmission pipelines. The Company has implemented the Irth Solutions UtiliSphere solution as a critical part of the damage prevention 811 ticket management. It enables standardization for field processes and supporting data. It can prioritize tickets and field activities, which help to mitigate the highest risks.

**Customer Requested Services**

**Q. Please describe the O&M expenses related to the Operations & Maintenance – Customer Requested Services sub-program.**

A. This sub-program includes the following work activity categories:

- Customer and Company Requested Service activities include Company labor and contractor services for meter and meter stand work, and appliance re-lights after interruptions. Interruptions may be customer driven or related to Company work such as gas facility replacement projects. This category also includes gas meter investigations associated with operational and billing issues.

- Charts and Inspection activities include gas meter inspections and battery exchanges. This work is associated with the metering equipment for commercial and industrial customers. The charts and inspection requirement helps to ensure accuracy in gas flow and utilization.

- Gas Meter Routine activity includes scheduled and companion gas meter exchanges. This work fulfills the Company's Routine Meter Exchange Program. Every year, the Company removes (exchanges) a sample of meters (specific years and types) and tests them for billing accuracy to fulfill MPSC requirements. The number of exchanges required annually is determined according to the testing procedures currently in effect, which specifies how meters are grouped and how many meters of each lot are to be removed and tested annually.

- Meter Work activities including gas turn-ons, turn-offs, investigative tests, as well as setting and removing meters. This work is both emergent and customer committed and is planned based on historical levels; transportation customer meter reads are part of this activity. Also, Smart Energy Advanced Metering Infrastructure ("AMI")/Automated Meter Reading ("AMR") activities were added to the program in 2017 with the implementation of the Gas AMI/AMR project. All activities associated with the gas communication modules are included in this activity, which are investigations, removals, exchanges, and installations of gas communication modules. Deployment has completed, and work has shifted to troubleshooting communication issues with the AMI/AMR meters.

- Non-WBS portion of the sub-program includes labor, internal departmental chargebacks, contractors, and materials not directly associated with a specific work order.

- Contractor Materials, Credits and Other Expenses portion of the sub-program includes Contractor labor, credits, and materials for work associated with the activities below.

The historical year costs and projected test year costs for this sub-program are summarized in the following table:

**Table 35**

| Operations & Maintenance – Customer Requested Services<br>Projection Breakdown by Activity Type | | |
|---|---|---|
| **Work Type** | **2023 Actual** | **2025-2026 Test year** |
| Non-WBS | $908,747 | $1,083,169 |
| Contractor; Materials, Credits and Other Expenses | $339,204 | $553,924 |
| Cust Req Services | $4,262,969 | $4,501,755 |
| Charts & Inspections | $2,061,833 | $2,250,878 |
| Routines | $2,860,814 | $3,001,170 |
| Meter Work | $8,443,283 | $9,003,511 |
| **Total Program** | **$18,876,849** | **$20,394,406** |

**Q. What is the basis for determining the $20,394,406 of O&M expenses in the test year as requested for this sub-program?**

A. The costs of the sub-program are primarily driven by Company gas service worker labor, materials, and vehicle expenses. Labor costs consider the amount of jobsite time needed to complete each work activity along with standard labor rates and indirect labor rates for the personnel completing the activity. The Company moved the work type no-gas investigation and repair from this program in 2024 to the Operations and Maintenance – Distribution sub-program. For this sub-program, the units and hours from 2023 to the test year are higher due to the increase in inactive meter removal, routine exchanges associated with rebuilds to top connect stands, and seal for non-pay turn on. Gas Service worker hourly standard labor rates are expected to be:

**Table 36**

| Service ($/hr) | | | | |
|---|---|---|---|---|
| | **Standard Labor Rates** | **Indirect Labor Rates** | **Vehicle Rates** | **Total Rate** |
| 2023 | $70.23 | $105.35 | $25.99 | $201.56 |
| 2024 | $73.80 | $98.15 | $22.14 | $194.09 |
| 2025 | $75.63 | $102.86 | $22.69 | $201.18 |
| 2026 | $78.52 | $106.79 | $23.56 | $208.86 |

This historical and projected activity in this program is summarized in the following table:

**Table 37**

| Operations & Maintenance – Customer Requested Services Units/Orders, Hours & Dollars | | | |
|---|---|---|---|
| **Year (Jan-Dec)** | **Units/Orders** | **Hours** | **Dollars** |
| 2016 | 216,935 | 105,474 | $14,468,136 |
| 2017 | 229,333 | 110,080 | $15,410,859 |
| 2018 | 211,300 | 106,027 | $15,885,423 |
| 2019 | 186,242 | 102,968 | $16,711,353 |
| 2020 | 134,870 | 73,132 | $12,113,609 |
| 2021 | 150,212 | 82,741 | $15,519,751 |
| 2022 | 160,647 | 92,868 | $19,198,250 |
| 2023 | 153,649 | 87,195 | $18,876,849 |
| 2024 Projected | 169,468 | 87,508 | $18,258,562 |
| 2025 Projected | 173,310 | 89,816 | $19,679,376 |
| 2025-2026 Test year | 174,514 | 90,356 | $20,394,406 |

The test year expense projection is based on a weighted average of the 2025 (16%) and 2026 (84%) forecast amounts, which reflect the Company's historical experience of program expense timing.

**Meter First Set Credits**

**Q. Please describe the Operations & Maintenance – Meter First Set Credits sub-program.**

A. The Operations & Maintenance – Meter First Set Credits sub-program offsets the initial labor costs to install a newly purchased natural gas meter (or First Set Cost), and the final

labor costs to remove the meter from service prior to retiring and scrapping the meter (or Cost of Removal). Meters are capitalized on purchase, per FERC accounting rules, and these credits offset the installation costs of the meters upon purchase and final disposal of meters.

The Company establishes an annual meter purchase plan for each year in June of the preceding year. That purchase plan provides for meter quantities and types, broken into periodic releases from meter manufacturers throughout the year, to meet all business requirements. Those requirements include new business sets, service upgrades, for-cause exchanges (such as damage, leak, and obsolescence), project work such as Enhanced Infrastructure Replacement Program ("EIRP"), and regulatory testing requirements. Factors considered when establishing the annual plan include current levels of inventory by meter type, assumptions of new business services expected in the coming year, historical for-cause exchange data, project work projections, historical trending for meter retirements, and regulatory program (i.e., the Routine Meter Exchange Program) projections. The plan calls for receiving shipments of meters at different points throughout the year, so the Company can adjust the orders as actual inventories are observed.

**Q. What is the basis for determining the $7,959,910 projected O&M credit in the test year?**

A. This O&M offset is primarily driven by the purchase of new gas meters. During the test year period, the Company plans to purchase 47,043 new gas meters. The expected credit from these purchases during the test year is $4,419,910. The credit is calculated monthly based on the standard labor rate of employees performing the work, the vehicle loading rate, and the indirect labor costs such as travel time that an employee spends performing

their work. This rate is applied to each meter purchased during that month based on the average time required to install the meter to determine the O&M first set credit.

During the test year period, the Company plans to retire 42,000 existing gas meters. The expected credit from these meter retirements is $3,540,000.

The cost of removal credit rate is calculated monthly based on the standard labor rate of employees performing the work, the vehicle loading rate, and the indirect labor costs incurred as employees perform the work. This rate is applied to each meter retired from service during that month based on the average time required to remove the meter from service to determine the O&M cost of removal credit. The annual dollar amount of first set credits is tied directly to the number of units of natural gas meters purchased.

The annual dollar amount of the cost of removal credits is directly tied to the number of units of natural gas meters retired from service during the year. Actual and projected amounts for 2016 through the test year are shown in the table below:

**Table 38**

| Operations & Maintenance – Meter Credits Units/Orders, Hours & Dollars | | | |
|---|---|---|---|
| **Year (Jan-Dec)** | **Units Purchased** | **Units Retired** | **Dollars** |
| 2016 | 73,707 | 53,518 | ($4,918,315) |
| 2017 | 77,380 | 55,846 | ($6,782,867) |
| 2018 | 65,471 | 50,654 | ($6,636,758) |
| 2019 | 61,570 | 43,207 | ($7,064,014) |
| 2020 | 58,997 | 42,471 | ($6,810,432) |
| 2021 | 49,759 | 38,230 | ($7,062,668) |
| 2022 | 20,902 | 39,631 | ($5,451,241) |
| 2023 | 35,200 | 65,222 | ($6,942,199) |
| 2024 Projected | 43,107 | 48,480 | ($8,104,000) |
| 2025 Projected | 47,546 | 42,000 | ($8,490,090) |
| 2025-2026 Test year | 47,043 | 42,000 | ($7,959,910) |

The test year expense projection is a weighted average of the 2025 (17%) and 2026 (83%) forecast amounts, which reflect the Company's historical experience of program expense timing.

**ROW Clearing**

**Q. Please describe the O&M expenses related to the ROW Clearing sub-program.**

A. The ROW Clearing sub-program expenses are needed for clearing and vegetation management for the Company's nearly 2,800 miles of natural gas transmission and storage field pipelines. The Company has historically performed minimum clearing necessary to complete inspections, repairs, replacement of pipe, and limited demand clearing for emergent work.

ROW clearing for gas transmission lines at a cyclical program level began in 2020. The projected test year amount of $2,047,934 will permit the continued clearing and herbicide treatment of approximately 400 miles of transmission line ROW per year.

This will place the natural gas transmission and storage pipeline system on an approximate seven-year clearing cycle to optimize the resources needed to maintain the ROW and prevent the growth of large trees that require hand cutting. A seven-year clearing cycle will allow the Company to create a sustainable integrated vegetation management program to minimize woody vegetation growth. This will also allow the gas transmission ROWs to be maintained at full width, increasing awareness for nearby property owners, and making encroachments on the ROW more visible. This seven-year cycle represents the maximum period between clearings to permit aerial patrol and ground line patrol, leak survey, and identify encroachments. The integrated vegetation management program promotes pollinator species and bird species dependent on early successional habitat, whose populations have been on the decline in the United States due to habitat loss. This additional environmental benefit does not affect the cost of the clearing program.

**Table 39**

| Right-of-Way Clearing | | |
|---|---|---|
| **Projection Breakdown by Activity Type** | | |
| **Work Type** | **2023 Actual** | **2025-2026 Test year** |
| Salary & Expenses | $219,714 | $254,637 |
| Mechanical Clearing Treatments | $1,274,254 | $1,476,792 |
| Herbicide Treatments | $273,097 | $316,505 |
| **Total Program** | **$1,767,066** | **$2,047,934** |

**Q. What is the basis for determining the $2,047,934 of projected O&M expenses in the test year for this sub-program?**

A. The projected expenses in this sub-program are primarily driven by the planned miles to be cleared and maintained. In Case No. U-20322, the Company proposed increased funding to implement a vegetation management program with a seven-year clearing cycle.

For the fourth full year of the plan implementation in 2023, the Company spent $1,767,066 and is targeting and on track to spend $1,623,888 in 2024.

The 2024 program includes the continued implementation of the herbicide treatment portion of the integrated vegetation management program, which is offset one year following mechanical clearing treatments. The Company is on track to continue to clear 400 miles annually, including herbicide as part of the integrated vegetation management program for ROW Clearing at the projected test year spending of $2,047,934. The projected cost increase reflects the program theoretically getting on cycle. So rather than continuing to reclaim the ROW as in previous years, the Company's intent is to reach a managing phase of the program. The 2020 actual miles and expense through the test year plan miles and expense are shown in the table below.

**Table 40**

| Right of Way Clearing | | |
|---|---|---|
| Miles & Dollars | | |
| | Miles | |
| Year (Jan-Dec) | Cleared | Dollars |
| 2016 | n/a | $86,364 |
| 2017 | n/a | $535,582 |
| 2018 | n/a | $1,095,233 |
| 2019 | n/a | $358,880 |
| 2020 | 412.6 | $1,147,835 |
| 2021 | 423.0 | $1,844,924 |
| 2022 | 304 | $1,827,267 |
| 2023 | 424 | $1,767,066 |
| 2024 Projected | 400 | $1,623,888 |
| 2025 Projected | 400 | $1,613,888 |
| 2025-2026 Test year | 400 | $2,047,934 |

The test year expense projection is a weighted average of the 2025 (9%) and 2026 (91%) forecast amounts, which reflect the Company's historical experience of program expense timing.

**Meter Reading**

**Q. Please describe the O&M expenses related to the Meter Reading sub-program.**

A. The Meter Reading sub-program includes Company employee labor, business expenses (such as fleet costs, and training), and technology expenses (hardware and software maintenance, cellular, and system improvements) for purposes of obtaining meter indexes for the calculation of customer bills.

The Company obtains meter indexes by three methods:

1. The mobile collection of meter indexes using AMR equipped vehicles on scheduled routes.
2. The automated collection of meter indexes using the Company's AMI meters.
3. The manual collection of meter indexes by walking up to meter installations to obtain reads.

The Company achieved overall year-end gas meter read rates of 99.76% in 2022 and 99.73% in 2023. The year-end meter reading results for 2022 and 2023 for the various processes used by the Company are as follows:

**Table 41**

| | Meters Available | | Meters Read | | Meter Read Rate | |
|---|---|---|---|---|---|---|
| **Year** | **2022** | **2023** | **2022** | **2023** | **2022** | **2023** |
| **Gas AMR** | 13,699,110 | 13,787,192 | 13,685,051 | 13,767,861 | 99.90% | 99.86% |
| **Gas AMI** | 8,006,601 | 8,047,105 | 7,986,287 | 8,023,901 | 99.75% | 99.71% |
| **Manual Gas Reads** | 168,382 | 159,831 | 150,886 | 143,063 | 89.61% | 89.51% |

The Meter Reading sub-program is managed jointly for the Company's electric and natural gas operations. As a result, the total meter reading costs are allocated between

electric and natural gas. The average gas/electric allocation for the test year is projected to be 39% electric and 61% gas; in 2023, the allocation was split 38.8% electric and 61.2% gas. The difference between the 2023 actual and projected test year electric and gas allocation considers the optimization of AMR and manual routes.

A comparison of the 2023 actual and test year projection is provided below:

**Table 42**

| Meter Reading | | |
|---|---|---|
| **Projection Breakdown by Activity Type** | | |
| **Work Type** | **2023 Actual** | **2025-2026 Test year** |
| Meter Reader Salaries | $294,822 | $317,050 |
| Supervision & Administration Salaries | $1,555,897 | $1,673,203 |
| Meter Reading Expenses | $756,696 | $813,747 |
| **Total Program** | $2,607,415 | $2,804,000 |

**Q. What is the basis for determining the $2,804,000 of projected O&M expenses in the test year for this sub-program?**

A. Spending in this sub-program is primarily driven by Company employee labor, business, and technology expenses. The test year projected expense is $2,804,000, which is an increase of $196,585 because of increased technology fees and annual labor salary increases.

For the test year, the number of gas meter reader operating employees is projected to be 22 employees. These employees will navigate AMR mobile collection vehicles and continue to manually read approximately 14,790 gas meters.

The manual reads occur for the following reasons: opt-out customers (Opt Out Not Cut Over), out of scope meters (i.e., commercial/industrial meters) (Not Cut Over), and rate not eligible accounts (Rates ineligible).

The table below shows this breakdown as well, separated between Legacy and Smart meter customers:

**Table 43**

| August 2024 | |
|---|---|
| **Gas Customers Not Cut Over To AMI/AMR** | |
| **Description** | **Manually Read Meters Count** |
| Legacy Not Cut Over | 4,162 |
| Legacy Opt Out Not Cut Over | 5,293 |
| Legacy Rates Ineligible for GCM | 2,649 |
| **Total Legacy Not Cut Over** | **12,104** |
| | |
| GCM AMR Not Cut Over | 941 |
| GCM AMR Opt Out Not Cut Over | 0 |
| GCM AMR Rates Ineligible | 903 |
| GCM AMI Not Cut Over | 608 |
| GCM AMI Opt Out Not Cut Over | 0 |
| GCM AMI Rates Ineligible | 160 |
| **Total Smart Not Cut Over** | **2,612** |
| **GRAND TOTAL NOT CUTOVER** | **14,716** |

The following table provides the actual meter reading O&M cost for 2016 through 2023, as well as forecasted amounts for 2024 through the test year:

**Table 44**

| Meter Reading | | |
|---|---|---|
| Equivalent Staffing & Dollars | | |
| | Average | |
| Year (Jan-Dec) | Gas Staff | Dollars |
| 2016 | | $13,582,033 |
| 2017 | | $12,328,228 |
| 2018 | 112 | $10,499,528 |
| 2019 | 67 | $7,633,272 |
| 2020 | 31 | $4,097,383 |
| 2021 | 23 | ~~$~~2,830,688 |
| 2022 | 22 | $2,592,247 |
| 2023 | 22 | $2,607,415 |
| 2024 Projected | 22 | $2,567,867 |
| 2025 Projected | 22 | $2,624,385 |
| 2025-2026 Test year | 22 | $2,804,000 |

The expense projection for the test year is a weighted average of the 2025 (17%) and 2026 (83%) forecast amounts, which reflect the Company's historical experience of program expense timing.

**Meter Technology and Management System Support**

**Q. Please describe the O&M expenses related to the Meter Technology and Management System Support sub-program.**

A. The Meter Technology and Management System Support sub-program ensures the safety, accuracy, maintenance, and stability of the Company's natural gas metering equipment. This program supports the verification of meter accuracies for all customer classes. The program costs are associated with testing and refurbishing gas meters, instrument correctors, gas communication modules, and regulators in response to the Company's Routine Meter Exchange Program.

In July of 2020, the Company combined the Meter Technology Center ("MTC") and the Smart Energy Operations Center ("SEOC") into one combined operation. The

SEOC Program includes the gas portion of the labor and expenses relating to the SEOC daily responsibilities in connection with obtaining AMR meter reads. This includes troubleshooting the equipment, order creation, and IT system demand requirements.

The SEOC is responsible for the reliability and data delivery of the AMI electric meters and AMR gas communication modules. Electric-related costs are not included in this filing. The SEOC benefits customers by providing actual meter reads, minimizing the number of estimated bills, and providing reliable and timely data through daily AMI and monthly AMR meter interrogations.

The 2023 historical expense and the test year projected expense are summarized in the following table:

**Table 45**

| Meter Tech & Mgmt Sys Support | | |
|---|---|---|
| **Projection Breakdown by Activity Type** | | |
| **Work Type** | **2023 Actual** | **2025-2026 Test year** |
| Exempt/Non-Exempt Salaries | $206,101 | $224,490 |
| OM&C Salaries | $740,763 | $806,857 |
| Expenses | $338,454 | $368,652 |
| Meter Correctors (began to purchase as O&M in 2022) | $246,460 | $2,598,000 |
| **Total Program** | $1,531,778 | $3,998,898 |

**Q. What is the basis for determining the $3,998,898 projected O&M expenses in the test year for this sub-program?**

A. This sub-program expense is primarily driven by labor, operating, and material costs.

In 2021, a determination was made relative to stand-alone natural gas meter correctors, which had previously been purchased under the Gas Meters capital program, that the components were considered replacement parts and would be purchased under the O&M program going forward, starting in 2022. The change in purchasing instrument

correctors in this program represents a $2,598,000 impact in the test year, purchasing 4,354 ~~2,190~~ stand-alone units. The test year projected program requirement represents normal business expenses with the change in categorization of the gas meter corrector purchases. The following table provides the actual O&M cost for 2016 through 2023, as well as forecasted amounts for 2024 through the projected test year:

**Table 46**

| Meter Tech & Mgmt Sys Support Dollars | | | |
|---|---|---|---|
| | Labor | Other | Total |
| Year (Jan-Dec) | Dollars | Dollars | Dollars |
| 2016 | $1,198,957 | $67,162 | $1,266,120 |
| 2017 | $1,218,563 | $64,613 | $1,283,175 |
| 2018 | $1,265,965 | $82,867 | $1,348,832 |
| 2019 | $1,227,567 | $85,006 | $1,312,573 |
| 2020 | $1,040,289 | $45,134 | $1,085,423 |
| 2021 | $1,055,672 | $213,094 | $1,268,766 |
| 2022 | $1,106,459 | $320,326 | $1,426,785 |
| 2023 | $950,010 | $581,768 | $1,531,778 |
| 2024 Projected | $1,048,202 | $1,059,850 | $2,109,560 |
| 2025 Projected | $1,119,870 | $2,711,130 | $3,831,000 |
| 2025-2026 Test year | $1,031,348 | $2,967,550 | $3,998,898 |

The test year expense projection is a weighted average of the 2025 (19%) and 2026 (81%) forecast amounts and reflect the Company's historical experience of program expense timing.

**Smart Energy Metering Technology Center**

**Q. Please describe the O&M expenses related to the Smart Energy Metering Technology Center sub-program.**

A. The Smart Energy Metering Technology Center sub-program includes:

(i) The gas portion of expenses related to software maintenance for gas communications modules installed on locations in which the module communicates data through the electric meter.

(ii) The gas portion of the cellular communication expenses allocated to gas communication modules that pass data through the electric meter.

(iii) The gas portion of a technical support contract with the Company's AMI/AMR vendor.

These costs are contractually based through 2032 on a per meter or communication module basis.

**Table 47**

| Smart Energy MTC – Gas | | |
|---|---|---|
| **Projection Breakdown by Activity Type** | | |
| **Work Type** | **2023 Actual** | **2025-2026 Test year** |
| Communication Charges | $250,982 | $255,609 |
| GCM Software Maintenance | $167,860 | $170,954 |
| Technical Support Services Contract | $125,000 | $127,304 |
| **Total Program** | $543,842 | $553,867 |

**Q. What is the basis for determining the projected O&M expenses in the test year for this sub-program?**

A. The projected expense is based on the number of units of AMI-programmed gas modules installed in the field and in inventory to support operations.

With the completion of deployment, the AMI gas module population, subject to a portion of the cellular and software maintenance expenses, has stabilized at a level to include all installed meters and inventory required to support new installations going forward. This should also provide for replacement of existing meters for cause (an error/malfunction) or routine exchange requirements. In addition, per the contract that runs through 2032, the software maintenance expense per unit increases 3% per year. Actual and projected amounts for 2016 through the test year, are shown in the table below:

**Table 48**

| Smart Energy MTC – Gas Dollars | |
|---|---|
| | Total |
| Year (Jan-Dec) | Dollars |
| 2016 | 0 |
| 2017 | $846,677 |
| 2018 | $598,586 |
| 2019 | $606,147 |
| 2020 | $542,619 |
| 2021 | $565,536 |
| 2022 | $542,948 |
| 2023 | $543,842 |
| 2024 Projected | $554,888 |
| 2025 Projected | $553,867 |
| 2025-2026 Test year | $553,867 |

The test year expense projection is a weighted average of the 2025 (13%) and 2026 (87%) forecast amounts, which reflect the Company's historical experience of program expense timing.

**Gas Storage**

**Q. Please describe the O&M expenses related to the Gas Storage sub-program.**

A. Gas Storage sub-program O&M expenses are directly associated with various maintenance and operational tasks purposed to ensure the predictable and safe operation of the natural gas storage system. The natural gas storage system includes 15 gas storage fields, 808 gas storage wells, and 244 miles of gathering lines, with associated valving, conditioning systems, and access roads. The program funds critical tasks associated with operability and regulatory compliance. Tasks that are executed annually through this sub-program include valve and operator inspections, line patrol and leak survey, integrity monitoring, inspection and maintenance of regulators and relief valves, surface and subsurface safety valves,

isolation valves, fluid separators, and fluid disposal systems. In addition, the Gas Storage O&M sub-program ensures near real-time emergency response preparedness.

This sub-program includes the following work activity categories:

- Non-WBS portion of the sub-program includes labor, internal departmental chargebacks, contractors, and materials not directly associated with a specific work order.

- Contractor Materials, Credits and Other Expenses portion of the sub-program includes contractor labor, credits, and materials for Code Inspection, Facilities Locating for Third Parties (MISS DIG 811), Demand/Preventive/Compliance Maintenance and Operations which are directly associated with a specific work order.

- Code inspections and compliance work is in adherence to all applicable local, state, and federal laws, including those implemented by the MPSC, EGLE, PHMSA, Environmental Protection Agency, Bureau of Land Management, and Michigan Occupational Safety and Health Administration. Regulatory Maintenance activities include pigging activities, corrosion prevention, dehydrator and separator preventative maintenance, valve and operator inspection and repair, access road maintenance, regulator and relief inspections, pipeline patrol, and leak survey to ensure public safety.

- Operation and integrity work includes the bi-annual pressure survey of all 15 fields for reservoir integrity and inventory verification, monthly wellhead pressure monitoring to ensure asset integrity and deliverability, configuring of gas storage fields for injection/withdraw cycles, and routine inspection of assets during winter operations/peak demand.

- Demand maintenance has trended consistent historically. Drivers of these costs include gas storage well intervention, integrity demonstration, and issues affecting gas flow deliverability. This may include well intervention, well logging, freezes in pipelines, snow plowing to ensure access facilities, and response to periodic equipment and system failures requiring intervention and corrective measures to maintain reliability and public safety.

The historical year costs and projected test year costs for this program are summarized in the following table:

**Table 49**

| Gas Storage O&M<br>Projection Breakdown by Activity Type | | |
|---|---|---|
| **Work Type** | **2023 Actual** | **2025-2026 Test year** |
| Non-WBS | $1,699,628 | $1,456,458 |
| Contractor; Materials, Credits and Other Expenses | $909,821 | $910,911 |
| Code Inspections | $1,559,900 | $1,548,457 |
| Facilities Locating for Third Parties (MISS DIG 811) | $828,615 | $822,537 |
| Demand/Preventive/Compliance Maintenance | $890,681 | $884,147 |
| Operations | $53,032 | $52,643 |
| Less: Facility Chargebacks | ($202,567) | ($202,567) |
| **Total Program** | $5,739,110 | $5,472,586 |

**Q. What is the basis for determining the $5,472,586 of projected O&M expenses in the test year for this sub-program?**

A. The projected expense for this sub-program is historically based, and primarily driven by known units (labor hours) and historical actuals execution of tasks associated with the following activities: compliance inspections, maintenance inspections, operation of the gas storage facilities to meet gas flow deliverability needs and third-party damage prevention tasks (such as locate/stake, crossings, and contractor oversight) to ensure public safety, code compliance, maintenance of critical assets, and operation of the system to deliver natural gas across the state.

These tasks include monthly well site visits and operational support of the Annular monitoring program, including well intervention. Gas transmission worker hourly standard labor rates are expected to be:

**Table 50**

| Transmission ($/hr) | | | | |
|---|---|---|---|---|
| | **Standard Labor Rates** | **Indirect Labor Rates** | **Vehicle Rates** | **Total Rate** |
| 2023 | $69.18 | $24.90 | $36.67 | $130.75 |
| 2024 | $72.53 | $23.93 | $34.81 | $131.28 |
| 2025 | $76.37 | $26.73 | $32.08 | $135.17 |
| 2026 | $79.28 | $27.75 | $33.30 | $140.33 |

The historical and projected activity in this sub-program are summarized in the following table:

**Table 51**

| Gas Storage O&M Dollars | |
|---|---|
| **Year (Jan-Dec)** | **Dollars** |
| 2016 | $7,062,022 |
| 2017 | $5,667,339 |
| 2018 | $6,305,807 |
| 2019 | $6,187,826 |
| 2020 | $5,821,338 |
| 2021 | $5,860,452 |
| 2022 | $6,338,065 |
| 2023 | $5,739,110 |
| 2024 Projected | $5,355,743 |
| 2025 Projected | $4,771,940 |
| 2025-2026 Test year | $5,472,586 |

The test year expense projection is a weighted average of the 2025 (12%) and 2026 (88%) forecast amounts, which reflect the Company's historical experience of program expense timing. The test year expense is lower due to the following factors: maintenance is decreasing due to abandonment of some facilities (wells), and increased compliance inspections leading to less equipment-related failure.

**Replace Vintage Services**

**Q. Please describe the O&M expenses related to the Replace Vintage Services ("RVS") sub-program.**

A. The O&M expenses for RVS sub-program occur because a small percentage of planned capital RVS orders are not able to be completed as planned.

Reasons for these orders not being completed include field crew identification of services that are already plastic, construction barriers such as service connections to mains that exist under construction barriers such as poles or trees, field crew identification of forced sewer facilities, meters that are not reasonably accessible, excessive main depth, high ground water conditions, evidence of other underground facilities that were unable to be located, and orders for branch services that do not qualify as capital assets.

The historical year costs and projected test year costs for this program are summarized in the following table:

**Table 52**

| Replace Vintage Services | | |
|---|---|---|
| **Projection Breakdown by Activity Type** | | |
| **Work Type** | **2023 Actual** | **2025-2026 Test year** |
| Replace Vintage Services | $13,897 | $70,926 |
| **Total Program** | **$13,897** | **$70,926** |

**Q. What is the basis for determining the $70,926 of projected O&M expenses in the test year for this sub-program?**

A. The forecast for 2025 and 2026 anticipates that a small percentage of RVS construction orders will be returned from the field as non-constructible. The Company plans to replace

4,164 services in 2025 and 5,913 services in 2026. The expected non-constructible rate is expected to be 1.30% of planned units.

The historical and projected activity in this sub-program is summarized in the following table:

**Table 53**

| Operations & Maintenance – Replace Vintage Services Units/Orders, Return Rate & Dollars | | | |
|---|---|---|---|
| **Year (Jan-Dec)** | **VSR Planned Units** | **Return Rate** | **Dollars** |
| 2016 | NA | NA | NA |
| 2017 | 6,307 | | $1,324 |
| 2018 | 9,381 | | $102,593 |
| 2019 | 5,571 | | $90,072 |
| 2020 | 5,456 | | $83,994 |
| 2021 | 5,056 | 1.25% | $298,453 |
| 2022 | 2,176 | 1.25% | $98,417 |
| 2023 | 1,228 | 1.4% | $13,897 |
| 2024 Projected | 2,424 | 1.30% | $70,289 |
| 2025 Projected | 4,164 | 1.30% | $70,289 |
| 2025-2026 Test year | 5,913 | 1.30% | $70,926 |

The test year expense projection is a weighted average of the 2025 (36%) and 2026 (64%) forecast amounts, which reflect the Company's historical experience of program expense timing.

**Gas Operations Field Operations**

**Q. Please describe the O&M expenses related to the Gas Field Operations sub-programs shown on Exhibit A-88 (JPP-3).**

A. The Gas Field Operations sub-programs includes training for approximately 1,500 natural gas field operations employees.

Also included is training for the Company's gas construction workforce, small tools, natural fiber clothing, safety equipment, field operation expenses, labor and expenses for personnel who are responsible for statewide scheduling and assignment of requested work, and management and administrative personnel of Gas Operations to ensure the safe and effective operation of the gas facilities.

**Training**

**Q. Please describe the O&M expenses related to the Training sub-program.**

A. The Training sub-program includes training for approximately 1,500 natural gas field operations employees, including Operator Qualification ("OQ") training, in accordance with applicable regulations. Examples of training provided under this sub-program include equipment operator, pipe joining, valve inspection and maintenance, welding, and pressure control (regulation).

Safety training is also included in this program, which drives improved safety performance in gas field operations. Gas field operations employees receive training each year to ensure a highly skilled workforce qualified to safely operate, maintain, and execute the tasks necessary to meet customer and work demands.

The historical year costs and projected test year costs for this program are summarized in the following table:

**Table 54**

| Operation & Maintenance – Training Projection Breakdown by Activity Type | | |
|---|---|---|
| **Work Type** | **2023 Actual** | **2025-2026 Test year** |
| Gas Operations OM&C Training | $4,330,190 | $4,507,764 |
| Athletic Trainers | $313,140 | $245,045 |
| Gas Training Non-Labor Expense | $92,353 | $91,440 |
| **Total Program** | **$4,735,683** | **$4,844,249** |

**Q. What is the basis for determining the $4,844,249 of projected O&M expenses in the test year for this sub-program?**

A. Spending in this sub-program is primarily driven by the hours of training conducted for Gas Operations employees. This training is required to ensure a skilled and qualified field operations workforce is available that can complete all customer-requested and compliance-based tasks.

The historical and projected activity in this program is summarized in the following table:

**Table 55**

| Training Hours & Dollars | | |
|---|---|---|
| **Year (Jan-Dec)** | **Training Hours** | **Dollars** |
| 2016 | 77,351 | $5,141,541 |
| 2017 | 74,539 | $5,718,735 |
| 2018 | 100,790 | $6,786,833 |
| 2019 | 83,324 | $6,145,865 |
| 2020 | 50,033 | $4,698,219 |
| 2021 | 85,722 | $6,246,682 |
| 2022 | 83,518 | $6,205,592 |
| 2023 | 73,753 | $4,735,683 |
| 2024 Projected | 60,679 | $4,150,817 |
| 2025 Projected | 68,430 | $4,607,108 |
| 2025-2026 Test year | 69,749 | $4,844,249 |

The test year expense projection is a weighted average of the 2025 (14%) and 2026 (86%) forecast amounts, which reflect the Company's historical experience of program expense timing.

**Tools**

**Q. Please describe the O&M expenses related to the Tools sub-program.**

A. The Tools sub-program includes the acquisition of small tools, natural fiber clothing, and safety items for field employees.

This ensures employees complete field work in a safe, efficient, and effective manner. Natural Fiber clothing is a required personal protective equipment provided by the Company for employees in the field and who may be exposed to an area where natural gas is present.

Tools included in this sub-program are small hand tools, and any tool used in the field that had an original cost of less than $1,000. Fusion equipment, drills, grinders, and clamps are examples of tools that would be purchased under this program.

**Q. What is the basis for determining the $1,431,000 of projected O&M expenses in the test year for this sub-program?**

A. The projected expense for this sub-program is based on historical levels as well as any known work plan needs and headcount changes for the test year period. The historical and projected activity in this program is summarized in the following table.

**Table 56**

| Tools | |
|---|---|
| **Dollars** | |
| **Year (Jan-Dec)** | **Dollars** |
| 2016 | $1,805,705 |
| 2017 | $1,938,712 |
| 2018 | $2,136,931 |
| 2019 | $1,702,554 |
| 2020 | $1,785,981 |
| 2021 | $1,691,000 |
| 2022 | $3,065,612 |
| 2023 | $1,827,711 |
| 2024 Projected | $1,438,372 |
| 2025 Projected | $788,998 |
| 2025-2026 Test year | $1,431,000 |

The test year expense projection is a weighted average of the 2025 (16%) and 2026 (84%) forecast amounts, which reflect the Company's historical experience of program expense timing.

**Field Operations**

**Q. Please describe the O&M expenses related to the Field Operations Expenses sub-program.**

A. The Field Operations Expenses sub-program includes operating employee expenses, telephone/computer chargebacks, environmental fees, gas pipeline user fees, transmission flight operations (aerial surveys), and other miscellaneous expenses.

Primary drivers for this sub-program's expenses are operating employee miscellaneous expenses, pipeline user fees, and permits. Operating employee miscellaneous expenses include items such as costs for mileage, hotels for Company-related trips, permit fees, and telephone and computer charges.

Pipeline user fees are fees paid to the PHMSA section of the United States Department of Transportation for gas distribution and gas transmissions lines. Details regarding the actual O&M expenses in 2023 and the projected test year expenses are provided in the table below:

**Table 57**

| Field Operations Expenses | | |
|---|---|---|
| **Projection Breakdown by Activity Type** | | |
| **Work Type** | **2023 Actual** | **2025-2026 Test year** |
| Field Ops OM&C Gas Expenses | $1,752,881 | $1,433,578 |
| Field Ops OT Meals Gas | $287,835 | $320,088 |
| Pipeline User Fees | $696,966 | $847,620 |
| Permits | $95,831 | $74,640 |
| Gas Field Mobility Exp | $294,525 | $347,922 |
| Gas Bonds | $334,514 | $600,000 |
| **Total Program** | **$3,462,552** | **$3,623,848** |

**Q. What is the basis for determining the $3,623,848 of projected O&M expenses in the test year for this sub-program?**

A. The projected test year expense in this sub-program is based on historical spend levels as well as any known work plan needs for the test year period. The reason for this increase in spending is driven primarily by increased bond purchase costs.

**Table 58**

| Field Operations Expenses | |
|---|---|
| Dollars | |
| **Year** | **Dollars** |
| 2016 | $4,070,748 |
| 2017 | $4,039,347 |
| 2018 | $3,223,396 |
| 2019 | $3,133,706 |
| 2020 | $2,964,197 |
| 2021 | $3,709,349 |
| 2022 | $3,899,805 |
| 2023 | $3,462,552 |
| 2024 Projected | $3,776,000 |
| 2025 Projected | $2,727,234 |
| 2025-2026 Test year | $3,623,848 |

The test year expense projection is a weighted average of the 2025 (9%) and 2026 (91%) forecast amounts, which reflect the Company's historical experience of program expense timing.

**Indirect Labor/Labor Variation**

**Q. Please describe the Indirect Labor/Labor Variation O&M Expense.**

A. The Indirect Labor/Labor Variation expense supports the difference between the Company's actual operating employees' wages and the amount of salary cost allocated to work orders, using standard labor rates. Indirect Labor Variation occurs when the Company has labor costs not directly related to a work order, such as travel time between jobs, that has not been allocated to a work order via the indirect labor loading. The Company attempts to clear these account balance variances by year end. Thus, the Company does not project any test year expense in this sub-program.

**Supervision/Admin Staff**

**Q. Please describe the O&M expenses related to the Supervision/Admin Staff sub-program.**

A. The Supervision/Admin Staff sub-program provides for the management and administrative personnel for Gas Operations to ensure the safe and effective operation of the gas facilities. Operational supervision helps ensure the safety of crews working in the field as well as the safe execution of work practices.

This section combines the Supervision/Admin Staff - Distribution, Supervision/Admin Staff - Services, and Supervision/Admin Staff - Transmission & Storage sub-programs that are shown individually on Exhibit A-88 (JPP-3) page 1, lines 5, 6, and 7.

**Q. What is the basis for determining the $5,811,757 of projected O&M expenses in the test year for this sub-program?**

A. The projected expense in this sub-program is primarily driven by labor and expenses. In 2021, this program only included employees from Gas Service and Gas Distribution. During 2022, Gas Transmission and Storage, which encompasses M&R and Pipeline, was added to this sub-program.

In September 2023, the Gas Operations Support and Gas Contractor Oversights Teams, formerly part of the Operations Compliance and Controls sub-program, were added to this sub-program. These departments consist of the following areas focused on enhancing the Company's compliance to regulatory requirements and ensuring proper controls.

The following functions were added to the sub-program:

- OQ and the gas operations certification training program ensure the Company's field workforce is qualified to perform its work obligations on the gas system.

- Management of the Company's operational compliance quality assurance processes and systems for identification of risks and opportunities across the Company's gas facilities and operations. This is accomplished through the implementation of preventative and detective controls to manage compliance with state and federal regulatory requirements and an effectiveness verification approach.

- Contractor oversight and management for construction contractors performing work on behalf of the Company on the gas system. This also includes expenses for technology and standardization to achieve remote inspection, governance around contractor oversight, and sewer/cross bore program.

Effective in 2023, the Distribution program includes the labor, expenses, and chargebacks for these employees. The historical year costs and projected test year costs and headcounts are summarized in the following table:

**Table 59**

| Year (Jan – Dec) | Distribution Headcount | Service Headcount | T&S Headcount | Total Headcount | Dollars |
|---|---|---|---|---|---|
| 2021 | 151 | NA | 27 | 178 | $6,819,841 |
| 2022 | 102 | 48 | 24 | 174 | $5,345,649 |
| 2023 | 117 | 47 | 15 | 179 | $5,576,984 |
| 2024 Projected | 115 | 45 | 18 | 178 | $5,515,440 |
| 2025 Projected | 115 | 46 | 18 | 179 | $5,676,659 |
| 2025-2026 Test year | 115 | 46 | 18 | 179 | $5,811,757 |

Headcount is expected to be flat from 2023 through the test year. The test year expense projection for the test year is a weighted average of the 2025 (17%) and 2026 (83%) forecast amounts, which reflect the Company's historical experience of program expense timing.

**Dispatch & Scheduling**

**Q. Please describe the O&M expenses related to the Dispatch & Scheduling sub-program.**

A. The Dispatch & Scheduling sub-program includes the labor and expenses for personnel who are responsible for efficiency and consistency in statewide scheduling and assignment of emergent, compliance, and customer requested work.

The Dispatching function operates 24 hours per day, 365 days per year in three locations across the state. The Scheduling and Meter Reading support operates during normal business hours and the associated overtime hours as work volume fluctuates throughout the year.

*Emergent work* consists of odor response investigations, emergent leak repairs, and third-party damage response and repair.

*Compliance work* consists of work order coordination, creation, and assignment of gas meter routine exchange program, and planned leak and non-leak maintenance work.

*Customer-requested work* consists of meter turn on/off, seal for nonpayment turn on, issue investigations, and meter upgrades.

This sub-program is also responsible for assigning meter reading routes to technicians and associated troubleshooting. Additionally, it is also responsible for the gas meter Consecutive Estimate Program, which manages customer accounts (approximately 1,000) with three or more consecutive estimates through an escalation process. Escalation includes tracking and reporting of accounts, manual and automated phone calls, postcard and letter mailings, scheduling of appointments, and coordination with other departments

and customers to resolve meter access issues. The actual O&M expenses in 2023 and the projected test year expenses are provided in the table below:

**Table 60**

| Dispatch and Scheduling | | |
|---|---|---|
| **Projection Breakdown by Activity Type** | | |
| **Work Type** | **2023 Actual** | **2025-2026 Test year** |
| Dispatch and Scheduling | $1,179,714 | $1,278,488 |
| **Total Program** | $1,179,714 | $1,278,488 |

**Q. What is the basis for determining the $1,278,488 for Scheduling and Dispatch expenses in the test year for this sub-program?**

A. The projected expense in this sub-program is primarily driven by customer-requested demand, including short cycle demand, such as emergency and service calls in addition to gas meter reading work assignment and Consecutive Estimate Program activities. Response to customer and emergent demand requires appropriate levels of personnel to plan, schedule, and dispatch the associated work. This sub-program includes the labor costs and expenses for these personnel.

In 2021, this financial program was separated from a larger program with responsibility for the identified work activities and long cycle work planning, scheduling, and closeout.

**Table 61**

| Dispatch and Scheduling Dollars | |
|---|---|
| **Dollars** | |
| **Year** | **Dollars** |
| 2016 | n/a |
| 2017 | n/a |
| 2018 | n/a |
| 2019 | n/a |
| 2020 | n/a |
| 2021 | $1,465,488 |
| 2022 | $1,371,650 |
| 2023 | $1,179,714 |
| 2024 Projected | $1,101,852 |
| 2025 Projected | $1,239,000 |
| 2025-2026 Test year | $1,278,488 |

The test year expense projection is a weighted average of the 2025 (16%) and 2026 (84%) forecast amounts, which reflect the Company's historical experience of program expense timing.

**EIRP**

**Q. Please describe the O&M expenses related to the EIRP sub-program.**

A. These expenses include training for the Company's gas construction workforce, salaries and expenses for the field supervisors and managers, tools, and facilities maintenance. These expenses ensure that the seasonal workforce is properly staffed, trained, and has the necessary tools and facilities.

**Table 62**

| EIRP O&M | | |
|---|---|---|
| **Projection Breakdown by Activity Type** | | |
| **Work Type** | **2023 Actual** | **2025-2026 Test year** |
| EIRP Supervision & Admin Sal/Exp | $869,933 | $945,439 ~~685,299~~ |
| EIRP Tools | $84,056 | $41,757 |
| EIRP OM&C Expenses (Non-Labor) | $10,059 | $0 ~~260,140~~ |
| EIRP Facilities | $251,148 | $271,422 |
| EIRP Labor OM&C Training | $2,132,942 | $3,789,331 |
| **Total Program** | **$3,348,137** | **$5,047,949** |

**Q. What is the basis for determining the $5,047,948 of projected O&M expenses in the test year for this sub-program?**

A. Approximately 75-80% of the expense in this program is the technical training required to ensure the field employees are fully skilled and qualified to complete the EIRP work. This includes initial training for newly hired employees, as well as more advanced training for higher skilled employees. Along with technical training, expenses in this sub-program include annual refresher training covering standards and policy changes, along with safety procedural changes.

The EIRP workforce is one of the largest hiring groups in the Company to meet the demand of the total gas construction activities (including gas asset replacement and relocation programs as well as the Infrastructure Replacement Program). The EIRP workforce continues to experience employees transferring to other operating departments within the Company.

Along with this employee movement, hiring and training are planned to allow for appropriate staffing as the Company implements the NGDP. Based on projections, this will result in increased spending compared to 2023. This increase is due to additional training needed for the complexity of the EIRP work plan, and for training new hires to maintain

the workforce. As the NGDP progresses, this level of staffing and training is expected to moderate.

In addition to training field personnel, this program also equips those employees with necessary tools and facilities. Facility expenses largely consist of the eight Headquarters sites for the group (located in Saginaw, Lansing, Livonia, Macomb, Flint, Midland, Jackson, and Royal Oak). These costs are driven by the planned work activities that are based on the amount of vintage pipe to be replaced. The facility expenses also include the O&M portion of the total lease payment for the facilities. Lease payments are discussed in the testimony of Company witnesses Kristine A. Pascarello and Quentin A. Guinn. This program expense also experiences inflationary effects as nearly all sites are leased or rented.

Leadership oversight of the approximately 550 field employees, including contractors, in the EIRP workforce is necessary to ensure regulatory compliance, provide instruction for field employee training, and confirm OQs are in place. The projected test year costs for this function are consistent with historical expenses. The historical and projected cost summary is shown in the below table:

**Table 63**

| EIRP O&M Dollars | |
|---|---|
| **Year (Jan-Dec)** | **Dollars** |
| 2016 | $2,309,424 |
| 2017 | $2,415,780 |
| 2018 | $1,996,035 |
| 2019 | $2,496,230 |
| 2020 | $5,462,735 |
| 2021 | $3,681,670 |
| 2022 | $4,370,398 |
| 2023 | $3,348,137 |
| 2024 Projected | $3,051,022 |
| 2025 Projected | $3,367,718 |
| 2025-2026 Test year | $5,047,948 |

The test year expense projection is a weighted average of the 2025 (6%) and 2026 (94%) forecast amounts, which reflect the Company's historical experience of program expense timing.

**Work Management and Customer Delivery**

**Q. Please describe the expenses related to the Work Management and Customer Delivery O&M Program shown on Exhibit A-89 (JPP-4).**

A. The Gas Operations Performance ("Ops Performance") Department represented a department within the Consumers Energy Operations organization that began in 2017. The Ops Performance team included experts in work planning, project management, scheduling, administration, data analytics, data science, Lean Operating Systems, process engineering, industrial engineering, standards management, and technology. This department consisted of the following functions focused on streamlining processes to achieve first-time quality for our customers:

(1) Work Management Excellence,

(2) Process, Analytics & Technology, and

(3) Industrial Engineering.

In 2024, the Process, Analytics & Technology, and Industrial Engineering departments moved to other organizations within the Company. The Work Management Excellence department remained and was renamed Work Management and Customer Delivery. Their function is described below.

- Work Management and Customer Delivery includes functions for Distribution Planning, Scheduling, Close-Out, Statewide Admin, and Customer Energy Management (CEM) for long-cycle work. Long-cycle work includes new business requests, gas facility relocates, planned maintenance, alterations, demolitions, gas leak repair, and capacity/augmentation.
  - Planning ensures the operating plan adheres to the MPSC-approved business plan for Gas Operations field work.
  - Scheduling ensures field crews have enough work, ready-work, and the right work and resources to complete the work plan.
  - The Close Out and Admin functions ensure technical documentation is accurate and complete, and that the costs of the work settle appropriately to the work orders and comply with Sarbanes-Oxley rules for capital and O&M work.
  - In addition to Planning, Scheduling, Close-Out, and Admin functions, the Work Management and Customer Delivery Team assumed responsibility, costs, and headcount of the Customer Energy Management ("CEM") team from Gas Engineering in 2023 and retained Operations Process and Technology functions.
  - The CEM team is focused on meeting customer needs by providing a single point of contact for customer-requested main, service, and meter installations and alterations. CEM is responsible for ensuring all new customer service requests and customer-requested alterations on the Company's distribution system are coordinated from initiation through completion to meet customer expectations.
  - Within CEM, there are four departmental areas of focus.
    - The Zonal Project Coordination team is responsible for customer interaction and project coordination for all new business gas main extensions in their respective geographical region.

- The Gas Customer Attachment Program ("CAP") team coordinates the completion of projects which expand the natural gas system into areas that are just adjacent to the current system limits, where more concentrated pockets of potential customers are located, and administration of CAP project tracking and CAP payments. Even with the conclusion of proactive CAP main installation in 2019, this team remains intact to facilitate the tracking of projects and administer the CAP payments associated with the previously installed mains and services per the tariff requirements.

- The CEM team is also responsible for "Express Design" services for all residential service requests within subdivisions, workload coordination and balancing, as well as other design support related tasks, including billing, permitting, and inspection. This organizational re-alignment has aligned like work with like work and provides efficiencies in the work management process.

- The Operations Process and Technology teams provide support for process improvement, standardization, and systems used by Gas Operations, for functions such as project management, scheduling, work management, field order management, field call-out, and meter reading. These resources provide subject-matter expertise, performance coaching, documentation, change management, and technology analysis for changes across the work management process to improve the customer experience.

**Table 64**

| Work Management and Customer Delivery | | |
|---|---|---|
| **Projection Breakdown by Activity Type** | | |
| **Work Type** | **2023 Actual** | **2025-2026 Test year** |
| Work Management and Customer Delivery | $3,005,111 | $2,539,000 |
| **Total Program** | **$3,005,111** | **$2,539,000** |

**Q. What is the basis for determining the projected $2,539,000 O&M expenses in the test year for this program?**

A. The projected expense is primarily the salary and expenses for this team, and other associated costs (such as vendor costs) in support of the Company achieving the objectives previously discussed. To ensure affordability, the Work Management and Customer Delivery program estimates stable costs through the test year, absorbing increases for

inflation. The historical and projected head count and cost summary for this program is shown in the below table.

**Table 65**

| Work Management and Customer Delivery O&M Headcount & Dollars | | |
|---|---|---|
| **Year (Jan-Dec)** | **Headcount** | **Dollars** |
| 2021 | 285 | $3,211,000 |
| 2022 | 244 | $4,955,000 |
| 2023 | 382 | $3,005,111 |
| 2024 Projected | 331 | $2,320,246 |
| 2025 Projected | 331 | $2,502,146 |
| 2025-2026 Test year | 331 | $2,538,660 |

**Gas Operations Management**

**Q. Please describe the expenses related to the Gas Operations Management O&M Program shown on Exhibit A-89 (JPP-4).**

A. The Gas Operations Management Program includes salaries and expenses for Gas Operations executive level management, Gas Operations support for supply chain and material handling, real estate services that support Gas Operations land ROW, leasing, and Company buildings, and environmental support for contaminated soil testing and clean-up, asbestos assessments and removal, and environmental spills testing and clean-up.

**Table 66**

| Gas Operations Management O&M Projection Breakdown by Activity Type | | |
|---|---|---|
| **Work Type** | **2023 Actual** | **2025-2026 Test year** |
| Gas Operations Management | $834,000 | $1,668,000 |
| **Total Program** | **$834,000** | **$1,668,000** |

**Q. What is the basis for determining the projected $1,668,000 O&M expenses in the test year for this program?**

A. The 2023 actual expense for the Gas Operations Management Program was$834,000. The historical actual amount of program expense is detailed by labor and various non-labor expense components in Exhibit A-89 (JPP-4), page 1, line 3, column b.

The Company's projected test year expense is $1,668,000, as shown on Exhibit A-89 (JPP-4), page 2, line 3, column (j). The projected test year increase from 2023 actual expense is primarily the result of an increase of labor costs to this program. The historical and projected cost summary is shown in the below table:

**Table 67**

| Gas Operations Management O&M Dollars | |
|---|---|
| **Year** | **Dollars** |
| 2016 | $2,195,460 |
| 2017 | $922,551 |
| 2018 | $964,737 |
| 2019 | $1,212,544 |
| 2020 | $1,943,237 |
| 2021 | $1,580,115 |
| 2022 | $2,094,000 |
| 2023 | $834,000 |
| 2024 Projected | $1,700,542 |
| 2025 Projected | $1,643,461 |
| 2025-2026 Test year | $1,668,023 |

**IT PROJECTS**

**Q. Is the Company planning IT projects that support the engineering, asset planning, design, construction, and maintenance of a safe, reliable, and affordable natural gas distribution system for its customers?**

A. Yes. Company witness Stacy H. Baker includes in her direct testimony and exhibits a number of technology projects that are critically important in supporting these gas functions within the Company. The expenditures for these projects are contained within the exhibits sponsored by Ms. Baker. The project providing customer benefits for the areas which I am sponsoring are described below:

- The **Standard Work Plan** project requires $137,388 in O&M in the test year.

  **Description:** The Gas and Electric Resource Planning process is solely reliant on spreadsheets and manual data collection from numerous, disparate sources. It is not only time-consuming but also prone to errors, leading to potential inefficiencies in resource allocation and a lack of detailed, insightful planning. The sole use of spreadsheets makes analyses and what-if scenario development cumbersome. The lack of workplan controls contributes to the completion of pull-ahead work resulting in unnecessary OT and contractor expense. Implementing a centralized planning platform that will interface with existing systems like SAP, DAPP, and EAM Dashboard would transform our planning organization, offering a clear view of planned work and ensuring that executed work is aligned with strategic objectives. In addition, a more integrated system that leverages automation and real-time data analytics would allow for the immediate, what-if scenario planning the business needs to support sound, data-driven decision-making. The tool, alongside necessary process and system enhancements will streamline the workflow and ultimately lead to schedule quality and ensure prudent overtime and contractor usage through reducing the amount of unplanned work breaking into the work management process. A shift to a digital solution that fully aligns resources, work units and feeds the schedule will represent a significant step forward in resource management, aligning with modern best practices.

  **Problem Statement:** The Gas and Electric Resource Planning process is solely reliant on spreadsheets and manual data collection from numerous, disparate sources. It is not only time-consuming but also prone to errors, leading to potential inefficiencies in resource allocation and a lack of detailed, insightful planning. The sole use of spreadsheets makes analyses and what-if scenario development cumbersome. The lack of workplan controls contributes to the

completion of pull-ahead work resulting in unnecessary OT and contractor expense.

**Objectives:** The project will add value by: (1) improving Work Planning Annual Forecast Process: This involves the enhancement of automated inputs, processing, and reporting with a shift towards a more asset-driven prioritization method; (2) converting Monthly Work Plans into Weekly Schedules: Establish a process that seamlessly transforms monthly work plans into executable weekly schedules for easy handoff from planning to scheduling; (3) providing the ability to Run Forecasting and Planning Scenarios: Execute forecasting and planning scenarios and provide comparative analysis; (4) improve system visibility of Work Planned jobs increasing forecast accuracy of downstream processes; and (5) creating multiple dashboards based on the audience of the data providing visibility across all levels of Operations Leadership as well as Supply Chain proactively informing of upcoming workload, potential gaps, opportunities for contingencies if levers are pulled, and clean executable work keeping our workforce fully engaged and productive. This results in improved Field Operations and Customer Satisfaction with delivery commitments and meeting reliability and compliance dates.

**Scope:** The project scope includes the following: (1) developing a system for Work Planning Annual and Monthly forecast with automation; (2) creating the ability to translate the Monthly forecast into an executable Weekly Schedule; (3) creating technology for running Planning Scenarios with ability to compare scenarios for optimized field execution; (4) improving system visibility of Work Planned jobs increasing forecast accuracy of downstream processes (ie. materials); and (5) building Dashboards and reports to provide visibility and help management maintain process control.

**Alternatives:** Alternatives considered: (1) Purchase commercially available system. This option was not selected as a single all-encompassing system does not link the Annual forecasting to execution. Products reviewed included Prometheus. (2) Microsoft Excel based solution. Extending the Microsoft Excel based solution was not selected as it did not provide the level of data integration for controlling a large number of forecasted work items. (3) Development of a system that integrates with our SAP investment. This option was not selected as it does not align to expected value delivery timeline. (4) Purchase a SaaS solution to enable planning and forecasting with integration to our SAP work management system. The fourth alternative was selected because it aligns to the expected value delivery timeline and meets the functional requirements.

**Q. Does this complete your direct testimony?**

A. Yes. The Gas Operations Division is committed to meeting the needs of Consumers Energy's 1.8 million natural gas customers by consistently delivering services safely and

efficiently. The Company's proactive approaches to Gas Operations, Maintenance and Metering, Field Operations, Operations Performance, and Operations Management, ensure that the Company adequately prepares for the future circumstances required to continue serving the needs of customers and the communities in which they live.

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

| | | |
|---|---|---|
| In the matter of the application of<br>**CONSUMERS ENERGY COMPANY**<br>for authority to increase its rates for the<br>distribution of natural gas and for other relief. | )<br>)<br>)<br>)<br>) | Case No. U-21806 |

**REDACTED**

**REBUTTAL TESTIMONY**

**OF**

**JAMES P. PNACEK, JR**

**ON BEHALF OF**

**CONSUMERS ENERGY COMPANY**

May 2025

**Q. Please state your name and business address.**

A. My name is James P. Pnacek, Jr., and my business address is 1945 West Parnall Road, Jackson, Michigan 49201.

**Q. Are you the same James P. Pnacek, Jr. who previously filed direct testimony in this case on behalf of Consumers Energy Company ("Consumers Energy" or the "Company")?**

A. Yes, I am.

**Q. What is the purpose of your rebuttal testimony?**

A. I will discuss the withdrawal of the Company's request for Leak Detection and Repair ("LDAR") deferred expense considerations from my direct testimony. I will address recommendations made by Attorney General witness Sebastian Coppola involving operating and maintenance ("O&M") expenses, specifically related to Gas Line Staking and Locating, Leak Survey and Repair, and Enhanced Infrastructure Replacement Program ("EIRP") Training. I will also address recommendations made by Citizens Utility Board ("CUB") witness Ram Veerapaneni involving adjustments to various Gas Operations O&M expenses including Leak Survey and Repair. I will also address recommendations made by Association of Businesses Advocating Tariff Equity ("ABATE") witness Colin T. Fitzhenry involving Leak Repair and Survey O&M expenses.

**Q. What exhibit are you sponsoring in connection with your rebuttal testimony?**

A. I am sponsoring the following exhibits:

| | |
|---|---|
| Exhibit A-143 (JPP-5) CONF | Staking Bid Analysis; |
| Exhibit A-144 (JPP-6) CONF | Staking Bidder List and Summary; and |
| Exhibit A-145 (JPP-7) | EIRP OM&C Headcount Analysis. |

**Leak Repair and Survey**

**Q. In your direct testimony, you indicated that the Company expected final LDAR rules to be published in January 2025 and to go into effect six months later. Has there been any new development related to the LDAR rules since you filed your direct testimony?**

A. Yes. The Pipeline and Hazardous Materials Safety Administration ("PHMSA") sent the Final Rule for LDAR to the Federal Register in mid-January. However, the Federal Register was unable to formally publish the rule prior to the change in Presidential administrations and the issuance of President Trump's Executive Order: Regulatory Freeze Pending Review. Based on the submitted final rule, which has not yet been published, the general compliance date for O&M activities that require capital and O&M funding is January 1, 2028.

**Q. How has this development impacted the Company's requested relief in this case?**

A. With this new compliance date, the Company will no longer be requesting the Michigan Public Service Commission ("MPSC" or the "Commission") to approve the Company's proposal to defer any test year O&M expense that occurs as a result of the requirements of the final rule that are above the requested funding in this case, as previously requested on page 10, lines 9 through 16, of my direct testimony. The Company agrees with the recommendation of MPSC Staff ("Staff") witness Jacob G. Martus that the LDAR deferral mechanism should not be approved in this current rate case.

**Q. Several parties' witnesses (Attorney General witness Coppola, ABATE witness Fitzhenry, and CUB witness Veerapaneni) recommended that the Commission disallow the $1.3 million of O&M included in your direct testimony for Leak Repair and Survey due to the delay in publishing final LDAR rules. Do you agree with those recommendations?**

A. No. As I state in my direct testimony, the Company plans to eliminate the backlog of known leaks on the system at an accelerated rate as part of its work plan, regardless of the timing of the LDAR rule publication. The Company plans to spend $1,300,000 to address the anticipated leak backlog on the system for the test year in the Leak Survey and Repair program section of my testimony. (See my direct testimony, starting at page 39, line 6, through page 40, line 2.) The Company's decision to reduce the leak backlog was independent of the publication of the LDAR rule. The delay in the LDAR rule publication is not a basis for not including the $1,300,000 for the leak backlog. The Company is accelerating the reduction of leaks on the leak backlog for customer safety, risk reduction, and emissions reduction to serve all of the Company's customers and increase public trust. Staff witness Martus took the correct approach in his testimony when he proposed that the Commission should not approve any deferral for LDAR work beyond the $1.3 million to address the backlog but did not propose any reduction of the money needed to address the backlog. The Commission should reject the recommended reductions proposed by Attorney General witness Coppola, ABATE witness Fitzhenry, and CUB witness Veerapaneni.

**Q. On page 17, lines 3 through 11, of his direct testimony, ABATE witness Fitzhenry presents Table CTF-7 and claims that this data supports his conclusion that the Company does not have a leak backlog. Do you agree with this claim?**

A. No. Mr. Fitzhenry incorrectly concludes that there is no backlog based on his observation that the number of known leaks repaired in 2023 was 27% below the average number of leaks repaired over the last five years. However, the data presented in Table CTF-7 is not useful for determining whether a leak backlog exists. It only shows and can only represent the number of leaks eliminated according to the data in the Company's Department of Transportation ("DOT") report annual filings. The data from Table CTF-7 does not show how many identified leaks were in the backlog before the Company made those repairs. It also does not show the number of new leaks found in each of those years. For example, if more leaks are found in a year than are repaired, then it results in a leak backlog addition. The Company's leak backlog represents any open leak that is currently on the system and has not yet been repaired. It is illogical and incorrect to conclude that a leak backlog does not exist based solely on data showing a decline in the leaks being repaired in Table CTF-7. Contrary to Mr. Fitzhenry's claim, the Company does have a leak backlog, and the Commission should disregard ABATE witness Fitzhenry's incorrect claim to the contrary.

**Q. What is the Company's recent leak backlog?**

A. The Company ended 2023 with a leak backlog of 5,618 leaks and ended 2024 with a leak backlog of 5,480 leaks.

**Q. On page 16, lines 13 through 21, of his direct testimony, CUB witness Veerapaneni recommends that the Commission should base the spending level for Leak Repair and Survey on his 2023 and 2024 average O&M approach. Do you agree with this recommendation?**

A. No. The Company believes that the methodology used by CUB is unreasonable. CUB witness Veerapaneni did not review the reasonableness of the proposed work being undertaken during the test year or the benefits that would be provided to customers.

As I state in my direct testimony starting at page 10, line 5 to line 14, the Company plans to eliminate the backlog of known leaks on the system at an accelerated rate as part of its work plan, regardless of the timing of the LDAR rule publication. The Company plans to spend $1,300,000 to address the anticipated leak backlog on the system for the test year in the Leak Survey and Repair program section of my testimony. The Company is accelerating the reduction of leaks on the leak backlog for customer safety, risk reduction, and emissions reduction to serve all of the Company's customers and increase public trust. The Commission should reject Mr. Veerapaneni's alternative methodology for calculating Leak Repair and Survey expense, which is not based on the Company's actual plans.

**Attorney General Witness Coppola - Gas Staking and Locating O&M Expenses**

**Q. With regard to Staking and Locating expenses, on page 167, lines 14 through 18, of his direct testimony, Attorney General witness Coppola states that typically gas utilities share the cost of locating underground facilities when MISS DIG is requested to locate underground facilities by customers, contractors, and other parties. Do you agree with this statement?**

A. No. The word "typically" implies the Shared Resource Model for the State of Michigan is the standard for gas utilities. This is not an accurate statement. In fact, Consumers Energy has been an outlier among Michigan utilities in recent years for using a Shared Services Model of staking. The Commission has been aware of that for at least three years. In Case No. U-21148, Consumers Energy's 2022 gas rate case, Staff witness David Chislea (Director of the Commission's Gas Safety and Operations Division) testified: "Consumers Energy is the only gas utility in Michigan that attempts to use contractors for initially marking of gas distribution facilities. DTE Gas Company employs locating technicians in its operations group and supplements that team with contractors in the large metropolitan areas during times of peak ticket volumes. To Staff's knowledge, all other gas distribution utilities are utilizing Company technicians for marking facilities." See Mr. Chislea's Direct Testimony in Case No. U-21148, page 17, line 19, through page 18, line 2 (filed April 8, 2022). The Company's transition from the Shared Resource Model to the Dedicated Resource Model moves Consumers Energy in line with other Michigan gas utilities. Mr. Coppola's statement is not accurate, since Consumers Energy, DTE Gas, SEMCO, and MGU all use a dedicated asset-staking model. The Commission should disregard Mr. Coppola's inaccurate claim.

**Q. On page 168, lines 1 through 6, of his direct testimony, Attorney General witness Coppola characterizes the Company-only dedicated staking and locating program in Oakland and Kent Counties as an experimental program to establish whether the incremental benefits justified the incremental cost of a dedicated program. Do you agree with this characterization?**

A. No. The Company never characterized its dedicated staking approach in Oakland and Kent Counties as "experimental" in its testimony in Case Nos. U-21308, U-21490, or the current case. The Company does not view this as an "experimental" program nor did the Company intend to only evaluate the incremental benefits against incremental cost to decide whether it should potentially return to the Shared Resource Model. Mr. Coppola's statement implies that the Company has put a financial value on public safety. That is not accurate. The Company has not put a financial value on public safety. The use of dedicated staking contractors in Oakland and Kent Counties was not a test-case for justifying the Dedicated Staking Model in other parts of the Company's service territory.

**Q. Why did the Company consider transitioning its entire service territory to a Dedicated Staking Model?**

A. I discuss some of the key reasons for moving to a Dedicated Staking Model approach on pages 48 and 49 of my direct testimony. Given the lower level of performance that the Company observed as the result of its prior use of the Shared Resource Model, the Company views the changes to the staking and locating program, originating in Oakland County Gas-Only program, as an initiative to improve public safety by meeting timeliness obligations within Public Act 174 of 2013, improve staking accuracy, and improve excavator communication while pursuing the lowest cost approach that yields the intended

benefits of the staking and locating program. Furthermore, as discussed in my direct testimony and later in my rebuttal testimony, the Dedicated Resource Model is the lowest average unit cost staking option. There is no incremental cost associated with the Dedicated Resource Model when compared to the Shared Resource Model. Continuing with the Shared Resource Model, and not transitioning to the Dedicated Resource Model, would increase the program cost by $3,667,000 for the Company's remaining gas service territory in the test year.

**Q. On page 168, line 7 through line 14, of his direct testimony, Attorney General witness Coppola states that the Company didn't attempt to work with the Shared Resource Model staking and locating contractors to "resolve whatever problems with performance existed and in turn minimize the cost of staking and location." Do you agree with this statement?**

A. No. First, it is incorrect to claim that Consumers Energy did not work with its Shared Resource Model Contractor to resolve problems that arose during the course of its service. The Company conducted quarterly performance reviews with the Shared Resource Model Contractor to review ongoing performance and continuous improvement. These reviews were executed throughout the three-year agreement ending March 2025 with performance issues being identified and communicated to the Shared Resource Model Contractor. Despite these reviews, the Shared Resource Model Contractor did not resolve all of the performance issues identified by the Company during the contract life cycle. Second, it is incorrect to imply that the Company transitioned to a Dedicated Resource Model solely because of unresolved performance issues with its previous Shared Resource Model

Contractor. I have already discussed the variety of valid reasons why the Company transitioned to a Dedicated Resource Model for its staking work.

**Q. On page 168, lines 15 through 19, of his direct testimony, Attorney General witness Coppola states that the Company did not provide any evidence that there was a "serious problem with staking and locating . . . that cannot be resolved in other ways." Do you agree with this statement?**

A. No. Again, Attorney General witness Coppola ignores the numerous other reasons the Company transitioned to a Dedicated Resource Model and continues to falsely claim that the Company's sole reason for making the change was to address "serious problems" with its Shared Resource Model Contractor. As stated on page 50, lines 6 through 9, of my direct testimony, the Company plans to expand the program to "continue to improve public safety, reduce damages, mitigate communication risks with excavators, improve quality, and comply with timeliness requirement within Public Act 174." Additionally, the staking contract with the contractor that the Company uses for its Shared Resource Model expired in the first quarter of 2025. See page 50 of my direct testimony. In anticipation, the Company sent out a request for proposal ("RFP") in the third quarter of 2024 for staking services for the Company's remaining gas service territory that at the time was under the Shared Contractor resource model. The request included options for both shared and dedicated services. The Company only received one bid from a contractor willing to provide services under a Shared Resource Model, but several willing to provide services under a Dedicated Resource Model. The bids yielded an average unit cost for the Dedicated Resource Model that was below the average unit cost of the sole Shared Resource Model Contractor staking model bid. To clarify, the Shared Resource Model Contractor's bid

came in at a significantly higher rate than the previous contracted rate it had with the Company. In other words, the results from the RFP showed that the Company no longer had an option to simply continue its prior Shared Resource Model contract on the same terms or at the same price. The bid from the Shared Resource Model Contractor also came in higher than the bid from the lowest Dedicated Resource Model Contractor. Thus, the statement in my direct testimony remains accurate: the bids yielded an average unit cost for the Dedicated Resource Model Contractor that was below the average unit cost of the Shared Resource Model Contractor was relative to the new higher bid received from the Shared Resource Model Contractor. In short, of the available options after the previous Share Resource Model contract ended, the least expensive option available to the Company was a Dedicated Resource Model contract. As stated in my direct testimony, the analysis shows the Dedicated Contractor model is on average $10.90 less on a per-unit basis when compared to the Shared Contractor model. Continuing with the Shared Contractor model, and not transitioning to the Dedicated Contractor resource model, would increase the program cost by $3,667,000 for the Company's remaining gas service territory in the test year. The decision to expand the use of the Dedicated Resource Model to the remainder of the Company's service territory was based on the improved performance and lower unit cost of the Dedicated Resource Model compared to the Shared Resource Model. In summary, the Dedicated Resource Model aligns the Company to the approach of other gas utilities in the state, improves staking performance, increases public safety, while using the lowest cost option. Continuing with a Shared Resource Model would have meant using a less effective, higher cost option. That is clearly not reasonable. The Commission should disregard the arguments made by Attorney General witness Coppola.

**Q. On page 168, line 20, through page 169, line 4, of his direct testimony, Attorney General witness Coppola argues that the Company's claim that the Dedicated Resource Model is lower cost than the Shared Resource Model is "counter to the historical evidence presented by the Company." Do you agree with this statement?**

A. No. The "historical evidence" that Mr. Coppola is referring to is the contract price under the Company's expired contract for shared-resource staking. That price is no longer available. This project was competitively bid, and the Company has been transparent providing the bid analysis, the actual bids received, and the staking contracts to the Attorney General during discovery. Exhibit A-143 (JPP-5) CONF shows the bid analysis and Exhibit A-144 (JPP-6) CONF shows the contractors requested to bid and those who responded. While previously the Shared Resource Model Contractor unit cost was below the Dedicated Resource Model unit cost, historical pricing is not a guarantee of future pricing. As shown in Exhibit A-143 (JPP-5) CONF, the Shared Resource Model Contractor unit cost is higher than the Dedicated Resource Model Contractor's bid. Although the Company provided the information in Exhibits A-143 (JPP-5) CONF and A-144 (JPP-6) CONF to the Attorney General in discovery, Mr. Coppola ignores this information in his testimony. The Commission should disregard Attorney General witness Coppola's incorrect statements.

**Q. On page 169, line 4 through line 9, of his direct testimony, Attorney General witness Coppola claims that the Company's bidding process cannot be relied upon because the Company has publicly expressed its preference in at least the last two rate cases to move to a Dedicated Resource Model and that contractors have limited their bids based on that preference. Do you agree with this claim?**

A. No. The transition to the Dedicated Resource Model supports public safety and customer value. It was necessary for the Company to disclose its staking and locating approach in the rate case process and all bidding contractors would have access to the same information provided in the cases. This project was competitively bid, and the Company has been transparent providing the bid analysis, the bids received, and the staking contracts to the Attorney General's witness during discovery. The Company indicated in the RFP that it would likely move to the Dedicated Resource Model in 2025 at least for Kalamazoo and Ingham Counties. The Company indicated that the final determination about which counties would transition to a Dedicated Resource Model in this contract would be made after the bid review. At the time of the RFP, the Company was not planning to transition all the counties in its service territory from the Shared Resource Model to the Dedicated Resource Model. As shown on Exhibit A-144 (JPP-6) CONF, 22 suppliers were invited to submit proposals. All bidders were given the opportunity to submit a proposal for: (i) only the Dedicated Resource Model, (ii) only the Shared Resource Model, and/or (iii) both models for all territories excluding Oakland and Kent counties. The Company received five bids. Four of those bids were to supply service for the Dedicated Resource Model only and one bid was to supply service for the Shared Resource Model only. No contractor bid on both approaches. [**BEGIN CONF**] [redacted]

[redacted]

[redacted] [**END CONF**]. The winning staking contractor was determined based on a transparent, competitive bidding process resulting in the selection of the contractor with the lowest overall average unit cost and best value being selected to perform the staking activities to ensure public safety. The Commission should disregard Attorney General witness Coppola's claims to the contrary.

**Q. On page 169, line 12, through page 170, line 2, of his direct testimony, Attorney General witness Coppola recommends that the Commission remove the incremental O&M expense of $11,184,000 included by the Company in the projected test year. Do you agree with this disallowance?**

A. No. For the reasons discussed above, there is no valid reason to reduce the Company's forecasted staking and locating expenses for the test year, which are based on the Company's new contract for staking services. The Company competitively bid the staking activities, performed a bid analysis to evaluate the bids, and selected the lowest overall average unit cost contractor with the best value to perform the staking activities and ensure public safety. Adopting Mr. Coppola's proposal would significantly understate the Company's expected costs for its staking and locating work during the test year. The Commission should reject Mr. Coppola's recommendation to disallow the Staking and Locating incremental O&M.

**<u>Attorney General Witness Coppola – Staking and Locating Deferred Accounting</u>**

**Q. With regard to Staking and Locating Deferred Accounting, on page 194, line 15, through page 195, line 4, of his direct testimony, Attorney General witness Coppola recommends that the Commission reject the staking deferral request the Company proposed in the test year. Do you agree with this recommendation?**

A. No. As I discussed in my direct testimony, there are valid reasons to anticipate more volatility in the number of staking requests during the test year than in prior years, meaning there is greater uncertainty about the accuracy of staking forecasts. With staking requests increasing due to fiber optic and other infrastructure work, the actual staking demand the Company experiences in 2026 could be above the Company's historical staking volume

forecast. The Company has requested the deferral mechanism to cover O&M expenditures associated with expected fluctuations in the volume of staking tickets. The Company based its deferral request mainly on two high-speed internet infrastructure grant programs administered by the Michigan High-Speed Internet Office. The first program is Realizing Opportunities with Broadband Infrastructure Networks ("ROBIN"). According to the State of Michigan's Labor and Economic Opportunities website, the ROBIN program includes $250.6 million to expand high-speed internet service to unserved locations in the state. All program funds must be expended by the end of the 2026 calendar year. The second program is the Broadband Equity, Access, and Deployment Program ("BEAD"). According to the State of Michigan's Labor and Economic Opportunities website, as of 2023, close to 500,000 households are unserved or underserved by high-speed internet infrastructure. BEAD is designed to ensure that every one of Michigan's unserved and underserved homes and businesses can get connected to reliable high-speed internet infrastructure. Approval of Michigan's final list of subgrantees and the locations to be served is anticipated to occur in mid-2025. After final approval, subgrantees will have four years to complete their infrastructure projects and begin delivering service. These two infrastructure projects have the potential to significantly increase staking volumes above forecasted levels. The deferral mechanism benefits both the Company and customers as it allows for refund and recovery without building the unknown cost into rates. Attorney General witness Coppola's recommendation should be rejected by the Commission and the Commission should approve the recommendation made by Staff witness Martus related to the staking and locating deferral.

**Attorney General Witness Coppola - EIRP Training Expenses**

**Q. On page 170, lines 7 through 17, of his direct testimony, Attorney General witness Coppola claims that the Company did not explain the increase in its EIRP training expense. Do you agree with his statements?**

A. No. The reason for the increased training expense is explained on pages 86 and 87 of my direct testimony. The Attorney General simply ignores the testimony, which explains that the EIRP workforce continues to experience employees transferring to other operating departments within the Company and that this movement results in the need for hiring and training to allow for appropriate staffing as the Company implements the Natural Gas Deliver Plan. Mr. Coppola's claim that EIRP is a "mature program" is irrelevant to the issue because, no matter how mature a program is, when employees leave the program for other opportunities within the Company, their replacements will still need to be trained.

**Q. On page 170, lines 15 through 17, of his direct testimony, Attorney General witness Coppola claims that the Company stated in discovery that the increased EIRP expense was needed because "the EIRP workforce continues to grow." Is that an accurate reflection of the Company's discovery response to the Attorney General?**

A. No. Exhibit AG-58, which shows the Company's response to discovery request U21806-AG-CE-0561-Revised, repeats my direct testimony. The response does not state that the EIRP workforce continues to grow, in fact the EIRP workforce has been declining as shown in Exhibit A-145 (JPP-7). The additional training expenses are for new hire and step promotion training caused by movement in the existing workforce. Attorney General witness Coppola's mischaracterization of my testimony and discovery response presents a fallacious strawman argument.

**Q. What is the Company's historical experience related to employee turnover in EIRP?**

A. As shown in Exhibit A-145 (JPP-7), the Gas Construction EIRP Program had a headcount of 495 Operating, Maintenance, and Construction ("OM&C") employees at the end of 2020. From the end of 2020 to the end of 2024, the program lost 116 employees due to headcount reductions but also needed to hire 216 new OM&C employees to replace some of the 379 OM&C employees that remained after the headcount reductions. This means a total of 332 employees left Gas Construction during this time period. As Exhibit A-145 (JPP-7) shows, this is a turnover rate of 76%.

**Q. Given the turnover history and the Company's future plans for EIRP, what additional hiring does the Company plan to do to maintain the appropriate staffing for the program?**

A. As shown on Exhibit A-145 (JPP-7), the Company plans to hire a total of 145 OM&C employees for 2025 and 2026. The hiring is necessary to support the increase in the EIRP work plan miles from 118.1 miles of plastic in 2025 to 136.2 miles of plastic in 2026 as shown in the Exhibit A-138 (KAP-8). As previously stated, the Company needs to expend an incremental $1,656,000 for new-hire and step-promotion training, which is necessary to support the forecasted increase in the EIRP Capital work plan. Attorney General witness Coppola's recommendation to disallow the EIRP Training O&M should be rejected by the Commission. Attorney General witness Coppola has also recommended scaling back the EIRP capital program. The Commission should reject that proposal also. Company witness Pascarello discusses the reasons for rejecting that proposal in her rebuttal testimony.

**CUB Witness Veerapaneni - Test Year Calculation**

**Q. With regard to Gas Operations expenses, on page 16, lines 2 through 10 of his direct testimony, CUB witness Veerapaneni proposes a decrease to the Company's O&M expenses for the Gas Operations Division based on the concept of using a two-year historical average. Do you agree with this approach?**

A. No. The Company believes that the methodology used by CUB is unreasonable. CUB witness Veerapaneni did not review the reasonableness of the proposed work being undertaken during the test year or the benefits that would be provided to customers. The Commission should reject this recommendation.

**Q. With regard to Gas Operations – Other expenses, on page 17, lines 10 through 15, of his direct testimony, CUB witness Veerapaneni proposes an increase to the Company's O&M expense for the Gas Operations-Other Programs based on the concept of using a two-year historical average. Do you agree with this approach?**

A. No. The Company believes that the methodology used by CUB is unreasonable. CUB witness Veerapaneni did not review the reasonableness of the proposed work being undertaken during the test year or the benefits that would be provided to customers. The Commission should reject this recommendation.

**Q. With regard to Gas Storage expenses, on page 18, lines 10 through 19, of his direct testimony, CUB witness Veerapaneni proposes an increase to the Company's O&M expense for Gas Operations - Storage based on the concept of using a two-year historical average. Do you agree with this approach?**

A. No. The Company believes that the methodology used by CUB is unreasonable. CUB witness Veerapaneni did not review the reasonableness of the proposed work being

undertaken during the test year or the benefits that would be provided to customers. The Commission should reject this recommendation.

**Q. On Exhibits CUB-9, line 3, and CUB-11, line 3, CUB witness Veerapaneni proposes a decrease to the Company's O&M expense for the Gas Operations – Field Ops Services program based on the concept of using a two-year historical average. Do you agree with this approach?**

A. No. The Company did not find any discussion on this proposed decrease in CUB witness Veerapaneni's testimony. Reference for the decrease was found only in Exhibits CUB-9 and CUB-11. The Company believes that the methodology used by CUB is unreasonable. CUB witness Veerapaneni did not review the reasonableness of the proposed work during the test year in the O&M Programs or the benefits the O&M Programs would provide to customers. The Commission should reject this recommendation.

**Q. Does this conclude your rebuttal testimony?**

A. Yes.

MR. RUSZKIEWICZ: The Company's next witness is Heather M. Prentice. I probably butchered her name. I apologize. And her direct testimony consisted of a cover page plus 27 pages of prefiled testimony. Company moves to bind in her testimony and also moves to admit the exhibits that she filed, which are labeled as A-90 and A-91. Thank you.

JUDGE VARCHETTI: Are there any objections to the admission of Ms. Prentice's direct testimony or the associated exhibits?

Hearing none, then, the testimony is bound into the record and the exhibits are admitted.

MR. RUSZKIEWICZ: Thank you, Your Honor about.

(Direct Testimony bound in)

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

| | | |
|---|---|---|
| In the matter of the application of<br>**CONSUMERS ENERGY COMPANY**<br>for authority to increase its rates for the<br>distribution of natural gas and for other relief. | )<br>)<br>)<br>)<br>) | Case No. U-21806 |

**DIRECT TESTIMONY**

**OF**

**HEATHER M. PRENTICE**

**ON BEHALF OF**

**CONSUMERS ENERGY COMPANY**

December 2024

**Q. Please state your name and business address.**

A. My name is Heather M. Prentice, and my business address is 1945 West Parnall Road, Jackson, Michigan 49201.

**Q. By whom are you employed?**

A. I am employed by Consumers Energy Company ("Consumers Energy" or the "Company") as the Director of Environmental Compliance, Risk Management & Governance in the Environmental Quality and Sustainability Department.

**Q. How long have you been employed by Consumers Energy?**

A. I have been employed by Consumers Energy since 2008.

**Q. Please describe your educational background and work experience.**

A. I graduated from Ohio Northern University in 1999 with a Bachelor of Science degree in Civil Engineering with an Environmental Option. I am a Registered Professional Engineer in the states of Michigan and Ohio. My environmental investigation and remediation work experience spans 25 years and includes a variety of technical and managerial responsibilities.

After graduating in 1999, I started working for Water Resources & Coastal Engineering, a consulting firm based in Solon, Ohio. As a project engineer, my responsibilities included modification of the facilities planning reports for the City of Cleveland's four major water treatment plants per review comments, analysis of pump performance for various service levels (pressure zones), and estimation of the construction costs for various projects recommended in the plan. I then worked at Camp, Dresser & McKee in its Cleveland, Ohio office. As project engineer, I managed tasks from multiple projects including odor sampling, soil removal, water treatment, and regional storm-water

drainage study projects. Project tasks included developing contract drawings and specifications for the removal of soil stockpiles, interacting with regulatory agencies, preparing construction cost estimates for water treatment equipment, developing public education materials, and hydrologic and hydraulic modeling of interjurisdictional watersheds.

In October 2001, I accepted a position with NTH Consultants, Ltd. ("NTH") in Lansing, Michigan. Throughout my career at NTH, I assumed increasing levels of responsibility from staff engineer to assistant project engineer, and to project engineer on a variety of environmental and civil projects. Projects included due diligence assessments, subsurface explorations, underground storage tank ("UST") removal and closure, and risk-based contaminant exposure evaluations. More specifically, I managed and performed numerous Phase I Environmental Site Assessments ("ESAs") in accordance with American Society for Testing and Materials standards and United States Environmental Protection Agency All Appropriate Inquiry. Based on the Phase I ESA results, I planned and completed Phase II ESAs to characterize and delineate the horizontal and vertical extents of contamination. When appropriate, Baseline Environmental Assessments and due-care plans were prepared in accordance with Michigan Department of Environment, Great Lakes and Energy ("EGLE") guidelines. I have remediated and closed several USTs. I also have extensive construction management experience, including bid specification package development, trade contractor procurement and management, field oversight of construction and demolition projects, and associated documentation and report preparation.

After nine years in consulting, I accepted a position at Consumers Energy in August 2008. I was initially hired to serve as the project engineer and construction manager for

the Little Traverse Bay Environmental Project. In this role, I managed the design and implementation of remedial strategies to address water impacted by cement kiln dust that was entering Little Traverse Bay. Some of the specific responsibilities included managing the project reserve, serving as the day-to-day interface with regulators, maintaining compliance with the final agreement with the State of Michigan, and interfacing with the impacted stakeholders. I also held the overall responsibility for project permitting, the adequacy of engineering design, selection of the contractor(s), project scopes, schedules, and budgets.

In January 2014, I became supervisor of the Risk Management group within the Environmental Compliance, Risk Management & Governance section of the Environmental and Laboratory Services Department. In this role, I became familiar with the status of the 23 Manufactured Gas Plant ("MGP") sites being managed by the Company. I served as the technical resource to the project managers and assisted with aligning the direction of the MGP Program. In January 2015, I became the Director of the Environmental Compliance, Risk Management & Governance section of the Environmental and Laboratory Services Department. The Environmental and Laboratory Services Department is now the Environmental Quality and Sustainability Department.

**Q. What are your responsibilities as Director of Environmental Compliance, Risk Management & Governance?**

A. As Director of Environmental Compliance, Risk Management & Governance, I am responsible for Environmental Compliance Assurance (corporate-wide environmental management system implementation), Environmental Risk Management (assessing and mitigating corporate environmental risks), and Environmental Governance to help ensure

the Company maintains its strong record of excellent environmental stewardship. An integral part of the Environmental Risk Management function includes planning, directing, and controlling the investigation and remediation/risk management at former MGP sites and Comprehensive Environmental Response, Compensation, and Liability Act ("CERCLA" or "Superfund") sites where Consumers Energy is a responsible party. My section also supports the natural gas and electric operating organizations of Consumers Energy regarding the investigation and remediation of environmental contamination. The Risk Management section is also responsible for conducting environmental due diligence assessments for the acquisition, sale, lease, and licensing of Consumers Energy property.

**Q. Have you previously provided testimony before the Michigan Public Service Commission ("MPSC" or the "Commission")?**

A. Yes, I provided testimony in Case Nos. U-17882, U-18124, U-18424, U-20322, U-20650, U-21148, U-21308, and U-21490.

**Q. Are you a member of any professional societies or organizations?**

A. Yes. I represent Consumers Energy on the MGP Consortium. The MGP Consortium is discussed later in my testimony.

**Q. What is the purpose of your direct testimony in this proceeding?**

A. The purpose of my testimony is to: (i) identify the former MGP sites at which Consumers Energy has a present or former ownership interest; (ii) discuss environmental requirements for investigation and remediation by Consumers Energy at these sites; (iii) identify and describe expenditures for environmental response activities at these sites that the Company is seeking approval to recover in this Commission case; and (iv) address the prudency of these expenditures.

**Q. How is your direct testimony organized?**

A. I will discuss the environmental remediation at Consumers Energy's former MGP sites in Sections I through IV of my direct testimony. In Section I of my direct testimony, I will identify and provide information regarding the MGP sites Consumers Energy has identified where it has a present or former ownership interest. In Section II of my direct testimony, I will discuss reasons that Consumers Energy is undertaking environmental investigation and remediation activities at these sites. In Section III of my direct testimony, I will discuss costs and the prudency of the costs. In Section IV of my direct testimony, I will discuss investigation, remediation activities, and overall progress at MGP sites. The accounting and ratemaking treatment for the MGP-related costs which I identify will be discussed by Company witness Matthew J. Foster.

**Q. Are you sponsoring any exhibits?**

A. Yes. I am sponsoring the following exhibits:

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|---|---|
| Exhibit A-90 (HMP-1) | Manufactured Gas Plant Sites Information; and |
| Exhibit A-91 (HMP-2) | MGP Environmental Response Cash Outflows – January 2024 to December 2024 by Phase & Site. |

**Q. Were these exhibits prepared by you or under your supervision?**

A. Yes. These exhibits were prepared by me or under my supervision.

**Q. Please summarize your direct testimony.**

A. Consumers Energy has identified 23 sites that formerly housed MGPs at which it has a present or former ownership interest. Reasonable and typical industry practices during the MGP era resulted in environmental contamination that is unacceptable under current environmental standards and laws. Consumers Energy has incurred, and will continue to incur, costs related to investigation and remediation of MGP sites. Costs related to

investigation and remediation of MGP sites that Consumers Energy is seeking approval of in this case total approximately $997,000 that will be deferred (amortized) over 10 years, and approximately $963,000 in non-deferred (operation and maintenance ("O&M")) dollars in addition to the normal direct management expenses. The split in costs will be discussed further in Section III of my testimony. These costs are reasonable and prudent, as discussed later in my testimony.

**SECTION I – Information on MGP Sites**

**Q. How many MGP sites has Consumers Energy identified where it has a present or former ownership interest?**

A. Consumers Energy has identified 23 sites that formerly housed MGPs at which it has a present or former ownership interest. These sites are listed on Exhibit A-90 (HMP-1). Gas was manufactured from these locations for various periods during the late 1800's until the 1950's when the last MGP was retired. The 23 sites were acquired or built by Consumers Energy between 1917 and 1934 on behalf of customers. Predecessor companies were either acquired by Consumers Energy or no longer exist.

**Q. Please describe Exhibit A-90 (HMP-1).**

A. Exhibit A-90 (HMP-1) provides a summary of site information for each of the 23 former MGP sites, listing: (i) location; (ii) approximate size of the site in acres; (iii) estimated peak plant capacity; (iv) date the plant was acquired or built by Consumers Energy; (v) date natural gas arrived; (vi) date put on standby status; (vii) when the plant was retired; (viii) when the holder (the MGP storage tank) was retired; (ix) the current property owners; (x) the current property use; and (xi) the current site status.

**Q. What was the role of MGPs?**

A. MGPs were formerly an integral part of gas utility service. Prior to the availability of natural gas, gas was manufactured. By the end of the 19th century, manufactured gas was widely used for lighting, heating, and cooking. As natural gas became available, it replaced manufactured gas as a base fuel. Even after natural gas became available, maintaining the ability to manufacture gas on a stand-by basis was viewed as important. At most of Consumers Energy's sites, after natural gas replaced manufactured gas, the plants retained their ability to manufacture gas for use in the event of gas shortages. In addition, the MGP storage tanks, often referred to as holders, were used to store natural gas.

**SECTION II – Need for Environmental Investigation and Remediation**

**Q. Why is Consumers Energy undertaking environmental investigation and remediation activities at former MGP sites?**

A. The levels of environmental awareness have increased significantly since the time when MGPs were operated. During MGP operations, the manufacture of gas resulted in various by-products which are now recognized as being environmentally harmful. Consumers Energy has discovered soil and/or ground/surface water contamination at all 23 of the former MGP sites during remedial investigations. Under current environmental standards, Consumers Energy will incur cleanup costs at all of the sites.

The costs of environmental investigation and remediation with respect to former MGP sites are necessary and ongoing costs of doing business which were not, and could not have been, anticipated during the time MGPs were in operation. Awareness of the environmental risk associated with these by-products did not exist during the MGP era. The costs of investigation and remediation are prudent expenditures that are based on

public policy considerations of protecting the environment and natural resources of the State to help ensure the quality of life that customers desire. These costs are unavoidable and do not arise out of any failure to meet standards at the time the plants were in operation.

**Q. How will site remediation requirements be determined for the former MGP sites in Michigan?**

A. The overall framework for environmental response activities is provided by several statutory enactments. In 1980, Congress enacted the CERCLA, commonly referred to as Superfund, which required potentially responsible parties to investigate and remediate various wastes. In 1982, the Michigan Environmental Response Act ("Act 307") was enacted. In 1990, the State of Michigan passed amendments to Act 307, which established a state program similar to the federal Superfund law, although broader in scope. In 1994, additional amendments were made, and Act 307 was recodified as Part 201 of Act 451 ("Part 201"), the Michigan Natural Resources and Environmental Protection Act, MCL 324.20101 *et seq*. Part 201 provides the primary framework for investigation and remediation of Consumers Energy's former MGP sites. EGLE oversees Michigan's Part 201 Program. As Director of Environmental Compliance, Risk Management & Governance, I am responsible for the Company's primary interface with EGLE on Part 201 issues.

**Q. What EGLE division administers Michigan's Part 201 Program?**

A. EGLE's Remediation and Redevelopment Division administers programs that facilitate the cleanup and redevelopment of sites of environmental contamination in Michigan. This includes the responsibility to oversee Michigan's Part 201 Program. Among other things, it oversees and provides information to support cleanup of contaminated sites by

responsible parties, initiates enforcement action when voluntary compliance cannot be achieved, and recovers State cleanup funds from liable parties. Administrative Rules, Operational Memorandums, and Generic Cleanup Criteria are provided by EGLE. A responsible party is obligated to diligently pursue cleanup at contaminated sites to be compliant.

**Q. Who are responsible parties under Part 201?**

A. Under Part 201, those liable for response activity costs include: (i) the owner or operator of a facility, if the owner or operator is responsible for an activity causing a release or threat of release; and (ii) the owner or operator of a facility at the time of disposal of a hazardous substance, if the owner or operator is responsible for an activity causing a release or threat of release. Under certain circumstances, others can also be liable for response activity costs.

A party may be liable under Part 201 even though the act causing environmental contamination was lawful and reasonable at the time. Any potentially responsible party may be held liable for the entire cost of investigation and remediation of a site. Part 201 states that it applies regardless of whether the release or threat of release of a hazardous substance occurred before or after the effective date of Part 201.

**Q. What is a utility's responsibility at a former MGP site that it owned or operated?**

A. Part 201 requires that when a liable owner or operator of a facility obtains information that there may be a release of a hazardous substance at a facility for which they are liable, such owner or operator must take appropriate action, including confirming the existence of the release, determining the nature and extent of the release, reporting the release to EGLE if there was a reportable quantity released, and immediately taking steps to stop any

continuing release. Part 201 contains affirmative obligations to avoid exacerbation of any existing contamination. The liable owner or operator must "diligently pursue" environmental response activities, including investigation and remediation, and ultimately address all contaminants associated with the site. Consumers Energy has been the owner or operator for all the former MGP sites listed on Exhibit A-90 (HMP-1) and currently owns all or portions of most of the former MGP sites listed.

EGLE has responsibility to oversee and coordinate all activities required under Part 201. EGLE is authorized by Part 201 to request or order remediation by one or more responsible parties or to undertake response activities and to recover costs incurred from responsible parties later. Each year, EGLE publishes a list of Michigan Sites of Environmental Contamination ("Part 201 Inventory of Facilities"). There are currently about 17,916 sites of environmental contamination listed on the Part 201 Inventory of Facilities. All 23 Consumers Energy former MGP sites are on the Part 201 Inventory of Facilities.

**Q. Has Consumers Energy identified any former MGP owners or any predecessor or successor companies of such owners for the 23 sites at which Consumers Energy has a present or former ownership interest?**

A. No. A prior search for former MGP owners or any predecessors or successor companies of such owners for the 23 sites did not find any in existence today. Hence, no other potentially responsible parties have been identified.

**Q. Does a site have to be listed on the Part 201 list in order for an owner or operator to be obligated to undertake environmental response activities or to incur response costs?**

A. No. EGLE is authorized to require that environmental response activities be undertaken by a responsible party even if the site is not listed on the Part 201 list. In addition, discovery of contamination related to MGPs at or near a former MGP site can require an owner or operator to undertake response activities.

**Q. What is Consumers Energy's strategy for the management of the former MGP sites?**

A. Consumers Energy's strategy is to minimize the impact from the former MGP sites on human health and safety, as well as to minimize any damage to the surrounding natural resources, in the most cost-effective way possible. The strategy for the management of the former MGP sites is based on the environmental risk that these sites pose to human health, safety, and damage to natural resources. Consumers Energy routinely assesses the environmental exposure and/or exacerbation risks at each site based on changing conditions and new information. Based on the risk assessment, response activities are prioritized, developed, designed, and implemented.

The environmental response strategy will be determined based upon the land uses and zoning at individual facilities, the environmental media involved, and the relevant exposure pathways. The key elements of an exposure pathway are a source or release of a hazardous substance, an exposure point, an exposure route, and a transport mechanism. In developing an environmental response strategy at a particular site, the Company develops a plan to address contamination in all environmental media, including but not limited to: (i) contaminated groundwater; (ii) contaminated soils; (iii) contaminated sediments; and

(iv) vapor intrusion. Based on the media impacted and the nature of contaminant(s), remediation strategies may vary including removal, recovery, containment/barrier technologies, monitored natural attenuation, etc. Once exposure risks for all contaminants in all applicable media for all exposure scenarios are mitigated, the site may be eligible for No Further Action ("NFA").

**Q. Is it possible under current regulations to obtain total closure status for an environmentally contaminated former MGP site?**

A. No. Part 201 of the Natural Resources and Environmental Protection Act, 1994 Public Act 451, was revised in 2010 by adding a regulatory mechanism that allowed for NFA at a contaminated site if certain conditions are met. However, NFA does not mean there is a total closure. Rather, NFA is a regulatory status that allows the site to maintain a "negotiated status quo," that requires no or minimal ongoing remedial actions. It is the responsibility of the owner/operator to maintain the agreed upon conditions of the NFA agreement such as due care, groundwater monitoring, and O&M of control technologies. If any of the conditions are not maintained, or there is a change in conditions, the NFA status becomes invalid. While NFAs acknowledge remedial actions performed and what exposures/risks are still present at the sites, approvals of these actions do not eliminate present or future liabilities or close the site.

**Q. Who is financially responsible if the negotiated status is not maintained and work needs to be performed?**

A. Typically, the party that commits the noncompliance will ultimately be financially responsible.

**Q. Is Consumers Energy looking into the possibility of obtaining NFA status at former MGP sites?**

A. Yes. Consumers Energy is actively pursuing NFA at several former MGP sites. It should be noted that the Company does not consider a site eligible to pursue NFA status unless contamination in all environmental media is addressed. Consumers Energy submitted and obtained NFA status for the following former MGP sites:

- Ionia – 2013
- Grand Ledge (site proper) – 2016
- Marshall – 2019
- Mt. Clemens (site proper) – 2021
- Royal Oak – 2021
- Alpena – 2021
- Bay City (site proper) - 2022
- St. Johns (site proper) – 2023
- Manistee (Operational Site) – 2023
- Hastings (site proper) – 2024
- Bay City (off-site) – 2024

An NFA was submitted for the Sault Saint Marie MGP site but was ultimately withdrawn due to lack of property owner signature on the necessary restrictive covenant. A Certificate of Completion was obtained for this site in 2021.

Consumers Energy has also initiated discussions with EGLE regarding several MGP sites that potentially may qualify for NFA status. This is discussed later in my testimony. Due to the complexity of the remediation that needs to be addressed and current

status of remediation, it would not be efficient at present to seek NFA status at all of the sites. In some cases, it may be more practical to obtain a Certificate of Completion (described below) due to site restrictions/liability concerns.

**Q. Does NFA mean that there will be no additional costs on these sites?**

A. No. There will be costs associated with these projects even after they achieve NFA status. These costs may include routine sampling, preparing and submitting reports, some O&M tasks, due care, etc. These long-term, post-NFA costs may be significant.

**Q. What is a Certificate of Completion?**

A. A Certificate of Completion is a written response provided by EGLE that a response activity has been completed in accordance with the applicable requirements of Part 201 and is approved by EGLE.

**Q. What are the benefits of a Certificate of Completion?**

A. A Certificate of Completion provides EGLE concurrence that response activities were performed at a site as proposed. However, there are no requirements for either Post Closure Agreements or financial assurance with a Certificate of Completion.

**Q. Has the Company received any Certificates of Completion?**

A. Yes. The Company received a Certificate of Completion from EGLE in July 2019 for the Sediment Response Action project at the Flint East MGP, and for the Sault Saint Marie site as discussed earlier. The Certificate of Completion for the Manistee River Sediment work was deemed administratively approved in 2022.

**Q. What is a Post Closure Agreement?**

A. It is an agreement that may be required by EGLE based on activities needed following NFA approval. The agreement is between EGLE and the submitting entity. It contains terms regarding future liabilities and potential reopeners of the NFA document.

**SECTION III – Costs and Prudence**

**Q. What levels of expenditures are attributable to environmental response activities at the 23 former MGP sites?**

A. The level of environmental response expenditures for the period January 2024 through December 2024 totals approximately $997,000 in deferred (amortized) dollars, and $963,000 in non-deferred dollars for the period of October 1, 2025 through September 30, 2026.

**Q. Do these amounts include Consumers Energy's Project Management ("PM") costs?**

A. No. As recommended by the Commission Staff ("Staff") in Case No. U-14547, the Company has excluded PM and associated costs from the MGP Environmental Response Cash Outflows.

**Q. Please describe what types of costs were excluded from the MGP Environmental Response Cash Outflows.**

A. The types of costs excluded are costs of Consumers Energy employees and associated expenses such as Labor, Lab Services, Fleet, Real Estate, business expenses, and computer charges. Those costs are included as O&M expense. In addition, Consumers Energy has excluded professional organization membership costs and lawn maintenance costs from the MGP Environmental Response Cash Outflows shown on Exhibit A-91 (HMP-2).

Membership fee expenditures and lawn care expenditures are included instead as O&M expenditures.

**Q. Do the MGP Environmental Response Cash Outflows you are presenting in this rate case include professional membership fees?**

A. No. As mentioned earlier, professional membership fees, specific to MGP remediation operation, are not included in the MGP Environmental Response Cash Outflows shown on Exhibit A-91 (HMP-2). However, professional membership costs are included in the MGP PM and Associated Costs included in the O&M portion of the rate case. The two specific professional memberships are the Utility Solid Waste Advisory Group ("USWAG") and MGP Consortium.

Membership in the USWAG is directly related to helping Consumers Energy evaluate environmental investigation and remediation response activities and to identify the most cost-effective MGP investigation and remediation measures that are protective of human health and the environment. The USWAG provides a technical resource for management of waste streams from the remediation of MGP sites allowing for protection of natural resources while minimizing unnecessary costs.

The MGP Consortium includes members from various utility companies in the nation who are currently managing MGP sites as part of their liability management. The MGP Consortium is designed to discuss and share knowledge or project experience between owners/operators of former MGP sites. Membership in the MGP Consortium has facilitated discussions about general MGP PM, remediation technology evaluation, remediation technology application, lessons learned, public relations, public policy trends, and vendor evaluations. These memberships have helped Consumers Energy in its

evaluation of technical, regulatory, legislative, and policy issues related to the investigation and remediation of former MGP sites.

**Q. Why have dollars been separated as non-deferred?**

A. In Case No. U-20650, the Company agreed in rebuttal testimony to include routine monitoring and reporting and regulatory/legal requirements of Post Closure Agreements or other mechanisms after receipt of NFA, Remedial Action Plan, or Certificate of Completion approval as non-deferred (O&M) expenditures. This change began with the test year for Case No. U-21308. These costs are in addition to the direct management or other O&M costs previously discussed.

**Q. What is the amount of the non-deferred MGP expenditures?**

A. The additional amount of non-deferred MGP expenditures is $963,000. These expenses are covered in Company witness Matthew J. Foster's Exhibit A-47 (MJF-5).

**Q. Were MGP environmental response activity costs incurred prior to January 2024?**

A. Yes. Costs for environmental response activities for periods prior to January 2024 were reviewed and audited by Staff in Case No. U-21490 and earlier cases; therefore, these costs have not been included on Exhibit A-91 (HMP-2) in the current case.

**Q. At how many of the sites will Consumers Energy incur deferred (amortized) costs during the period January 2024 through December 2024?**

A. Costs will be incurred at 12 sites.

**Q. Why were deferred costs not incurred at all of the 23 MGP sites?**

A. As the sites reach NFA status or point of minimal activity, the Company does not necessarily use consultants for the remaining activities. The Company will use internal staff to complete the necessary obligations and reporting to reduce the program costs.

**Q. Please explain Exhibit A-91 (HMP-2).**

A. Exhibit A-91 (HMP-2) shows the cash outflows for environmental investigation and remediation during the period January 2024 through December 2024 for each MGP site. Costs are shown by phase and in total for all 23 MGP sites.

**Q. How were these costs developed?**

A. Costs shown on Exhibit A-91 (HMP-2) include projected costs. Costs for January through December 2024 are projected costs based on the work scope developed for the sites and the long-term strategy.

**Q. How did you determine the costs for activities that have not yet occurred?**

A. The cost for each activity is based upon the strategy identified to move the site toward NFA/Certificate(s) of Completion. The strategies have been developed based on past experience at Consumers Energy sites and other sites, overall knowledge, site background, site use, site investigations, remedial investigations, and feasibility study evaluations. Based on all this information and data, we determine, with assistance from the consultants involved with each of these sites, how to move sites forward in the most prudent way possible while maintaining compliance with EGLE regulations and requirements.

**Q. Why are the costs incurred different at different sites?**

A. Environmental response costs are influenced by a number of site-specific factors. Costs can vary significantly depending on: (i) the nature and extent of contamination; (ii) size of the site; (iii) geology of the site; (iv) presence of surface water and depth of groundwater; (v) present and future use of the site; and (vi) types of remedial action. The costs on the exhibit differ due to site-specific factors.

**Q. What MGP environmental expenditures are you seeking approval for in this case?**

A. Consumers Energy is seeking approval in the current case for deferred (amortized) MGP environmental response expenditures from January 2024 through December 2024. The Company is also seeking approval of non-deferred (O&M) recovery of MGP expenditures for the test year that covers November 1, 2025 through October 31, 2026.

**Q. Are the expenditures that Consumers Energy is seeking recovery for in this case reasonable and prudent?**

A. Yes. The need for environmental investigation, remediation, and the parameters for cleanup are mandated and defined by the state and federal government. The costs of investigation and remediation are not based on any imprudence, but upon public policy considerations of protecting the environment and natural resources of the State on behalf of the customers the Company serves. MGP site investigation and remediation costs are legitimate and necessary costs of doing business. The costs incurred were costs for activities that are necessary under current environmental regulations and overseen by EGLE. The need for incurring such costs is based upon current environmental awareness, not any fault on the part of the operator of the former MGP facilities.

**Q. Does the Company coordinate site activities with EGLE?**

A. Consumers Energy has taken a proactive role with EGLE. By taking a proactive role, Consumers Energy has had a better opportunity to participate in decisions involving investigation and remedial actions than if EGLE were to order remediation or to undertake remediation itself. Consumers Energy has undertaken response activities in an efficient manner to minimize costs consistent with health and safety considerations. Consumers Energy has sought approval from EGLE of the most cost-effective remediation, which is

protective of human health and the environment, as allowed by law. The expenditures which Consumers Energy is seeking to recover in this case are reasonable and prudent.

**Q. Does the Company use competitive bidding as a means of controlling costs?**

A. Yes. Current Company policies require competitive bidding for purchases of materials and/or services initially over $100,000, except for emergencies or where only one vendor can supply the goods or services. For smaller scale response activities, such as drilling and small disposal activities, the site consultant handles the initial bidding and ensures the contracted costs are reasonable. For larger activities, the Company competitively bids the project. If competitive bids are not sought, the Company documents reasons why the competitive bidding process was not used. During the competitive bidding process, the qualifications of each contractor and subcontractor are reviewed to determine if they have the resources and expertise to complete the tasks on which they are bidding. The Company also evaluates contracting strategies (e.g. time and materials, lump sum, not to exceed, etc.) to determine which will provide the most value and reduce risks during the projects.

**Q. Please describe how the consultants used were selected.**

A. The initial consultants for each site were selected using a bidding process. Consultants who were interested bid for each MGP site separately. As part of the competitive bidding process, the qualifications of each consultant were reviewed to determine if they had the resources and expertise to complete the projects on which they were bidding. The Company currently has five consultants for the MGP sites. Using the same consultant for more than one site increases efficiency and improves consistency. Limiting the consultants to fewer than all sites helps assure that they will be able to complete the work in a timely fashion.

**Q. Please discuss Environmental Response Cash Outflows at the MGP sites.**

A. The majority of the Environmental Response Cash Outflows shown on Exhibit A-91 (HMP-2) are for remedial actions. Remedial action costs were incurred at 6 of the 23 sites. The remedial action costs incurred include collection of data supporting remedial action and response activities such as: (i) source-area impacted soil removal; (ii) operation of existing in-site remediation systems; (iii) groundwater monitoring; (iv) treatability studies; and (v) other activities intended to resolve containment issues. The environmental response costs also include activities related to Remedial Investigations, Feasibility Studies, and NFA. The NFA phase tasks included EGLE negotiations, preparation of NFA reports, property surveys, and recording use restrictions, etc. O&M tasks included monitoring, operation, maintenance, due care, and reporting obligations. Response activities are discussed in more detail later in my testimony.

**SECTION IV – Response Actions**

**Q. What types of environmental response activities may be required at a former MGP site?**

A. The sequence, timing, and magnitude of response activities vary from site to site depending upon the size of the site, the degree of environmental contamination, current and potential future land use, the degree of enforcement discretion exercised by EGLE, the media impacted, and other site-specific factors. However, the usual sequence of environmental response activities which would typically be undertaken at a former MGP site would be:

1. Site Investigation;
2. Remedial Investigation;
3. Interim Response Activities;
4. Feasibility Study;
5. Remedial Action;
6. NFA; and

7. O&M.

**Q. Please briefly describe each of these activities.**

A. **Site Investigation:** A Site Investigation involves research of site-related information such as available historical records, past and current site uses, topographical maps, engineering drawings, and a review of potential sources of environmental contamination. A site visit is also usually done during a Site Investigation to relate the information collected by the records search to current site conditions and to conduct a visual inspection for any obvious signs of MGP contamination.

**Remedial Investigation:** The purpose of a Remedial Investigation is to define the nature and extent of contamination at a site. Consumers Energy worked with EGLE to reach a common understanding on facility prioritization criteria as it relates to risk assessment and exposure pathways. In addition, Consumers Energy sought input, review, and concurrence from EGLE on major remedial investigation work plans. This collaborative approach allowed Consumers Energy to be better responsive to EGLE concerns and issues in developing and implementing work plans.

The Remedial Investigation includes the collection and analysis of samples of surface soils, subsurface soils, groundwater, and/or surface water. Limited field screening measurements of soil, gas, and air samples may also be conducted. These samples are analyzed for chemicals of concern that are typical of MGP by-products and wastes. Remedial Investigations typically generate solid and liquid waste, called Investigation Derived Waste, that must be disposed per state and federal regulations.

**Interim Response Activities:** Interim Response Activities may be required if the results of the Remedial Investigation or other information indicates a need to abate a threat to human health or to the environment on an interim basis while further investigation

occurs. Examples of the types of Interim Response Activities which may occur for contaminated soils include erecting a fence, installing drainage controls and stabilization, capping, removal, and treatment or disposal of the grossly contaminated soils to eliminate direct-contact hazards and to prevent further migration. Free phase product recovery is also considered as an Interim Response Activity. Interim Response Activities can also generate solid and liquid waste that must be disposed per state and federal regulations.

**Feasibility Study:** The purpose of the Feasibility Study is to develop, evaluate, and select which of several remedial action alternatives, including no action, may be appropriate. The Feasibility Study involves identifying appropriate remedial technologies, determining the applicability of the technologies to a specific site, evaluating the implementability and total cost of operations, and developing a cost benefit analysis.

**Remedial Action:** Remedial Action includes, but is not limited to, cleanup, removal, containment, isolation, destruction, or treatment of a hazardous substance released or threatened to be released. Some remedial actions may require operation of active remediation systems, which require significant ongoing activities along with performance monitoring. Remedial actions may generate significant solid and liquid waste that must be disposed per state and federal regulations.

**NFA:** Once Remedial Action is complete, and the applicable cleanup criteria are achieved, then the project may be eligible to seek NFA status. The NFA is usually associated with some land and resource use restrictions along with long-term monitoring and/or due-care obligations. As discussed earlier in my testimony, it is not possible under current regulations to obtain total closure status for the former MGP sites. The NFA activities may include NFA report preparation, negotiations with EGLE and other

stakeholders, developing and recording site surveys, restrictive covenants, etc. Preparation of Certificate(s) of Completion will also be included as NFA activities.

**O&M:** Activities performed as O&M may include routine monitoring data collection, due-care activities, system operation and maintenance, and associated reporting. The O&M activities may be required indefinitely.

**Q. What are some examples of environmental response activities that have either been completed during the January 2024 through October 2024 timeframe or are currently underway?**

A. Examples of projects that have been completed or are underway include the following:

- Bay City MGP site – Submitted a NFA to EGLE for MGP area south of 9th Street.
- Charlotte MGP site – NFA drafting was initiated.
- Flint Court MGP site – Annual groundwater sampling was performed. Continued quarterly vapor intrusion sampling of the former by-products building.
- Flint East MGP site – Annual groundwater sampling was performed. Conducted inspections and bathymetry evaluations within sediment cap reach. Completed the vapor intrusion assessment near the Rec Center building with no issues identified. Continued to provide review comments on the dam removal design as it impacts the river sediment removal work that was performed in 2017. Performed cap inspections during work on dam.
- Kalamazoo MGP site – Collected one additional round of groundwater samples from new monitoring wells as well as certain key monitoring wells to have current data in advance of preparing the NFA document. Collected an additional round of sub-slab and indoor air samples to evaluate the vapor intrusion pathway. Prepared the NFA document and associated institutional control documents (restrictive covenants and public highway institutional control).
- Jackson MGP site – Began preparing a Comprehensive Project Summary Report.
- Manistee MGP site (ongoing) –Performed quarterly groundwater sampling at the former relief holder site. Expanded the air sparge system on the former

relief holder site. Performed a cyanide evaluation based on observations during groundwater sampling events.

- Owosso – Annual groundwater sampling was performed. Purchased three residential homes impacted by the former MGP. Performed engineering for demolition of the residential homes. Demolition of the homes occurred in October 2024.

- Plymouth MGP site – Annual sampling was performed at the site. Performed delineation work in front of Messina garage to evaluate potential source controls. Also, replaced monitoring wells as requested by EGLE.

Additionally, investigations, routine monitoring, reporting, NFA activities, and O&M activities were also conducted.

**Q. Does the Company need a formal approval by EGLE to implement response activities?**

A. No. A formal approval is not required to implement response activities. However, Consumers Energy has taken a proactive role with EGLE to provide an opportunity to collaborate with EGLE regarding decisions involving investigation and remedial actions. This approach helps minimize the possibility of EGLE issuing a remediation order or undertaking the remediation itself at Consumers Energy's expense. We believe that our continuous involvement with EGLE and the collaborative approach results in cost-effective remediation that is protective of human health and the environment as required by law. This collaborative approach is carried out both through formal and informal means.

**Q. Can you summarize any recent approvals that Consumers Energy has received from EGLE?**

A. Based on the activities completed from January 1 through October 31, 2024, the Hastings and Bay City (off-site) NFAs were approved by EGLE.

**Q. How does the Company respond to EGLE requests for inclusion of additional parameters in testing or any other requests at a site?**

A. The Company has highly trained remediation experts that will review the request, evaluate the value provided by the request, and discuss this evaluation with EGLE. Inclusion of additional parameters or other requests suggested by EGLE can significantly increase costs. In addition, practical and technical limitations must be considered. If these are not typical for the type of remedial action underway, the Company will attempt to determine if there is an alternative or more cost-effective way to address EGLE's concerns.

As mentioned earlier in my testimony, Consumers Energy has taken a proactive role with EGLE to provide an opportunity to collaborate with EGLE regarding decisions involving investigation and remedial actions. This approach helps minimize the possibility of EGLE issuing a remediation order or undertaking the remediation itself at the Company's expense. Consumers Energy seeks approval from EGLE of the most cost-effective remediation that is protective of human health and the environment as required by law.

**Q. Please describe soil and/or groundwater remediation systems in operation.**

A. Currently, there is one active groundwater remediation system at the MGP sites. The Cross Street site remediation system consists of a groundwater air sparge system, installed in 2011. This system was deactivated in 2019 to evaluate groundwater conditions and allow for in-situ soil stabilization of the impacted soils near the former holder location. The system remained off until the spring of 2022 when groundwater concentrations began to rebound. The system was expanded in 2024 to address the concentrations in wells outside

of the original capture area of the system. It is currently anticipated that the system will need to operate for two years to address the concentrations present at the site.

**Q. Does the Company have any inactive soil and/or groundwater remediation systems?**

A. Yes. The multiphase system that consists of a Light Non-Aqueous Phase Liquid recovery system, a groundwater pump and treatment system, and a Soil Vapor Extraction and treatment system at the Jackson MGP site has been inactive since April 2016. The system is slated for decommissioning in 2025.

**Q. Were there any MGP property ownership changes in the time period covered by this filing?**

A. No.

**Q. Are the MGP costs described in your testimony reasonable and prudent?**

A. Yes, they are. They are reasonable and prudent costs of doing business.

**Q. Does this conclude your direct testimony?**

A. Yes.

MR. RUSZKIEWICZ: The Company's next witness is Heather L. Rayl. And based on stipulation of the parties, the Company moves to bind in the testimony of Ms. Rayl, which consists of direct testimony of a cover page plus 24 pages of prefiled testimony, and rebuttal testimony that is a cover page and 6 pages of prefiled testimony.

The Company also moves to admit exhibits of Ms. Rayl, and I'll go through that list now, starting with A-1 Schedule A-1, A-1 Schedule A-2, A-2 Schedule B-1, A-2 Schedule B-2, A-2 Schedule B-3, A-2 Schedule B-4, A-2 Schedule B-5, A-2 Schedule B-6, A-3 Schedule C-1, A-3 Schedule C-2, A-3 Schedule C-3, A-3 Schedule C-4, A-3 Schedule C-5, A-3 Schedule C-5.1, A-3 Schedule C-6, A-3 Schedule C-7, A-3 Schedule C-8, A-3 Schedule C-9, A-3 Schedule C-10, A-3 Schedule C-11, A-3 Schedule C-12, A-3 Schedule C-13, A-4 Schedule D-1, A-4 Schedule D-2, A-4 Schedule D-3, A-4 Schedule D-4, A-4 Schedule D-5, A-11 Schedule A-1, A-11 Schedule A-2, A-11 Schedule A-3, A-12 Schedule B-1, A-12 Schedule B-2, A-12 Schedule B-3, A-12 Schedule B-4, A-12 Schedule B-5, A-13 Schedule -- Schedule C-1, excuse me, A-13 Schedule C-1-1, A-13 Schedule C-2, A-13 Schedule C-3, A-13 Schedule C-4, A-13 Schedule C-5, A-13 Schedule C-5.1, A-13 Schedule C-6, A-13 Schedule C-7, A-13 Schedule C-8, A-13 Schedule C-9,

A-13 Schedule C -- excuse me, A-13 Schedule C-10, A-13 Schedule C-11, A-13 Schedule C-12, A-13 Schedule C-13, A-92, A-146 through A-155, and I believe that's it for the witness. Thank you.

JUDGE VARCHETTI: Okay. Are there any objections to the binding in of the direct and rebuttal testimony of Ms. Rayl or any of the numerous associated exhibits?

I am hearing none, so her direct and revised -- direct and rebuttal testimony are bound into the record and the associated exhibits are admitted.

MR. RUSZKIEWICZ: Thank you, Your Honor.

(Direct and Rebuttal Testimony bound in)

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

| | | |
|---|---|---|
| In the matter of the application of **CONSUMERS ENERGY COMPANY** for authority to increase its rates for the distribution of natural gas and for other relief. | ) ) ) ) ) | Case No. U-21806 |

**DIRECT TESTIMONY**

**OF**

**HEATHER L. RAYL**

**ON BEHALF OF**

**CONSUMERS ENERGY COMPANY**

December 2024

**Q. Please state your name and business address.**

A. My name is Heather L. Rayl, and my business address is One Energy Plaza, Jackson, Michigan 49201.

**Q. By whom are you employed and in what capacity?**

A. I am employed by Consumers Energy Company ("Consumers Energy" or the "Company") as a Senior Rates Analyst in the Revenue Requirements Section of the Rates and Regulation Department.

**Q. Please state your educational background.**

A. I received both a Bachelor of Arts and a Master of Business Administration degree from Michigan State University in 1993. I am also a Certified Public Accountant registered in the state of Michigan.

**Q. Please describe your business experience.**

A. After receiving my degrees in 1993, I have held various positions in audit, accounting, and finance with a focus in financial statement preparation and analysis, general ledger analysis, and preparation and analysis of statutory annual reports.

In 2004, I started my career at Consumers Energy as a Senior Analyst in the Accounting Research and External Financial Reporting Department. My responsibilities included the research and documentation of numerous technical accounting topics for departmental clients, including United States Generally Accepted Accounting Principles issues, United States Securities and Exchange Commission issues, utility/regulatory accounting issues. I was also responsible for the preparation and documentation of financial statement disclosures in the Company's Forms 10-K and 10-Q, with a focus in regulatory matters.

In 2013, I transferred to Consumers Energy's Rates and Regulation Department. During my tenure, I have held positions in Revenue Requirements and Rate Design as a Senior Rates Analyst.

**Q. What are your job responsibilities?**

A. I am responsible for conducting analyses related to the Company's revenue requirements and developing testimony and exhibits in support of proposals in regulatory proceedings before the Michigan Public Service Commission ("MPSC" or the "Commission").

**Q. Have you previously testified in any proceedings before the Commission?**

A. Yes. I have filed testimony in Gas Rate Case Nos. U-18124, U-18424, U-21148, U-21308, and U-21490; Gas Cost Recovery ("GCR") Plan Case Nos. U-17334, U-17693, U-17943, U-18151, U-21269, and U-21437; GCR Reconciliation Case Nos. U-16924-R, U-17133-R, U-17334-R, and U-17693-R; Gas Revenue Decoupling Case No. U-18367; Renewable Energy Plan Case No. U-18231; and Investment Recovery Mechanism Reconciliation Case No. U-20893.

**Q. What is the purpose of your direct testimony in this proceeding?**

A. The purpose of my direct testimony is to: (i) identify and support the Part I exhibits required by the Commission's Order in Case No. U-18238 ("Filing Requirements") and (ii) present Consumers Energy's revenue requirement calculation for the projected test year.

**Q. How are the following sections of your direct testimony organized?**

A. My direct testimony is divided into four sections:

Section I: Historical Year

Section II: Projected Test Year

Section III: Rate Impact from the Sale of the Riverside Storage Field

Section IV: Accounting Treatment for MAOP Retesting Costs to Comply with New Federal Safety Standards

**Q. Please describe the revenue requirements determination.**

A. In compliance with the Filing Requirements, my direct testimony presents the revenue requirement for the historical year, explains the development of the revenue requirement for the projected test year, and reconciles the historical and projected test years. The Company demonstrates in this instant case that it requires a rate increase to its gas tariffs to earn a just and reasonable return.

**Q. Are you sponsoring any exhibits?**

A. Yes. I am sponsoring the historical year exhibits identified in Section I of my direct testimony and the projected test year exhibits identified in Section II of my direct testimony.

**Q. Were these exhibits prepared by you or under your direction and supervision?**

A. Yes.

## I. HISTORICAL YEAR

**Q. What is the historical year used in your exhibits and supporting direct testimony?**

A. Calendar year 2023 is the historical year in the instant case.

**Q. Please identify the exhibits that you are sponsoring to comply with the Commission's Filing Requirements for the historical year.**

A. I am sponsoring the following exhibits to satisfy the Commission's historical year Filing Requirements:

| | | |
|---|---|---|
| Exhibit A-1 (HLR-1) | Schedule A-1 | Revenue Deficiency (Sufficiency) for the Historical Year Ended December 31, 2023; |
| Exhibit A-1 (HLR-2) | Schedule A-2 | Financial Metrics - Gas Results Only; |

| | | |
|---|---|---|
| Exhibit A-2 (HLR-3) | Schedule B-1 | Rate Base for the Historical Year Ended December 31, 2023; |
| Exhibit A-2 (HLR-4) | Schedule B-2 | Total Utility Plant for the Historical Year Ended December 31, 2023; |
| Exhibit A-2 (HLR-5) | Schedule B-3 | Depreciation Reserve and Other Deductions for the Historical Year Ended December 31, 2023; |
| Exhibit A-2 (HLR-6) | Schedule B-4 | Working Capital for the Historical Year Ended December 31, 2023; |
| Exhibit A-2 (HLR-7) | Schedule B-5 | 13-Month Average Balance Sheet for the Historical Year Ended December 31, 2023; |
| Exhibit A-2 (HLR-8) | Schedule B-6 | Point-in-Time Balance Sheet for the Historical Year Ended December 31, 2023; |
| Exhibit A-3 (HLR-9) | Schedule C-1 | Adjusted Net Operating Income for the Historical Year Ended December 31, 2023; |
| Exhibit A-3 (HLR-10) | Schedule C-2 | Revenue Conversion Factor for the Historical Year Ended December 31, 2023; |
| Exhibit A-3 (HLR-11) | Schedule C-3 | Operating Revenue for the Historical Year Ended December 31, 2023; |
| Exhibit A-3 (HLR-12) | Schedule C-4 | Cost of Gas Sold for the Historical Year Ended December 31, 2023; |
| Exhibit A-3 (HLR-13) | Schedule C-5 | Operation and Maintenance Expenses for the Historical Year Ended December 31, 2023; |
| Exhibit A-3 (HLR-14) | Schedule C-5.1 | Operation and Maintenance Expenses by Witness for the Historical Year Ended December 31, 2023; |
| Exhibit A-3 (HLR-15) | Schedule C-6 | Depreciation and Amortization Expenses for the Historical Year Ended December 31, 2023; |

| | | |
|---|---|---|
| Exhibit A-3 (HLR-16) | Schedule C-7 | General Taxes for the Historical Year Ended December 31, 2023; |
| Exhibit A-3 (HLR-17) | Schedule C-8 | Federal Income Taxes for the Historical Year Ended December 31, 2023; |
| Exhibit A-3 (HLR-18) | Schedule C-9 | State Income Taxes for the Historical Year Ended December 31, 2023; |
| Exhibit A-3 (HLR-19) | Schedule C-10 | Other (or Local) Taxes for the Historical Year Ended December 31, 2023; |
| Exhibit A-3 (HLR-20) | Schedule C-11 | Allowance for Funds Used During Construction for the Historical Year Ended December 31, 2023; |
| Exhibit A-3 (HLR-21) | Schedule C-12 | Income Tax Effect of Interest for the Historical Year Ended December 31, 2023; |
| Exhibit A-3 (HLR-22) | Schedule C-13 | Interest Synchronization Adjustment for the Historical Year Ended December 31, 2023; |
| Exhibit A-4 (HLR-23) | Schedule D-1 | Capital Structure and Rate of Return Summary for the Historical Year Ended December 31, 2023; |
| Exhibit A-4 (HLR-24) | Schedule D-2 | Cost of Long-Term Debt (Excluding Securitization) for the Historical Year Ended December 31, 2023; |
| Exhibit A-4 (HLR-25) | Schedule D-3 | Cost of Short-Term Debt for the Historical Year Ended December 31, 2023; |
| Exhibit A-4 (HLR-26) | Schedule D-4 | Cost of Preferred Stock for the Historical Year Ended December 31, 2023; and |
| Exhibit A-4 (HLR-27) | Schedule D-5 | Cost of Common Shareholder's Equity for the Historical Year Ended December 31, 2023. |

**Q. How are these exhibits organized?**

A. The exhibits are organized into schedules that present the development of the revenue sufficiency (Schedule A), rate base (Schedule B), adjusted net operating income ("NOI") (Schedule C), and rate of return (Schedule D).

**Q. Who is sponsoring the historical year Schedule E exhibits?**

A. Company witness Mustafa Ahmed sponsors the historical year Schedule E exhibits.

**Q. Please describe the Schedule A exhibits for the historical year.**

A. Exhibit A-1 (HLR-1), Schedule A-1, presents the computation of the revenue sufficiency for the historical year. Exhibit A-1 (HLR-1), Schedule A-1 is developed from the financial data presented in Schedules B, C, and D described below.

Exhibit A-1 (HLR-2), Schedule A-2, is a multiple page exhibit that provides financial metrics on a financial basis (pages 1 through 3) and on a ratemaking basis (pages 4 through 6) for the years 2019 through 2023. The calculation of the return on equity for each of these years can be found on pages 1 and 4.

**Q. Please describe the Schedule B exhibits for the historical year.**

A. Exhibit A-2 (HLR-3), Schedule B-1, presents the calculation of the average rate base for the historical year. The total rate base on line 8 of Exhibit A-2 (HLR-3), Schedule B-1, is carried forward to Exhibit A-1 (HLR-1), Schedule A-1, line 1. Exhibit A-2 (HLR-4), Schedule B-2, through Exhibit A-2 (HLR-8), Schedule B-6, support the development of the various components of historical rate base including net utility plant and working capital.

**Q. Please describe the Schedule C exhibits for the historical year.**

A. Exhibit A-3 (HLR-9), Schedule C-1, presents the calculation of adjusted NOI for the historical year. The adjusted NOI disclosed on line 36 of Exhibit A-3 (HLR-9), Schedule C-1, is carried forward to Exhibit A-1 (HLR-1), Schedule A-1, line 2. Exhibit A-3 (HLR-10), Schedule C-2, through Exhibit A-3 (HLR-22), Schedule C-13, support the development of the various components of adjusted NOI for the historical year. Schedule C data for the historical year is generally sourced to the Company's 2023 Form P-522 Annual Report. In addition, Exhibit A-3 (HLR-14), Schedule C-5.1, reconciles the historical year operating and maintenance ("O&M") expense by account, by witness, with the O&M expense amounts filed in the Company's 2023 Form P-522 Annual Report.

**Q. Please describe the Schedule D exhibits for the historical year.**

A. Exhibit A-4 (HLR-23), Schedule D-1, presents the overall rate of return summary for the historical year. The total weighted cost of capital is shown on line 14, column (h), and is carried forward to Exhibit A-1 (HLR-1), Schedule A-1, line 4. Exhibit A-4 (HLR-24), Schedule D-2, through Exhibit A-4 (HLR-27), Schedule D-5, support the development of various components of the overall rate of return for the historical year, including debt, preferred stock, common equity, and other sources of financing.

**Q. Based on your review of the historical year exhibits, was there a revenue deficiency in the historical year?**

A. No. I have calculated a revenue sufficiency of $9.4 million for the historical year.

**Q. Please summarize the key findings from the historical year exhibits.**

A. As presented on Exhibit A-1 (HLR-1), Schedule A-1, the key findings from the exhibits for the historical year ended December 31, 2023 are as follows:

| | *($ In Thousands)* |
|---|---|
| **Rate Base** | $ 9,479,241 |
| **Adjusted NOI** | $ 561,724 |
| **Overall Rate of Return** | 5.93% |
| **Required Rate of Return** | 5.85% |
| **Income Required** | $ 554,667 |
| **Income Sufficiency** | $ (7,057) |
| **Revenue Conversion Factor** | 1.3381 |
| **Revenue Sufficiency** | **$ (9,443)** |

**Q. Do the above results include typical ratemaking adjustments such as weather, unusual, one-time, or out-of-period items, and regulatory disallowances?**

A. Yes. The historical year presentation begins with the Company's booked results and ratemaking adjustments and normalizations are recognized, where appropriate, as summarized on Exhibit A-3 (HLR-9), Schedule C-1. I will discuss the ratemaking adjustments and normalizations in Section II of my direct testimony, which covers the projected test year.

## II. PROJECTED TEST YEAR

**Q. What is the projected test year used in your exhibits and supporting testimony?**

A. The projected test year is the 12-month period ending October 31, 2026.

**Q. Please identify the exhibits that you are sponsoring to comply with the Commission's Filing Requirements for the projected test year.**

A. The following exhibits are being submitted to support and satisfy the projected test year Filing Requirements:

| | | |
|---|---|---|
| Exhibit A-11 (HLR-28) | Schedule A-1 | Revenue Deficiency (Sufficiency) for the Projected 12-Month Period Ending October 31, 2026; |
| Exhibit A-11 (HLR-29) | Schedule A-2 | Financial Metrics – Ratemaking Basis – For the Projected 12-Month Period Ending October 31, 2026, Gas Results Only; |
| Exhibit A-11 (HLR-30) | Schedule A-3 | Comparison of the Historical and Projected Revenue Requirement for the Projected 12-Month Period Ending October 31, 2026; |
| Exhibit A-12 (HLR-31) | Schedule B-1 | Rate Base for the Projected 12-Month Period Ending October 31, 2026; |
| Exhibit A-12 (HLR-32) | Schedule B-2 | Total Utility Plant for the Projected 12-Month Period Ending October 31, 2026; |
| Exhibit A-12 (HLR-33) | Schedule B-3 | Depreciation Reserve and Other Deductions for the Projected 12-Month Period Ending October 31, 2026; |
| Exhibit A-12 (HLR-34) | Schedule B-4 | Working Capital for the Projected 12-Month Period Ending October 31, 2026; |
| Exhibit A-12 (HLR-35) | Schedule B-5 | Capital Expenditures Summary for the Projected 12-Month Period Ending October 31, 2026; |
| Exhibit A-13 (HLR-36) | Schedule C-1 | Adjusted Net Operating Income for the Projected 12-Month Period Ending October 31, 2026; |

| | | |
|---|---|---|
| Exhibit A-13 (HLR-37) | Schedule C-1.1 | Development of Adjusted Net Operating Income for the Projected 12-Month Period Ending October 31, 2026; |
| Exhibit A-13 (HLR-38) | Schedule C-2 | Calculation of the Revenue Conversion Factor for the Projected 12-Month Period Ending October 31, 2026; |
| Exhibit A-13 (HLR-39) | Schedule C-3 | Operating Revenues for the Projected 12-Month Period Ending October 31, 2026; |
| Exhibit A-13 (HLR-40) | Schedule C-4 | Cost of Gas Sold for the Projected 12-Month Period Ending October 31, 2026; |
| Exhibit A-13 (HLR-41) | Schedule C-5 | Operation and Maintenance Expenses for the Projected 12-Month Period Ending October 31, 2026; |
| Exhibit A-13 (HLR-42) | Schedule C-5.1 | Summary of Inflation and Merit Increases Included in Operation and Maintenance Expenses for the Projected 12-Month Period Ending October 31, 2026; |
| Exhibit A-13 (HLR-43) | Schedule C-6 | Depreciation and Amortization Expenses for the Projected 12-Month Period Ending October 31, 2026; |
| Exhibit A-13 (HLR-44) | Schedule C-7 | General Taxes for the Projected 12-Month Period Ending October 31, 2026; |
| Exhibit A-13 (HLR-45) | Schedule C-8 | Federal Income Taxes for the Projected 12-Month Period Ending October 31, 2026; |
| Exhibit A-13 (HLR-46) | Schedule C-9 | State Income Taxes for the Projected 12-Month Period Ending October 31, 2026; |
| Exhibit A-13 (HLR-47) | Schedule C-10 | Other (or Local) Taxes for the Projected 12-Month Period Ending October 31, 2026; |

| | | |
|---|---|---|
| Exhibit A-13 (HLR-48) | Schedule C-11 | Allowance for Funds Used During Construction for the Projected 12-Month Period Ending October 31, 2026; |
| Exhibit A-13 (HLR-49) | Schedule C-12 | Income Tax Effect of Interest for the Projected 12-Month Period Ending October 31, 2026; |
| Exhibit A-13 (HLR-50) | Schedule C-13 | Interest Synchronization Adjustment for the Projected 12-Month Period Ending October 31, 2026; and |
| Exhibit A-92 (HLR-51) | | Pension and OPEB Volatility Mechanism - Amortization Expense for the Projected 12-Month Period Ending October 31, 2026. |

**Q. Please discuss the organization and format of the projected test year exhibits.**

A. The projected test year exhibits are organized and formatted in a similar fashion to the historical year exhibits. The exhibits are organized into schedules that present the development of the revenue deficiency (Schedule A), rate base (Schedule B), and adjusted NOI (Schedule C). Company witness Marc R. Bleckman is sponsoring schedules that address rate of return (Schedule D). Company witness Ahmed is sponsoring sales, load, and customer data (Schedules E) exhibits. Company witnesses Samuel M. Geller, S. Austin Smith, and Kirkland D. Harrington are sponsoring cost-of-service allocation, present and proposed revenue, and proposed tariff sheets (Schedule F) exhibits, respectively.

**Q. Please summarize the key findings for the projected test year exhibits.**

A. As presented on Exhibit A-11 (HLR-28), Schedule A-1, the key findings from the exhibits for the projected 12-month period ending October 31, 2026 are as follows:

| | ($ In Thousands) |
|---|---|
| **Rate Base** | $ 11,750,740 |
| **Adjusted NOI** | $ 545,492 |
| **Overall Rate of Return** | 4.64% |
| **Required Rate of Return** | 6.22% |
| **Income Required** | $ 730,838 |
| **Income Deficiency** | $ 185,346 |
| **Revenue Conversion Factor** | 1.3381 |
| **Revenue Deficiency** | **$ 248,008** |

**Q. What inflation factors is the Company using in its presentation?**

A. The Company utilized the inflation factors published by S&P Global, a leader in the market of financial information and analytics. The inflation factors in the June 2024 edition of S&P Global's *U.S. Economic Outlook* publication were 3.2% for 2024, 2.4% for 2025, and 2.5% for 2026.[1] Exhibit A-13 (HLR-42), Schedule C-5.1, provides a summary of the inflation impacts included in this instant case.

**Q. How has the Company addressed the filing requirement to reconcile the projected test year to the most recent calendar year?**

A. The following exhibits reconcile the projected test year to the historical year:

i. Exhibit A-11 (HLR-30), Schedule A-3;

ii. Exhibit A-12 (HLR-34), Schedule B-4;

iii. Exhibit A-13 (HLR-37), Schedule C-1.1;

iv. Exhibit A-13 (HLR-41), Schedule C-5; and

v. Exhibit A-13 (HLR-42), Schedule C-5.1.

[1] 2.1% based on a 10-month proration to align with the October 31, 2026 projected test year.

**Q. Please explain Exhibit A-11 (HLR-29), Schedule A-2.**

A. This exhibit presents the financial metrics for the projected test year as required by the Filing Requirements. Column (b) shows metrics assuming no rate relief is granted. Column (c) shows metrics assuming the full rate relief request is granted.

**Q. Please explain Exhibit A-11 (HLR-30), Schedule A-3.**

A. This exhibit presents a comparison of the historical and projected year revenue deficiency for Consumers Energy. Column (d) of the exhibit presents rate base and rate of return amounts for the historical year. Column (e) shows the changes resulting from adjustments as supported by the various Company witnesses that were made in developing the projected test year revenue requirement. Column (f) shows the rate base, income requirement, and revenue requirement for the projected test year.

**Q. What are the major differences between the historical year and the projected test year results shown on Exhibit A-11 (HLR-30), Schedule A-3?**

A. The comparison of historical and projected results in Exhibit A-11 (HLR-30), Schedule A-3, shows that rate base increases by approximately $2.3 billion (line 7) and the rate of return increases from 5.85% to 6.22% (line 8). In addition, adjusted NOI (line 10) decreases by approximately $16.2 million from the historical year to the projected test year.

**Q. Please describe Exhibit A-12 (HLR-31), Schedule B-1.**

A. Exhibit A-12 (HLR-31), Schedule B-1, is a summary presentation of the projected test year rate base. The total rate base for the 12 months ending October 31, 2026 is approximately $11.8 billion as disclosed on line 8.

**Q. Please describe Exhibit A-12 (HLR-32), Schedule B-2.**

A. Exhibit A-12 (HLR-32), Schedule B-2, shows the total utility plant for the projected test year. The total on line 25 is carried forward to line 1 on Exhibit A-12 (HLR-31), Schedule B-1.

**Q. Please describe how the projected test year average utility plant and related amounts were developed.**

A. Utility plant and reserve balances for the projected test year were developed by calculating a 13-month average of the balances from October 31, 2025 through October 31, 2026. Actual calendar year 2023 balances for construction work-in-progress ("CWIP"), gross plant, and accumulated provision for depreciation were used as the starting point. Projected capital expenditures (including Allowance for Funds Used During Construction ("AFUDC")) and plant additions were added for the calendar year 2023, calendar year 2024, and for the ten months ending October 31, 2026; followed by adjustments for projected retirements, depreciation expense, cost of removal, the calculation of the ending balances for CWIP, plant, and the accumulated provision for depreciation.

**Q. Please describe Exhibit A-12 (HLR-33), Schedule B-3.**

A. Exhibit A-12 (HLR-33), Schedule B-3, presents the depreciation reserve for the projected test year by functional group. The total on line 18 is carried forward to line 2 on Exhibit A-12 (HLR-31), Schedule B-1. The increase in projected depreciation reserve incorporates projected depreciation expense from Exhibit A-13 (HLR-43), Schedule C-6, which I describe later in my testimony.

**Q. Please explain Exhibit A-12 (HLR-34), Schedule B-4.**

A. Exhibit A-12 (HLR-34), Schedule B-4, develops the Company's proposed projected test year working capital. The starting point for this exhibit is the historical year working capital (column (b)), which is adjusted to reflect the 13-month average June 2024 ending balances shown in column (d), the most current study practical for inclusion at the time of assembling the case. The June 2024 average balances are then adjusted to reflect changes to:

i. cash based on projections sponsored by Company witness Bleckman;

ii. gas stored underground as sponsored by Company witness Timothy K. Joyce and the corresponding adjustment to accounts payable;

iii. prepaid cloud computing balances sponsored by Company witness Stacy H. Baker;

iv. pension and other post-employment benefits ("OPEB") balances based on projections sponsored by Company witness Kendra K. Grob;

v. the regulatory asset and liability related to the pension and OPEB volatility mechanism;

vi. accrued tax balances;

vii. deferred debits for a Standardization Engineering Analysis adjustment sponsored by Company witness Michael P. Griffin;

viii. the regulatory asset related to the projected loss on the sale of the Riverside Storage Facility discussed below in Section III of my testimony; and

ix. deferred debits for a software implementation deferral as sponsored by Company witness Baker.

**Q. Why did the Company use the Balance Sheet Method in determining working capital?**

A. Use of the Balance Sheet Method was mandated by the MPSC in Case No. U-7350. The Filing Requirements also require that this method be used to develop the allowance for working capital.

**Q. Please describe Exhibit A-12 (HLR-35), Schedule B-5.**

A. Exhibit A-12 (HLR-35), Schedule-B-5, provides a summary of capital spending as supported by Company witnesses Baker, Corey E. Ballinger, Jessica R. Byrom, Matthew J. Foster, Griffin, Quentin A. Guinn, Joyce, Kristine A. Pascarello, and Lincoln D. Warriner. This exhibit provides capital spending for the bridge years and the projected test year as well as the projected test year capital spending in the Company's previous gas rate case, Case No. U-21490.

**Q. Please describe Exhibit A-13 (HLR-36), Schedule C-1.**

A. Exhibit A-13 (HLR-36), Schedule C-1, presents the calculation of adjusted NOI for the projected test year of $545.5 million as shown on line 22. Total operating revenues (line 4) are netted against total operating expenses (line 16) to arrive at net operating income on line 17. Further adjustments are made on lines 18, 20, and 21, which utilize normal ratemaking practices to arrive at adjusted NOI on line 22.

**Q. Please explain Exhibit A-13 (HLR-37), Schedule C-1.1.**

A. Exhibit A-13 (HLR-37), Schedule C-1.1, presents the reconciliation of historical year NOI to projected test year NOI. The exhibit presents revenues in columns (c) through (e), expenses in columns (f) through (p), NOI in column (q), AFUDC in column (r), and adjusted NOI in column (s). The exhibit begins with the historical year on line 1, normalizing adjustments to the historical year on lines 2 through 17, and projected test year adjustments on lines 18 through 32. Total adjusted NOI for the projected test year is shown on line 33, column (s). In general, the revenue and expense adjustments are shown with their accompanying tax impacts to arrive at the adjusted NOI. The historic year NOI of

$473.1 million on line 1, column (s), ties to the historic NOI on line 19 of Exhibit A-3 (HLR-9), Schedule C-1.

**Q. Please explain the adjustments on Exhibit A-13 (HLR-37), Schedule C-1.1.**

A. The adjustments on lines 2 through 16 are made to comply with prior Commission orders and follow traditional ratemaking adjustments to historical results such as: (i) removing regulatory disallowances; (ii) normalizing for unusual, one-time, or out-of-period items; (iii) bringing certain revenues and expenses "above the line"; (iv) adjusting historical revenues to reflect "normal" weather; and (v) adjusting income taxes. Additional adjustments include certain O&M expense normalizations to better align the historic year with expected expense amounts in the projected test year. These adjustments are supported by my exhibits, supporting workpapers, and the exhibits of other Company witnesses.

The historical year adjusted NOI on Exhibit A-13 (HLR-37), Schedule C-1.1, line 17, column (s), of $561.7 million ties to the adjusted NOI on Exhibit A-3 (HLR-9), Schedule C-1, line 36.

**Q. How were the projected test year adjustments on Exhibit A-13 (HLR-37), Schedule C-1.1, developed?**

A. These adjustments represent the movement from the historical year adjusted NOI to the projected test year adjusted NOI. The adjustments on lines 18 through 32 are developed from my exhibits and supporting workpapers and from the exhibits of Company witnesses Ahmed, Baker, Amy M. Conrad, Foster, Griffin, Grob, Guinn, Joyce, Pascarello, James P. Pnacek, and Brian J. Vanblarcum. The projected test year adjusted NOI on line 33 is the result of netting the projected test year adjustments on lines 18 through 32 against the historical year adjusted NOI on line 17. The projected test year adjusted NOI of

$545.5 million on line 33, column (s), ties to the projected test year adjusted NOI on Exhibit A-13 (HLR-36), Schedule C-1, line 22.

**Q. Please explain the projected test year adjustments on Exhibit A-13 (HLR-37), Schedule C-1.1.**

A. Lines 18, 19, and 21 represent the changes in gross margin from the adjusted historical year to the projected test year and are supported by Company witness Ahmed.

Line 20 represents the change in other revenues from the adjusted historical year to the projected test year and are supported by my workpapers.

Lines 22 and 23 represent the change in lost and unaccounted for ("LAUF") and company use gas, respectively, and are supported by Company witness Joyce.

Line 24 represents the change in other O&M expenses from the adjusted historical year to the projected test year and are supported by Company witnesses Baker, Byrom, Conrad, Foster, Griffin, Grob, Guinn, Joyce, Pascarello, and Pnacek. The adjustments on lines 22 through 24 are expanded on Exhibit A-13 (HLR-41), Schedule C-5 and Exhibit A-13 (HLR-42), Schedule C-5.1.

Line 25 represents the change in the book depreciation expense from the adjusted historical year to the projected test year. As stated above, the Company used the approved book depreciation rates, projected capital expenditures, and assumed plant retirements to determine the depreciation expense adjustment necessary to arrive at an appropriate level of book depreciation expense for the projected test year.

Line 26 represents the change in MGP amortization expense from the adjusted historical year to the projected test year, which is supported by Company witness Foster, the amortization of the pension and OPEB volatility mechanism, which is supported on

Exhibit A-92 (HLR-51), and the projected amortization of the Riverside Storage Field regulatory asset, Exhibit A-12 (HLR-34), Schedule B-4.

Line 27 represents an adjustment to real and personal property tax to the projected test year amount supported by Company witness VanBlarcum and shown on Exhibit A-13 (HLR-44), Schedule C-7, line 1.

Line 28 represents the change in historical year payroll and other general taxes to the projected test year amount as shown on Exhibit A-13 (HLR-44), Schedule C-7, lines 6 and 15.

Line 29 represents the impact of City Income Tax ("CIT"). The projected test year CIT expense is shown on Exhibit A-13 (HLR-47), Schedule C-10.

Line 30 reflects the impact of Michigan Corporate Income Tax ("MCIT"). The projected test year MCIT expense is shown on Exhibit A-13 (HLR-46), Schedule C-9.

Line 31 represents the Federal Income Tax ("FIT") adjustments which result from the other changes in revenues and expenses in the projected test year. Line 31 also reflects the differences between the FIT expense calculated at the current federal statutory rate and the actual total income tax expense. The projected test year FIT expense is shown on Exhibit A-13 (HLR-45), Schedule C-8.

Line 32 represents an adjustment to AFUDC from the adjusted historical year to the projected test year. The projected test year AFUDC is shown on Exhibit A-13 (HLR-48), Schedule C-11. AFUDC is an accounting convention that recognizes the costs, both interest and equity, of financing certain construction projects. The recognition is through the transfer of interest and equity cost from the income statement to CWIP on the balance sheet. The interest and equity costs are capitalized in

the same manner as construction labor and material costs when the project is closed to plant-in-service. The criteria for applying AFUDC to a construction project require on-site construction activities of more than six months duration and an estimated plant cost (excluding AFUDC) in excess of $50,000.

**Q. Please describe Exhibit A-13 (HLR-38), Schedule C-2.**

A. Exhibit A-13 (HLR-38), Schedule C-2, shows the development of the revenue conversion factor for the projected test year. The revenue conversion factor converts a utility's after-tax income deficiency (or sufficiency) into the required pre-tax revenue requirement. For the projected test year, the FIT rate is 21.00%, the MCIT rate is 5.24%, and the CIT rate is 0.16%, which results in a revenue conversion factor of 1.3381.

**Q. Please explain Exhibit A-13 (HLR-39), Schedule C-3.**

A. Exhibit A-13 (HLR-39), Schedule C-3, presents the total operating revenues for the projected test year. Line 1 and line 2 of this exhibit present the sales and transportation revenue supported by Company witness Ahmed. Line 3 presents the other revenues supported by my workpapers. The total on line 4 is carried forward to the Company's projected adjusted NOI presentation on Exhibit A-13 (HLR-36), Schedule C-1.

**Q. Please explain Exhibit A-13 (HLR-40), Schedule C-4.**

A. Exhibit A-13 (HLR-40), Schedule C-4, presents the cost of gas sold for the projected test year. The projected test year cost of gas sold is supported by Company witness Ahmed. This total is carried forward to line 5 of the Company's projected adjusted NOI presentation on Exhibit A-13 (HLR-36), Schedule C-1.

**Q. Please explain Exhibit A-13 (HLR-41), Schedule C-5.**

A. Exhibit A-13 (HLR-41), Schedule C-5, presents the other O&M expenses for the projected test year as compared to the historical year. The amounts on lines 1 through 26 were provided by Company witnesses Baker, Byrom, Conrad, Foster, Griffin, Grob, Guinn, Joyce, Pascarello, and Pnacek and are supported in their direct testimony and exhibits. Lines 27 through 30 are supported by my workpapers. LAUF gas (line 1), company use gas (line 2), and total O&M expense (line 34) are carried forward to lines 6, 7, and 8, respectively, of the Company's projected adjusted NOI presentation on Exhibit A-13 (HLR-36), Schedule C-1.

**Q. Please explain Exhibit A-13 (HLR-42), Schedule C-5.1.**

A. Exhibit A-13 (HLR-42), Schedule C-5.1, provides a summary of inflation and merit increases included in other O&M expense. Amounts projected using a method other than inflation and merit are included in column (g). The amounts on lines 1 through 26 were provided by Company witnesses Baker, Byrom, Conrad, Foster, Griffin, Grob, Guinn, Joyce, Pascarello, and Pnacek and are supported in their direct testimony and exhibits. Lines 27 through 30 are supported by my workpapers.

**Q. Please explain Exhibit A-13 (HLR-43), Schedule C-6.**

A. Exhibit A-13 (HLR-43), Schedule C-6, presents depreciation by functional grouping and amortization expenses for the projected test year. The total on lines 18 and 21 are carried forward to lines 9 and 10 of the Company's projected adjusted NOI presentation on Exhibit A-13 (HLR-36), Schedule C-1. The calculated depreciation expense and associated accumulated provision for depreciation presented uses the book depreciation rates approved by the Commission as follows:

1. the Settlement Agreement in Case No. U-21176 dated September 8, 2023 for gas utility plant balances; and

2. the Order in Case No. U-20849 dated December 9, 2021 for common utility plant.

Book depreciation expense was developed by applying the functional composite book depreciation rates to the average projected test year depreciable plant balances.

**Q. Does the Company have a depreciation rate case pending before the Commission that could impact depreciation expense and therefore, the revenue deficiency in this proceeding?**

A. No.

**Q. Please explain Exhibit A-13 (HLR-44), Schedule C-7, through Exhibit A-13 (HLR-48), Schedule C-11.**

A. These exhibits present the following: (i) projected general taxes; (ii) projected FITs; (iii) projected state income taxes; (iv) projected other (or local) taxes; and (v) projected AFUDC. The total from each schedule is carried forward to the Company's projected adjusted NOI presentation on Exhibit A-13 (HLR-36), Schedule C-1.

**Q. Please describe Exhibit A-13 (HLR-49), Schedule C-12.**

A. Exhibit A-13 (HLR-49), Schedule C-12, shows the calculation of pro forma interest expense for the projected test year and the corresponding impact on income taxes.

**Q. Please describe Exhibit A-13 (HLR-50), Schedule C-13.**

A. Exhibit A-13 (HLR-50), Schedule C-13, shows the calculation of the tax effect of the interest synchronization adjustment for the projected test year and the corresponding impact on income taxes.

**Q. Why are Exhibit A-13 (HLR-49), Schedule C-12, and Exhibit A-13 (HLR-50), Schedule C-13, included in the presentation?**

A. The purpose of these exhibits is to align the interest expense and the associated tax benefits in the projected test year with the amount of rate base that is financed with debt and display the alignment in a transparent manner.

## III. RATE IMPACT FROM THE SALE OF THE RIVERSIDE STORAGE FIELD

**Q. Does the Company's execution of a Purchase and Sale Agreement for the Company's Riverside Storage Field have an impact on this case?**

A. Yes. The Company executed a Purchase and Sale Agreement for the sale of the Riverside Storage Field in October 2024. As discussed by Company witness Joyce, the Company expects the sale to close before the end of 2025. Therefore, the historical net book value of this asset has been removed from this case.

The Company's current expectation is that the sale will result in a $8.9 million loss. In Case No. U-21656, the Commission approved the Company's request for cost deferral accounting and a regulatory asset for the loss associated with the sale of the Riverside Storage Field. Therefore, as previously discussed, the Company has made a projection adjustment to working capital to reflect the regulatory asset balance for the test year. The Company is requesting to amortize the regulatory asset over a three-year period.

The Company has used its best estimate of the Riverside loss to reflect the impacts within the instant case; however, actual transaction costs and customary closing adjustments may ultimately change the amount of the recorded loss. Therefore, the Company proposes to adjust the associated amortization expense in future gas rate cases to reflect any necessary adjustments for the actual realized loss on the Riverside storage field.

## IV. ACCOUNTING TREATMENT FOR MAOP RETESTING COSTS TO COMPLY WITH NEW FEDERAL SAFETY STANDARDS

**Q. Should the Commission allow the Company to adopt the accounting for MAOP retesting costs as approved by FERC in Docket No. AI20-3-000?**

A. Yes. In June 2020, the Pipeline and Hazardous Materials Safety Administration ("PHMSA") issued its final rule that addressed, among other items, the safety of gas transmission pipelines, including actions an operator must take to reconfirm the MAOP of natural gas pipelines not yet tested using the new federal safety regulations.[2]

As a result, FERC provided accounting guidance[3] stating that if a utility is required to retest the pipeline so that its full capacity can be utilized, such first-time and one-time retesting costs can be capitalized. When such retesting costs are capitalized, all prior testing costs related to the specific property should be retired. Based on this guidance, the Company is requesting approval to capitalize first-time and one-time retesting costs incurred due to the new FERC standard. Any related prior capitalized testing would be retired. Please see Company witness Griffin's testimony for further discussion related to the PHMSA transmission safety rules.

**Q. Does this complete your direct testimony?**

A. Yes.

[2] *Safety of Gas Transmission Pipelines: Maximum Allowable Operating Pressure Reconfirmation, Expansion of Assessment Requirements, and Other Related Amendments*, 84 Fed. Reg. 51480 (October 1, 2019).
[3] June 23, 2020 FERC Docket No. AI-20-3-000, effective July 1, 2020.

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

| | | |
|---|---|---|
| In the matter of the application of<br>**CONSUMERS ENERGY COMPANY**<br>for authority to increase its rates for the<br>distribution of natural gas and for other relief. | )<br>)<br>)<br>)<br>) | Case No. U-21806 |

**REBUTTAL TESTIMONY**

**OF**

**HEATHER L. RAYL**

**ON BEHALF OF**

**CONSUMERS ENERGY COMPANY**

May 2025

**Q. Please state your name and business address.**

A. My name is Heather L. Rayl, and my business address is One Energy Plaza, Jackson, Michigan 49201.

**Q. Are you the same Heather L. Rayl who previously presented direct testimony in this case?**

A. Yes.

**Q. What is the purpose of your rebuttal testimony?**

A. The purpose of my rebuttal testimony is to: (i) present an adjusted revenue deficiency reflecting the rebuttal positions of Consumers Energy Company's ("Consumers Energy" or the "Company") witnesses; and (ii) address certain arguments and recommendations related to the revenue requirement made by Sebastian Coppola on behalf of Attorney General Dana Nessel ("Attorney General"), and the Michigan Public Service Commission ("MPSC" or the "Commission") Staff ("Staff") witnesses Justin J. Hecht, Robert F. Nichols, Charles E. Putnam, and Timothy G. Witt.

**Q. Have you prepared any exhibits in conjunction with your rebuttal testimony?**

A. Yes. I am sponsoring the following exhibits:

| | |
|---|---|
| Exhibit A-146 (HLR-52) | Adjusted Revenue Deficiency for the Projected 12-Month Period Ending October 31, 2026; |
| Exhibit A-147 (HLR-53) | Adjusted Rate Base for the Projected 12-Month Period Ending October 31, 2026; |
| Exhibit A-148 (HLR-54) | Adjusted Utility Plant for the Projected 12-Month Period Ending October 31, 2026; |
| Exhibit A-149 (HLR-55) | Capital Spending Reconciliation for the Projected 12-Month Period Ending October 31, 2026; |
| Exhibit A-150 (HLR-56) | Adjusted Working Capital for the Projected 12-Month Period Ending October 31, 2026; |

| | |
|---|---|
| Exhibit A-151 (HLR-57) | Adjusted Net Operating Income for the Projected 12-Month Period Ending October 31, 2026; |
| Exhibit A-152 (HLR-58) | Reconciliation of Adjusted Net Operating Income for the Projected 12-Month Period Ending October 31, 2026; |
| Exhibit A-153 (HLR-59) | Adjusted Operations & Maintenance Expenses for the Projected 12-Month Period Ending October 31, 2026; |
| Exhibit A-154 (HLR-60) | Income Tax Effect of Interest for the Projected 12-Month Period Ending October 31, 2026; and |
| Exhibit A-155 (HLR-61) | Interest Synchronization Adjustment for the Projected 12-Month Period Ending October 31, 2026. |

**ADJUSTED REVENUE DEFICIENCY**

**Q. Please describe Exhibits A-146 (HLR-52) through A-155 (HLR-61).**

A. Exhibits A-146 (HLR-52) through A-155 (HLR-61) present the calculation of the Company's adjusted revenue deficiency for the projected 12-month period ending October 31, 2026. As shown on line 8, column (e), of Exhibit A-146 (HLR-52), the Company has recalculated a test year revenue deficiency of $217.7 million, a reduction of $30.3 million from the Company's original filing in this case.

**Q. Why is the Company proposing an adjusted test year revenue deficiency?**

A. Based on certain facts and circumstances revealed subsequent to filing the case, the Company believes it is appropriate and necessary to make the adjustments.

**Q. Please summarize the proposed adjustments to the revenue deficiency.**

A. The Company has made the following adjustments to its originally filed revenue deficiency:

1. Decrease to net utility plant of $40.3 million, depreciation expense of $11.3 million, and property tax expense of $0.9 million. A list of the individual

adjustments, with descriptions and sources, is provided on Exhibit A-148 (HLR-54) and Exhibit A-149 (HLR-55);

2. Increase to unamortized manufactured gas plant of $0.5 million and associated amortization expense of $0.1 million as discussed by Company witness Matthew J. Foster;

3. Decrease to working capital of $143.5 million. A list of the individual adjustments, with descriptions and sources, is provided on Exhibit A-150 (HLR-56); and

4. Increases to gross margin of $1.1 million and operating and maintenance ("O&M") expenses of $0.5 million and a decrease to amortization expense of $3.0 million and general tax expense of $0.5 million. A list of the individual adjustments, with descriptions and sources, is provided on Exhibit A-152 (HLR-58).

**WORKING CAPITAL**

**Q. Attorney General witness Coppola proposed adjustments to reduce the Company's working capital deferred debits balance to: (1) correct for an error made in the calculation of the S4/HANA cloud implementation adjustment (direct testimony page 106, line 5 through page 107, line 4) and (2) correct for an error in the calculation of the prepaid cloud computing adjustment (direct testimony page 107, line 5 through page 108, line 5). Do you agree with these adjustments?**

A. Yes. Based on the rebuttal testimony of Company witness Stacy H. Baker, the Company agrees with the Attorney General's reduction of the Company's working capital deferred debits balance for the correction of the S4/HANA cloud implementation and the prepaid cloud computing adjustments of $1.7 million and $1.0 million, respectively.

**Q. Attorney General witness Coppola (direct testimony page 108, line 6 through line 16) and Staff witness Nichols (direct testimony page 5, line 21 through page 6, line 14) proposed an adjustment to reduce working capital and associated amortization expense as the sale of the Riverside Storage Field was not completed as originally anticipated. Do you agree with this adjustment?**

A. Yes. Based on the rebuttal testimony of Company witness Heidi J. Myers, the Company agrees with the Attorney General witness Coppola's and Staff witness Nichols' $7.4 million reduction of the Company's working capital deferred debits balance and a $3.0 million reduction of amortization expense. As supported by Company witness Myers and Staff witness Nichols, the effects of the Riverside Storage Field sale have been removed from the revenue deficiency calculation and the plant-in-service, depreciation reserve, depreciation expense, and property tax balances related to the Riverside Storage Field have been added back to the case.

**Q. Attorney General witness Coppola (direct testimony page 108, line 17 through page 109, line 11) and Staff witness Hecht (direct testimony page 6, lines 7 through line 14) proposed an adjustment to increase accrued taxes. Do you agree with this adjustment?**

A. Yes. The Company inadvertently made an error in its calculation of accrued taxes and agrees with the Attorney General witness Coppola's and Staff witness Hecht's $127.8 million decrease in working capital.

**Q. Staff witness Hecht (direct testimony page 5, line 14 through line 21) proposed an adjustment to reduce the Company's working capital deferred debits balance to remove a non-utility account. Do you agree with this adjustment?**

A. Yes. The Company agrees with Staff witness Hecht's $0.2 million reduction of the Company's working capital deferred debits balance and the removal of the non-utility account from working capital.

**GENERAL TAX EXPENSE**

**Q. Staff witness Putnam proposed an adjustment to reduce the Company's general tax expense balance (direct testimony page 7, line 18 through page 9, line 2). Do you agree with this adjustment?**

A. Yes. The Company based its projected payroll tax expense on its historical 2023 expenses, adjusted for inflation through December 31, 2026, which is incorrect. The inflation adjustment should have ended at the October 31, 2026 test year date. In addition, the Company used its 2023 historical sales and use tax expenses as the basis for projecting sales and use taxes for the test year. Historical sales and use tax expense included an audit settlement related to activity predating 2023. Although paid in 2023, the audit settlement activity should have been excluded from the calculation of projected sales and use tax. Therefore, the Company agrees with Staff witness Putnam's $0.5 million reduction of general tax expense.

**DEPRECIATION RESERVE AND DEPRECIATION EXPENSE**

**Q. Staff witness Witt proposed an adjustment to reduce the Company's depreciation reserve (direct testimony page 6, line 2 through line 19) and depreciation expense balances (direct testimony page 7, line 17 through page 8, line 9). Do you agree with these adjustments?**

A. Yes. The Company inadvertently used the incorrect depreciation rates in the calculation of depreciation reserve and depreciation expense and agrees with Staff witness Witt's $20.4 million reduction of the depreciation reserve balance and $8.9 million reduction of depreciation expense.

**Q. Does this conclude your rebuttal testimony?**

A. Yes.

MR. RUSZKIEWICZ: Company's next witness is Austin S. Smith. Based on stipulation of the parties, Company moves to bind in the testimony of Mr. Smith. He had direct testimony which consisted of a cover letter plus 17 -- or I'm sorry, plus 18 pages of direct prefiled testimony. Also Mr. Smith had rebuttal testimony which consisted of a cover page plus 8 pages of prefiled testimony.

The Company also moves to admit the exhibits of Mr. Smith, which are A-16 Schedule F-2, A-16 Schedule F-2.1, A-16 Schedule F-2.2, A-16 Schedule F-3, A-16 Schedule F-4, A-108, A-93, A-94, and A-156. Thank you.

JUDGE VARCHETTI: Are there any objections to the binding in of Mr. Smith's direct and rebuttal testimony or any of his associated exhibits?

Hearing none, the testimony is bound into the record and the exhibits are admitted.

MR. RUSZKIEWICZ: Thank you, Your Honor.

(Direct and Rebuttal Testimony bound in)

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

| | | |
|---|---|---|
| In the matter of the application of<br>**CONSUMERS ENERGY COMPANY**<br>for authority to increase its rates for the<br>distribution of natural gas and for other relief. | )<br>)<br>)<br>)<br>) | Case No. U-21806 |

**DIRECT TESTIMONY**

**OF**

**S. AUSTIN SMITH**

**ON BEHALF OF**

**CONSUMERS ENERGY COMPANY**

December 2024

**Q. Please state your name and business address.**

A. My name is S. Austin Smith, and my business address is One Energy Plaza, Jackson, Michigan 49201.

**Q. By whom are you employed?**

A. I am employed by Consumers Energy Company ("Consumers Energy" or the "Company").

**Q. What is your position with Consumers Energy?**

A. I am a Senior Rate Analyst in the Cost and Pricing Section of the Rates and Regulation Department.

**Q. Please state your educational background and work experience.**

A. I received a Bachelor of Business Administration degree with an emphasis in Accounting in April 2014 from Alma College. In Spring 2019, I earned a Master of Business Administration degree from Spring Arbor University. In August 2016, I began employment as a Rates Analyst in the Pricing Section of the Legal, Rates & Regulatory Department at Consumers Energy. My responsibilities include preparing various electric and gas rate analyses, rate design, research, and validating electric and gas charges as part of the Company's billing process. In September 2024 I was promoted to my current position.

**Q. Have you previously filed testimony with the Michigan Public Service Commission ("MPSC" or the "Commission")?**

A. Yes. I have filed testimony in the following cases:

Case No. U-17771 (Amended) Energy Optimization Plan,

Case No. U-18261 Energy Waste Reduction ("EWR") Plan,

Case No. U-18331 EWR Reconciliation,

Case No. U-20028 EWR Reconciliation,

| | |
|---|---|
| Case No. U-20275 | Electric Self-Implementation Reconciliation, |
| Case No. U-20356 | Gas Revenue Decoupling Reconciliation, |
| Case No. U-20671 | Gas Revenue Decoupling Reconciliation, |
| Case No. U-21205 | EWR Reconciliation, |
| Case No. U-21233 | Demand Response Reconciliation, |
| Case No. U-21344 | Gas Revenue Decoupling Reconciliation, |
| Case No. U-21410 | Demand Response Reconciliation, |
| Case No. U-21490 | General Gas Rate Case, and |
| Case No. U-21784 | Residual Balance of Voluntary Refund Mechanism. |

**Q. What is the purpose of your direct testimony in this case?**

A. The purpose of my direct testimony is to present the Company's proposed rate design, which collects the proposed revenue requirement from customers in an equitable manner reflecting the cost of providing service and taking into consideration rate impacts.

**Q. Are you sponsoring any exhibits?**

A. Yes, I am sponsoring the following exhibits:

| | | |
|---|---|---|
| Exhibit A-16 (SAS-1) | Schedule F-2 | Summary of Present and Proposed Revenue by Rate Schedule; |
| Exhibit A-16 (SAS-2) | Schedule F-2.1 | Summary of Present and Proposed Rates by Rate Schedule; |
| Exhibit A-16 (SAS-3) | Schedule F-2.2 | Calculation of Rate Design Targets; |
| Exhibit A-16 (SAS-4) | Schedule F-3 | Present and Proposed Revenue Detail; |
| Exhibit A-16 (SAS-5) | Schedule F-4 | Comparison of Present and Proposed Monthly Bills; |
| Exhibit A-108 (SAS-6) | | Development of Rates for Transportation ATL Services; |

| | |
|---|---|
| Exhibit A-93 (SAS-7) | Calculation of Test Year Discount and Carrying Cost Rates for the Customer Attachment Program; and |
| Exhibit A-94 (SAS-8) | Calculation of Home Products Credit. |

**Q. Were these exhibits prepared by you or under your direction and supervision?**

A. Yes.

**Q. How is your direct testimony organized?**

A. My direct testimony is organized as follows:

I. SUMMARY OF PROPOSED RATE DESIGN CHANGES

II. ALLOCATION OF THE PROPOSED REVENUE DEFICIENCY

III. TRANSMISSION ONLY TRANSPORTATION SERVICE RATE

IV. TYPICAL BILLS

V. CUSTOMER ATTACHMENT PROGRAM DISCOUNT AND CARRYING COST

VI. HOME PRODUCTS CREDIT CALCULATION

## I. SUMMARY OF PROPOSED RATE DESIGN CHANGES

**Q. Please describe Exhibit A-16 (SAS-1), Schedule F-2.**

A. Exhibit A-16 (SAS-1), Schedule F-2, provides a summary of the proposed changes in revenue by rate schedule. The proposed change is derived from the calculated difference between test year present revenue and proposed revenue that incorporate the Company's revenue deficiency. The present and proposed revenues shown in Exhibit A-16 (SAS-1), Schedule F-2, are calculated by applying the test year billing determinants provided by Company witness Mustafa Ahmed to present rates, as well as to the rates being proposed by the Company in this case.

**Q. What rates were used to calculate present revenue?**

A. The Company applied the rates approved by the Commission in the MPSC Case No. U-21490 July 23, 2024 Order Approving Settlement Agreement ("July 23 Order") to the test year billing determinants to calculate present revenue in Exhibit A-16 (SAS-1), Schedule F-2.

**Q. Please describe the Company's objectives and approach to rate design in this case.**

A. Generally, the Company has designed rates so that the revenue recovered from each customer class reflects the adjusted costs for that class in the Company's test year Cost of Service Study ("COSS"). The Company also considers: (i) establishing rates that promote efficient use of the Company's gas system and promoting energy efficiency; (ii) establishing rates that promote a favorable business climate; and (iii) designing rates that provide the Company with a fair opportunity to collect its revenue requirements. The proposed gas delivery revenue and associated rate increases/(decreases) for each rate class are shown on Exhibit A-16 (SAS-1), Schedule F-2, page 2.

**Residential Rates**

The Company is proposing to maintain its existing residential rate structure for Rate Schedules A and A-1, which includes a fixed monthly customer charge and volumetric distribution charges. The proposed increase in distribution for Rates A and A-1 is 17.8% and 11.5% respectively, as shown on Exhibit A-16 (SAS-1), Schedule F-2, page 2. The total proposed increase for the residential class is 12.1% when including the forecasted cost of the gas commodity, as shown on Exhibit A-16 (SAS-1), Schedule F-2, page 1.

**General Service Rates**

The Company is proposing to maintain its existing rate structure for General Service Rate Schedules GS-1, GS-2, and GS-3. The proposed increase in distribution for the General Service rate class is 7.4%, as shown on Exhibit A-16 (SAS-1), Schedule F-2, page 2. The total proposed increase for the General Service class is 4.5% when including the forecasted cost of the gas commodity, as shown on Exhibit A-16 (SAS-1), Schedule F-2, page 1. The proposed rates maintain the currently established economic breakeven points between the General Service Rate Schedules, GS-1, GS-2, and GS-3.

**Transportation Rates**

The Company is proposing to maintain its existing transportation rate structure with Rate Schedules ST, LT, XLT, and XXLT. The proposed increase for the Transportation rate class is 26.9%, as shown on Exhibit A-16 (SAS-1), Schedule F-2, page 1. The proposed rates maintain the currently established economic breakeven points between the Transportation Rate Schedules ST, LT, and XLT. The Company is also proposing to modify its existing Transmission Only Transportation Service Rate.

**Q. Is the Company proposing to discontinue and close Rate GL?**

A. Yes. As noted by Company witness Kirkland D. Harrington, Rate GL will have no remaining customers by November 1, 2025.

## II. ALLOCATION OF THE PROPOSED REVENUE DEFICIENCY

**Q. Please describe Exhibit A-16 (SAS-3), Schedule F-2.2.**

A. Exhibit A-16 (SAS-3), Schedule F-2.2, shows the calculation of the revenue targets used for designing rates, including proposed adjustments, to the test year revenue requirement by rate schedule. The exhibit illustrates test year revenues based on the Company's test

year COSS (Version 2), as shown in Exhibit A-16 (SMG-2), Schedule F-1.1. This is followed by the Company's proposed adjustments to the COSS, which results in the revenue target used for designing the Company's proposed rates.

**Q. How did the Company develop the test year revenue targets for each class shown on Exhibit A-16 (SAS-3), Schedule F-2.2?**

A. As shown on Exhibit A-16 (SAS-3), Schedule F-2.2, page 1, line 1, the Company started with the test year COSS. The COSS was adjusted for the Residential Income Assistance ("RIA") provision and the Low-Income Assistance Credit ("LIAC") to assign cost responsibility for these assistance programs to all rate schedules, as shown on Exhibit A-16 (SAS-3), Schedule F-2.2, page 1, line 2. Furthermore, the COSS was adjusted to reflect the storage adjustment for Rate XXLT, as shown on Exhibit A-16 (SAS-3), Schedule F-2.2, page 1, line 3. Consistent with the methodology approved by the Commission in prior gas cases, the COSS was also adjusted to maintain economic breakeven points within the General Service and Transportation rate classes. In the interest of rate stability and to moderate rate impacts for customers on Rate GS-1, the Company is proposing to shift proposed revenue. Approximately $2.5 million has been shifted into Rate GS-2 from Rates GS-1 and Rate GS-3. Approximately $120,000 was shifted from Rate XLT to Rate LT. The adjusted cost of service was compared to the test year present revenue to determine the revenue deficiency by class. This deficiency was then adjusted for incremental late payments to determine the adjusted deficiency. The adjusted deficiency was added to the test year present revenue, resulting in the rate design targets by rate schedule as shown on Exhibit A-16 (SAS-3), Schedule F-2.2, page 1, line 11.

**Q. How did the Company allocate the low-income credits associated with the RIA credit and LIAC?**

A. The allocation of the RIA credit and LIAC is shown on Exhibit A-16 (SAS-3), Schedule F-2.2, page 2. The credits are allocated to each rate class based on that class's pro rata share of the total revenue requirement from the COSS.

**Q. What is the basis for allocating the RIA credit and LIAC among all rate schedules?**

A. The Company is maintaining the allocation ordered by the Commission in its June 3, 2010 Order in Case No. U-15985 (Michigan Consolidated Gas Company's gas general rate case) ("U-15985 Order"). The Order states:

> The ALJ found that the revenue shortfall should be recovered from all rate classes, on the basis of Allocation Factor No. 20 rather than on the basis of throughput. [U-15985 Order, page 91.]
>
> The Commission adopts the findings and recommendations of the ALJ. For the electric utilities, this shortfall is spread to all customer classes and the Commission is not persuaded that gas should be treated differently. See, MCL 460.11 (3). The Commission further finds that spreading it on the basis of cost of service plus the cost of gas is fair and reasonable. [U-15985 Order, page 92.]

**Q. Please describe Exhibit A-16 (SAS-4), Schedule F-3.**

A. Exhibit A-16 (SAS-4), Schedule F-3, calculates the test year proposed gas rates required to collect the revenue requirement derived from the test year calculation of rate design targets shown in Exhibit A-16 (SAS-3), Schedule F-2.2, page 1, line 11 for each rate schedule, based on the billing determinants provided by Company witness Ahmed. Both the present and proposed gas prices are applied to the billing determinants to calculate the test year revenue on Exhibit A-16 (SAS-1), Schedule F-2. The rates from this exhibit are

the source of the proposed rates that appear in the redlined tariffs filed by Company witness Harrington in this case.

**Q. How does the Company propose to design rates to recover the residential revenue requirement?**

A. The Company calculated a residential customer charge using the methodology originally adopted by the Commission in MPSC Case No. U-4331, January 18, 1974 Order, page 30. This methodology limits the customer charge to only those costs associated directly with supplying service to a customer, such as costs associated with metering, the service lateral, and customer billing. Using this methodology, the Company calculated a residential customer charge of $21.96 per month.

Although the Case No. U-4331 methodology supports an increase of almost $7.00 to the Company's current residential customer charge, the Company proposes a residential customer charge for Rates A and A-1 of $20.00 per month. This proposal reflects a $5.00 increase from the current $15.00 residential customer charge. Using this approach, the Company can move the residential customer charge closer to the cost to serve while at the same time allow for a more gradual increase in the fixed charge. The increase in the customer charge also results in a corresponding increase to the low-income RIA monthly credit. The more revenue collected via the fixed customer charge, the greater the proportion of the RIA customer's bill is offset by the fixed monthly credit.

**Q. Does the proposed increase in the residential customer charge result in a change to the volumetric distribution charge?**

A. Yes. The proposed $5.00 increase in the customer charge results in a volumetric distribution charge of $5.8140. If the customer charge remained at $15.00, the distribution charge would be $6.4430.

**Q. Will the increased residential customer charge increase bills for below-average users?**

A. The average monthly consumption for a residential customer is 7.0 Mcf per month. With a $20.00 customer charge and $5.8140 distribution charge, a customer with below-average usage of 4.5 Mcf (for example) would only spend $26 more annually than if they had a $15.00 customer charge and $6.4430 distribution charge.

**Q. Will the increased customer charge adversely affect customers who qualify for income assistance provisions?**

A. No. In fact, customers qualifying for the RIA provision will see the benefit of lower bills, since the customer charge is completely offset by the RIA credit.

**Q. Is the Company recommending a rate change to the Excess Peak Demand Charge for residential Rate A-1 customers?**

A. Yes. The Excess Peak Demand Charge collects the higher metering costs associated with Rate A-1 customers; therefore, the Company proposes to increase this charge by the same percent increase as the residential customer charge. The proposed Excess Peak Demand Charge is shown on Exhibit A-16 (SAS-4), Schedule F-3, page 2, line 2, column (f).

**Q. What is the Excess Peak Demand charge based on?**

A. The Excess Peak Demand charge is based on the peak month's usage over 45 Mcf because January was the typical peak usage month for Rate A-1 customers, and 45 Mcf was the

average peak monthly consumption for Rate A-1 customers when the charge was first established. The peak demand mark of 45 Mcf was first set in Case No. U-7650. In that filing, the Company testified that January was the typical peak usage month for Rate A-1 customers and 45 Mcf was the average peak monthly consumption for Rate A-1 customers in January 1982.

**Q. Is the Company recommending a change to the Excess Peak Demand usage threshold of 45 Mcf?**

A. Yes. The Company reviewed the most recent 12 months of consumption for Rate A-1 customers and found that February 2024 was the typical peak usage month and 76 Mcf was the average peak monthly consumption.

**Q. Is the Company proposing to update Contiguous Charges for both General Service and Transportation customers?**

A. Yes. Contiguous Charges have not been updated since U-20322 and are below the levels indicated by the Cost of Service Study. In the spirit of gradualism, the Company is proposing to increase the Contiguous Charges over several general rate case filings.

**Q. How does the Company propose to set rates to recover the revenue requirement for the General Service Rate Schedules GS-1, GS-2, and GS-3?**

A. Consistent with the July 23 Order, the Company is proposing principal customer charges, contiguous customer charges, and volumetric distribution charges to collect the proposed revenues. These rate changes maintain the economic breakeven points between Rate Schedules GS-1 and GS-2 at 1,000 Mcf annually and between Rate GS-2 and Rate GS-3 at 10,000 Mcf annually, as well as provide for the recovery of the annual revenue

requirement for the General Service rate class. These rate changes are shown in Exhibit A-16 (SAS-2), Schedule F-2.1.

**Q. How does the Company propose to set rates to recover the Transportation class's revenue requirement?**

A. Consistent with the July 23 Order, the Company is proposing principal customer charges, contiguous customer charges, and distribution charges to collect the Transportation proposed revenues. The principal customer charges for ST and XXLT are set based on the COSS. The principal customer charges for LT and XLT are set to maintain the economic breakeven points. The Company proposes to update the contiguous customer charges from $60 to $105 for all ST, LT, and XLT contiguous accounts. These rate changes maintain the economic breakeven point between Rate ST and Rate LT at 100,000 Mcf annually and the breakeven point between Rate LT and Rate XLT at 500,000 Mcf annually, as well as provide for recovery of the annual revenue requirement for the Transportation class. Furthermore, as approved in the July 23 Order, the Company is maintaining Rate XXLT's minimum annual eligibility requirement of 4 Bcf. These rate changes are shown in Exhibit A-16 (SAS-2), Schedule F-2.1.

**Q. Please explain economic breakeven points.**

A. An economic breakeven point is the point of volumetric usage where revenue collected from one rate would equal revenue collected on a different rate.

**Q. Is the Company proposing to reset the economic breakeven points?**

A. No. The Company's proposed rates in this case maintain the breakeven points established in Case No. U-18124, and subsequently approved in Case No. U-18424, Case

No. U-20322, Case No. U-20650, Case No. U-21148, Case No. U-21308, and Case No. U-21490.

**Q. Why does the Company strive to maintain economic breakeven points as part of the rate design?**

A. Maintaining breakeven points allows for greater precision in revenue prediction and, therefore, greater accuracy in setting rates and minimizes confusion for customers. When economic breakeven points change, customers have an economic incentive to switch from their existing rate to a more economical rate. This can result in under- and over-recovery of costs if many customers shift rates. In addition, frequent shifts from rate to rate on a large scale can create volatility in revenues received by the Company. This makes it difficult to accurately predict future revenues for ratemaking and planning purposes. Maintaining economic breakeven points minimizes volatility by eliminating any economic incentive to change rates when the customer use has not changed, while simultaneously establishing cost-based rates for the General Service class. However, it may be necessary in certain circumstances to realign the breakeven points if the individual rate classes continue to move further from their cost-basis and maintaining the current breakeven points is no longer appropriate.

**Q. The July 2023 order stated "In its next gas rate case filing, Consumers Energy will undertake two studies, with the participation and input of interested parties. The first study will examine the breakeven points and bringing the breakeven points and the customer charges closer to cost of service." How is the Company addressing the breakeven study in this filing?**

A. The Company held a collaborative meeting with interested parties to discuss options for studying the breakeven points. We discussed setting the transportation customer charges to the cost of service and recalculating new breakeven points, resetting the breakeven points based on the natural breaks in billing frequency distribution, and eliminating breakeven points and establishing a declining block rate structure. We also discussed starting with the cost of service study to inform any change to the current breakeven points. Any change to the breakevens or rate structure will require aligning the sales forecast so that customers and their usage are reflected on the appropriate rate and informing customers that there may be a more economical rate option available to them.

**Q. Is the Company proposing any changes as a result of this discussion?**

A Not at this time. The Company has proposed transportation changes that align closely with the cost of service in this case and a change to the breakeven points was not needed. However, the Company will continue to evaluate the cost of service and propose future changes to the transportation rate structure and/or breakevens should the charges get out of line again.

**Q. Please explain Authorized Tolerance Levels ("ATL").**

A. An ATL is a percentage of a transportation customer's annual contract quantity ("ACQ"). The ATL is the percentage of the ACQ which the transportation customer can have in

storage at the end of any given month without incurring additional Load Balance charges. The ACQ is based on the highest 12 consecutive months during the contract's 36-month lookback period. The ACQ is calculated either at the beginning of the contract or during the periodic review, which occurs every five years.

**Q. Is the Company proposing changes to the ATLs offered?**

A. No. Exhibit A-108 (SAS-6) provides the credit calculation, and Exhibit A-16 (SAS-4), Schedule F-3, provides the revenue calculation for each transportation rate class, consistent with the structure approved in the July 23 Order.

**Q. Is the Company proposing changes to the transportation charge adjustment associated with the ATLs?**

A. No. Consistent with the July 23 Order, the Company has directly adjusted the per Mcf storage cost based on the ratio of the ATL tiers and the weighted average ATL of 6.6%. This results in a cost per Mcf for each tier of ATL, including the 8.5% tier. The Company then adjusted each of the tiers by the 8.5% tier to keep the 8.5% tier as the neutral default level. Exhibit A-108 (SAS-6), provides this adjustment calculation.

**Q. Is the Company proposing any other changes related to the 4.0% ATL adjustment for Rate XXLT?**

A. No. Consistent with the July 23 Order, the Company has spread the 4.0% ATL adjustment given to Rate XXLT back to all other transportation rate schedules by directly adjusting the per Mcf storage cost based on the ratio of the ATL tiers and the weighted average ATL of 6.6%.

**Q. In the development of Rate Design, does the Company separate Gas Customer Choice ("GCC") sales from Gas Cost Recovery ("GCR") sales?**

A. No. The rate design calculates delivery charges for all customers. GCC and GCR customers pay the same delivery charges, thus there is no need to separate GCC sales from GCR sales. Only total sales are needed as separating them has no impact on rate design.

## III. TRANSMISSION ONLY TRANSPORTATION SERVICE RATE

**Q. Are you proposing any changes to the Transmission Only Transportation Service Rate?**

A. Yes. Currently, the Transmission Only ("TOT") Rate offers one single rate – a volumetric charge of $0.4533 per Mcf. The Company is proposing to offer four rate options (STT, LTT, XLTT, XXLTT) that consist of both a Customer Charge and a volumetric Transmission Charge.

**Q. How were the transmission only rates designed?**

A. The Company designed a transmission only rate for small, large, extra-large, and extra extra-large service which follows the full-service transportation rate schedules. The transmission costs from the cost of service, as allocated to the transportation rate schedules, were divided by the corresponding transportation sales forecast to develop a per Mcf transmission cost, as shown on Workpaper WP-SAS-5.

**Q. What change is the Company proposing to this design?**

A. Consistent with the rate design structures proposed for full transportation service customers, the Company is proposing customer charges and transportation charges to collect revenues from Transmission-Only customers. The customer charges for STT and XXLTT are set based on the COSS. The principal customer charges for LTT and XLTT

are set to maintain the economic breakeven points. These rate changes maintain economic breakeven points between Rate STT and Rate LTT at 100,000 Mcf annually and a breakeven point between Rate LTT and Rate XLTT at 500,000 Mcf annually, as well as provide for recovery of the annual revenue requirement for Transmission-related costs. Consistent with rate design proposed for full transportation service customers, and to maintain current approved breakeven points, the Company is proposing to shift proposed revenue between transmission-only rate schedules. Approximately $1.5 million has been shifted into Rates STT and LTT from Rate XLTT. Furthermore, to mirror the proposal for XXLT, the Company is proposing to maintain Rate XXLTT's minimum annual eligibility requirement of 4 Bcf. These rate changes are shown in Exhibit A-16 (SAS-2), Schedule F-2.1.

**Q. How will the revenue from customers on this rate be treated?**

A. The revenue from these customers will be included in Other Revenue and will serve as an offset to the Company's revenue requirement. This is consistent with how Act 9 customer revenue is treated today.

**Q. Did the Company project any customer usage and revenue during the test year?**

A. The Company does expect that some customers could take this rate during the test year given the termination dates of existing Act 9 contracts. However, the usage for the test year is expected to be minimal and the revenue will not be significantly different from what is included in other revenue for the Act 9 contracts today. Therefore, the Company did not make any adjustments to sales or revenue for this proposal.

## IV. TYPICAL BILLS

**Q. Please describe Exhibit A-16 (SAS-5), Schedule F-4.**

A. Exhibit A-16 (SAS-5), Schedule F-4, provides the impacts resulting from the proposed gas rates and rate design changes for customers on each rate schedule at various usage levels. This exhibit is used to gauge the distribution of the rate impacts across the population of customers taking gas service under the various rate schedules.

## V. CUSTOMER ATTACHMENT PROGRAM DISCOUNT AND CARRYING COST

**Q. Please explain Exhibit A-93 (SAS-7).**

A. Exhibit A-93 (SAS-7) provides the calculation of the test year discount and carrying cost rates for the Customer Attachment Program ("CAP") and is used to support the changes to the CAP tariff sheet sponsored by Company witness Harrington.

## VI. HOME PRODUCTS CREDIT CALCULATION

**Q. Please describe Exhibit A-94 (SAS-8).**

A. The Settlement Agreement in Case No. U-21490 provides for the Company to share three fourths of the gain related to the Home Energy Products sale or $82,500,000 over a three-year period from October 1, 2024 through September 30, 2027 through the Home Products Credit. Exhibit A-94 (SAS-8) calculates a credit to each rate schedule to provide $27,500,000 over a twelve-month period effective on and after November 1, 2025 using the same methodology as approved in Case No. U-21490. Exhibit A-94 (SAS-8) shows the proposed volumetric credit per Mcf, by rate schedule. This was calculated using Company witness Ahmed's forecasted test year sales. The proposed refund was allocated

to the customer classes using the allocation provided by Company witness Samuel M. Geller.

**Q. Does this complete your direct testimony?**

A. Yes.

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

| | | |
|---|---|---|
| In the matter of the application of<br>**CONSUMERS ENERGY COMPANY**<br>for authority to increase its rates for the<br>distribution of natural gas and for other relief. | )<br>)<br>)<br>)<br>) | Case No. U-21806 |

# REBUTTAL TESTIMONY

# OF

# S. AUSTIN SMITH

# ON BEHALF OF

# CONSUMERS ENERGY COMPANY

May 2025

**Q. Please state your name and business address.**

A. My name is S. Austin Smith, and my business address is One Energy Plaza, Jackson, Michigan 49201.

**Q. Are you the same S. Austin Smith who previously submitted testimony in this case on behalf of Consumers Energy Company ("Consumers Energy" or the "Company")?**

A. Yes, I am.

**Q. What is the purpose of your rebuttal testimony?**

A. The purpose of my rebuttal testimony is to respond to rate design proposals raised in the direct testimony of Michigan Public Service Commission ("MPSC" or "the Commission") Staff ("Staff") witness Nancy C. Rademacher, Association of Businesses Advocating Tariff Equity ("ABATE") witness Jessica A. York, Attorney General witness Sebastian Coppola, and Citizens Utility Board of Michigan ("CUB") witness Joshua W. Denzler.

**Q. Are you sponsoring any exhibits in connection with your rebuttal testimony?**

A. Yes. I am sponsoring Exhibit A-156 (SAS-9), which is a discovery response from CUB witness Denzler.

**Q. Staff witness Rademacher, on page 4, lines 4 through 8, of her direct testimony supports updating the Excess Peak Demand threshold from 45 Mcf to 92 Mcf for Rate A-1 customers. Do you agree?**

A. Yes.

**Q. Staff witness Rademacher, on page 5, line 20, through page 6, line 5, of her direct testimony proposes adjusted rate stability targets. Do you find these adjusted rate stability targets to be reasonable?**

A. Yes.

**Q. Staff witness Rademacher, on page 5, lines 1 and 2, of her direct testimony testified that the Company's proposed Transmission-Only Transportation Service rates do not reflect the breakeven points of the associated rate schedules. Do you agree?**

A. No. This appears to mirror the stance Staff witness Rademacher took in the last case, when the Company did fail to include Customer Charges and associated breakeven points with the four proposed rate schedules. But in the instant case, the rates are set according to the same breakeven point thresholds used by the Transportation class rate schedules. This is discussed on page 15, line 23, through page 16, line 3, of my direct testimony.

**Q. Staff witness Rademacher, on page 5, lines 3 through 8, of her direct testimony testified that the service provided to Transmission-Only Transportation Service customers has not been shown to differ in a way that supports separate rates for the breakeven-based classes. Do you agree?**

A. No, I do not agree. In the last gas rate case, Case No. U-21490, the Company did not fully align its Transmission-Only Transportation Service rate design with the breakeven methodology used for other transportation classes. The Company has now developed and applied breakeven points for Transmission-Only customers consistent with how rates are designed for end-use transportation customers. This approach ensures internal consistency across all transportation rate classes and better reflects cost-causation principles. The use of breakeven analysis in designing these rates helps determine appropriate fixed and variable components while supporting rate stability for customers.

**Q. What do you make of Staff witness Rademacher's argument on page 5, lines 6–8, of her testimony that the Company should design rates for Transmission-Only customers consistent with DTE?**

A. Other regulated utilities' rate designs should not prevent the Commission from approving a different rate structure for Consumers Energy, where justified by the Company's cost-of-service analysis and customer usage patterns.

**Q. Attorney General witness Coppola, on page 196, line 13, through page 198, line 3, of his direct testimony, recommended the Company not increase the residential and GS-1 customer charges. Do you agree with this recommendation?**

A. No. The Attorney General's recommendations regarding the customer charges are not based on any cost study. If the final Commission-approved Cost-of-Service Study supports a residential customer charge greater than $15.00 and a GS-1 customer charge greater than $21.00, then these customer charges should be designed to reflect that higher cost. Both the Company and Staff have independently calculated the residential customer charge using a methodology that limits the charge to costs directly associated with supplying service, such as metering, service laterals, and customer billing. These calculations support a higher charge than currently assessed, and the Company's calculation is even higher than it has proposed, indicating that the increase is justified by the actual Cost-of-Service Study. Further, as expressed by Staff witness Krause in his direct testimony, previous rate cases have resulted in smaller increases or no increase in customer charges due to settlements, which has widened the gap between calculated and approved charges over time. The proposed increase aims to address this growing disparity.

**Q. Does an increase in the Customer Charge negatively impact low-income customers on the residential income assistance ("RIA") provision?**

A. No. A higher customer charge is beneficial for low-income customers on the RIA provision. As I noted in my direct testimony, the customer charge is completely offset by the RIA credit. Further, when a larger portion of the proposed revenue is collected via a fixed charge (i.e. customer charge), a smaller portion of the proposed revenue is collected via a variable charge (i.e. distribution charge). A lower variable charge results in a lower monthly bill for the most vulnerable customers; especially during the winter when customer use is at its highest. The following example illustrates how a low-income residential customer on the RIA provision would have a *lower* monthly bill with a $20.00 customer charge using the proposed rate design methodology as compared to a $15.00 customer charge using the same proposed methodology.

**Table 1**
**Customer Charge Impact to RIA Customers**

| | | | $20.00 Customer Charge | | $15.00 Customer Charge | |
|---|---|---|---|---|---|---|
| Description | Quantity | Units | Rates | Revenue | Rates | Revenue |
| Delivery | | | | | | |
| Customer | 12 | Mthly | $ 20.00 | $ 240.00 | $ 15.00 | $ 180.00 |
| Distribution Mcf/mth[1] | 78 | Mcf | 5.8140 | 453.49 | 6.4430 | 502.55 |
| Provisions | | | | | | |
| Income Assistance - RIA | 12 | Mthly | (20.00) | (240.00) | (15.00) | (180.00) |
| Total Delivery | | | | 453.49 | | 502.55 |
| Fuel | | | | | | |
| GCR Sales | 78 | Mcf | 3.296 | 257.09 | 3.296 | 257.09 |
| Total Annual Expense | | | | $ 710.58 | | $ 759.64 |
| Average Monthly Expense | | | | $ 59.21 | | $ 63.30 |
| Percent Increase/(Decrease) | | | | | | 6.9% |

Notes
[1] Based on the 2023 average annual use for RIA customers of 78 Mcf

**Q. CUB witness Denzler, on page 32, line 12, through page 35, line 14, of his direct testimony, has said he opposes increasing the customer charge for four reasons: 1) customer charges are regressive and harm low-to-moderate income ("LMI") customers; 2) higher customer charges do not send good price signals; 3) customers prefer lower customer charges; and 4) the Company's current fixed charge is high compared to other Michigan utilities. How do you respond to Mr. Denzler's first reason?**

A. The assertion that fixed customer charges are inherently regressive and harms LMI customers oversimplifies both the nature of utility cost recovery and the broader tools available to support affordability. As provided in Table 1 above, low-income customers receiving the RIA credit benefit from a higher customer charge. The Company acknowledges that all low-income customers may not receive the RIA credit and recognizes that affordability is a valid consideration, particularly for LMI customers, but affordability issues are better addressed through targeted low-income assistance programs (e.g. RIA and LIAC) and energy efficiency investments provided by the Company's Energy Waste Reduction programs.

**Q. What is the impact to customers who do not receive the RIA provision credit?**

A. Even without the RIA provision credit, this means that any customer (LMI or otherwise) paying a $20.00 Customer Charge and consuming 8 Mcf or more per month actually experiences a *lower* bill. In addition, usage is not a reliable proxy for income, as many LMI households (e.g. those with larger families or in less efficient homes) may have higher usage than financially advantaged, single-occupant households.

**Q. How do you respond to Mr. Denzler's second reason?**

A. By removing fixed costs from the volumetric rate, the remaining usage-based rate more closely reflects the marginal cost of delivering gas. This allows customers to see the real cost of additional usage, improving the accuracy and efficiency of the price signal for conservation or behavioral response. Customer Charges do not eliminate price signals that prompt conservation, as a majority of a residential customer's typical bill is composed of a volumetric rate for gas delivery and commodity supply. Therefore, even with a higher Customer Charge, those volumetric charges and commodity prices have a consequential influence on energy efficiency programs, weatherization, and consumption-based decisions.

**Q. How do you respond to Mr. Denzler's third reason?**

A. Mr. Denzler's testimony relies on the position of the National Association of State Utility Advocates ("NASUCA"), but it is not clear if they have conducted a survey of Consumers Energy's customers. NASUCA's position represents a broad policy stance and does not seem to account for the unique circumstances of individual utilities or regions. It does not reflect a detailed analysis of Consumers Energy's specific cost structures or regional characteristics.

**Q. How do you respond to Mr. Denzler's fourth reason?**

A. Comparing fixed charges across utilities without examining the underlying cost-of-service studies, system configurations, and customer demographics is an oversimplification that can lead to flawed conclusions. Each utility's customer charge is based on the unique costs it incurs to serve a residential customer—such as meter installation and maintenance, service lines, billing, call center operations, and customer information systems. In response

to discovery, Mr. Denzler conceded that he has not evaluated whether other Michigan utilities' service areas or customer demographics contributed to their different customer charges. Exhibit A-156 (SAS-9). Rate design should be based on the utility's actual cost to serve its customers, not on simplistic benchmarking against other utilities whose cost structures may differ. The Company's fixed customer charge is based on its own cost-of-service study, which reflects the actual costs incurred to maintain safe and reliable service for each customer.

**Q. ABATE witness York, on page 13, line 12, through page 17, line 6, of her direct testimony, proposes a revenue apportionment methodology to design rates. Do you agree with this approach?**

A. No. ABATE witness York proposes a revenue apportionment methodology to adjust rate design outcomes to reflect her preferred Version 3 cost-of-service study, which utilizes an Average and Excess Demand ("AED") allocator. However, she simultaneously concedes that if the Commission adopts the Company's Version 2 COSS, her apportionment approach could be used to approximate the results of her Version 3 COSS. Rather than using a COSS to guide revenue allocation, witness York is relying on revenue apportionment—essentially shifting revenue between classes without a supporting cost basis. Revenue apportionment that shifts cost recovery between rate schedules to reflect a rejected cost-allocation method undermines the very purpose of conducting a COSS in the first place.[1]

[1] In Case No. U-21291, the Commission rejected ABATE's proposed AED allocation method. See MPSC Case No. U-21291, November 7, 2024 Order, pages 224, 228-229.

**Q. ABATE witness York, on page 37, line 8 through line 19, of her direct testimony, opposed the Company's transportation service rate design, which is based on economic breakeven points. Ms. York argues that the Company has not provided evidence to show that frequent rate shifting and revenue volatility would occur if rates for all Transportation rate schedules were based on the class COSS rather than a desire to maintain economic breakeven points. How do you respond?**

A. The Company is justifiably concerned about rate shifting—a concern grounded in both experience and sound ratemaking principles. Current approved breakeven points reflect economic thresholds that guide how customers evaluate their rate class alignment. If the Company were to abruptly shift transportation rates to align precisely with the current class COSS without considering these breakeven points—or without re-running the full forecasting and cost-allocation process—there is a material risk of distorting cost recovery. Specifically, the Company could experience customer migration between rate classes or changes in usage patterns, leading to either over-recovery or under-recovery of authorized revenues. Rate design and customer class assignment are part of a cyclical, iterative process. If these thresholds were altered midstream—without adjusting load forecasts, usage patterns, and cost allocations accordingly—it would invalidate the assumptions embedded in the class COSS and result in rates that no longer align with actual cost causation.

**Q. ABATE witness York, on page 37, lines 10 and 11, of her direct testimony, notes that minimal rate shifting has occurred over the last several years. What does this show?**

A. This shows that the Company has appropriately set breakeven points.

**Q. ABATE witness York, on page 39, line 8 through line 16, of her direct testimony, describes her proposed rate design calculated in Exhibit AB-4, which recommends the Commission set LT & XLT Customer Charges at the cost of service and establish new breakeven thresholds. Do you agree with this proposed rate design?**

A. No. Exhibit AB-4 does not consider the impact that changing the breakeven points has on sales determinants—and the related rate revenue. A much more thorough analysis would be needed to properly calculate rate impacts with ABATE witness York's proposed breakeven points. Modifying the breakeven points requires a new forecast of sales determinants. This is a cyclical process in that the Company would need to develop the cost of service and rate design using today's breakeven points, calculate the new breakeven points, and then reforecast the sales to align with the new breakeven points and rerun the cost of service and rate design. Additionally, changing breakeven points provides an incentive for customers to switch rates. The Company would need to communicate to customers that they may be better off on a different rate, and if customers do not shift to the most economical rate in response, it could lead to an over- or under-recovery of costs. The Company has engaged in collaborative discussions with ABATE and Staff to explore options for studying breakeven points, alternative rate designs, and aligning customer charges with the cost of service. This collaborative approach ensures that any changes to rate design are informed by stakeholder input and aligned with broader regulatory objectives.

**Q. Does this conclude your rebuttal testimony?**

A. Yes.

MR. RUSZKIEWICZ: The Company's next witness is Brian M. Snyder. Based on stipulation of the parties, the Company moves to bind in the testimony of Mr. Snyder. He had rebuttal testimony, which consisted of a cover page, plus 13 pages of prefiled testimony. The Company also moves to admit in Mr. Snyder's exhibit, which was A-157, please.

JUDGE VARCHETTI: Are there any objections to binding in the testimony of Mr. Snyder or the associated exhibit?

Hearing none, then, the testimony is bound into the record, and the exhibit is admitted.

MR. RUSZKIEWICZ: Thank you, Your Honor.

(Rebuttal Testimony bound in)

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

| | | |
|---|---|---|
| In the matter of the application of<br>**CONSUMERS ENERGY COMPANY**<br>for authority to increase its rates for the<br>distribution of natural gas and for other relief. | )<br>)<br>)<br>)<br>) | Case No. U-21806 |

**REBUTTAL TESTIMONY**

**OF**

**BRIAN M. SNYDER**

**ON BEHALF OF**

**CONSUMERS ENERGY COMPANY**

May 2025

**Q. Please state your name and business address.**

A. My name is Brian M. Snyder, and my business address is 11801 Farmington Road, Livonia, Michigan 48150.

**Q. In what capacity are you employed?**

A. I am employed as Principal Mechanical Engineer for Consumers Energy Company ("Consumers Energy" or the "Company").

**Q. What is your educational background?**

A. I earned a Bachelor of Science in Mechanical Engineering from the University of Michigan – Dearborn. I am a licensed engineer in the state of Michigan.

**Q. What have your job responsibilities entailed with Consumers Energy?**

A. I began working for Consumers Energy in 2009 on the Facilities Engineering and Design Team. In 2016, I accepted the Assessment Planning Engineer role in the Transmission Integrity Management Program ("TIMP"). I am currently in this same role. The role entails managing the TIMP work plan, aligning that plan with both federal regulation and risk prioritization, selection of assessment methodology, and long term financial planning.

**Q. Please summarize your experience with Probabilistic and Relative risk models.**

A. I have been working with the risk models utilized by the Company since I started in this role in 2016. I am responsible for the post-modeling results analysis and work plan alignment. I worked with the relative risk model through 2022 and then moved to working with the current Transmission Probabilistic Risk Model upon the retirement of the relative model.

**Q. Please summarize your experience with the use of, administration, and development of the Company's Transmission Probabilistic Risk Model.**

A. I was one of the supporting team members from the beginning of the Transmission Probabilistic Risk Model adoption. I worked on the team which selected the vendor and model as well as helping to establish the Company's requirements for the project. I work with the Company's risk engineer during the data upload process, through the modeling process, and support and develop most of the post modeling analytics for work planning alignment.

**Q. Have you previously testified before the Michigan Public Service Commission ("MPSC" or the "Commission")?**

A. No, I have not.

**Q. Are you sponsoring any exhibits?**

A. Yes. I am sponsoring the following exhibit:

| | |
|---|---|
| Exhibit A-157 (BMS-1) | Response to Discovery Requests U21806-MNSC-CE-80, and U-21806-MNSC-CE-218 through 285. |

**Q. Were these exhibits prepared by you or under your direction or supervision?**

A. Yes.

**Q. What is the purpose of your rebuttal testimony?**

A. The purpose of my rebuttal testimony is to provide rebuttal testimony concerning proposals around the inclusion of cost effective calculations in the Company's risk modeling brought forth by Michigan Environmental Council ("MEC") and Sierra Club ("SC") (collectively, MEC) witness Dr. Sol deLeon.

## I. MEC WITNESS DELEON

**Q. Beginning on page 28, line 6, through page 42, line 6 of her direct testimony, MEC witness deLeon discusses risk modeling and cost-effectiveness to maximize safety impacts of ratepayer expenditures. Do you have an overall comment to make concerning her analysis?**

A. Yes, I do. The Company provided to MEC in discovery request U21806-MNSC-CE-0080 the uses and limitations of the Company's current risk models. I am including that response as Exhibit A-157 (BMS-1). As stated in her direct testimony, the Company has a probabilistic risk model in place for certain transmission assets and is in the process of making use of a probabilistic risk model on more assets in the future. Overall, the Company agrees with Dr. deLeon that they are a valuable tool. However, the fundamental problem with Dr. deLeon's analysis and recommendation is her lack of acknowledgment of the nature and limitations of the Company's current Transmission Probabilistic Risk Model and risk models in general.

**Q. At page 29 of her direct testimony, MEC witness deLeon discusses how utilities can utilize probabilistic risk models and calculate the cost effectiveness of various safety investments. Do you agree with her assessment?**

A. No, I do not. The Transmission Probabilistic Risk Model was developed for the TIMP with the purpose of calculating the total risk of an asset, the threats of which are listed in ASME B31.8S, which are driving that risk, and the consequence of a failure (nine different failure modes) at any location along those pipe assets. The work plan developed within TIMP first must comply with federal regulation for assessment compliance dates, assessment methodology, and remediation. The plan is built first to comply with the

assessment compliance dates and then prioritized by the results from the risk model. Any cost analysis must be done outside the model and would require substantial further development of the model, using Artificial Intelligence to predict the future repairs, where they are, how many, and the cost of remediation. That functionality is not likely to be available in the near future.

**Q. Can you explain the annual time frame cadence of the risk model?**

A. Yes, I can. The probabilistic risk model is run once per year. The data Extract, Transformation, and Load ("ETL") process takes up to 90 days to complete and commences in the first quarter of the year. This is the Company's process of updating the data information on the transmission system in preparation for the Company's vendor to upload into their software. After this is completed, the model requires up to three months to configure and then perform the analysis on the vendor servers. Results are returned to the Company during the third quarter. Those results are then reviewed in the Geospatial Information System, and other Company systems, and a thorough quality assurance review is performed by Company subject matter experts ("SMEs"). The risk model results are targeted for acceptance for use by the fourth quarter and then the TIMP work plan is adjusted based on findings from the model. The work plan is prioritized by compliance with federal regulation and by risk. The TIMP work planning engineers next selects an assessment methodology, which is the process or technology utilized to assess the threats on the segment. The federal code is prescriptive as to which methods can be utilized to assess each threat and options include Direct Assessment ("DA"), In-Line Inspections ("ILI"), and Pressure Testing. It is well known in the industry that some methodologies provide greater risk reduction than others. ILI is generally regarded as the most effective

method of assessing threats on a pipe asset. The Company utilizes ILI where feasible and supplements with DA where a segment is not ILI capable. Hydrostatic Pressure Testing is not typically utilized by the Company because it creates environmentally hazardous waste to dispose of, is very costly, and provides no information about the defects present on the segment.

Upon completion of the inspection, an assessment of the results is performed and dig locations are selected. The remediation team uncovers the pipe segment and performs a field inspection of the defect, and a decision is made as to the best option for remediation. Options include a cut-out, a mechanical sleeve, or a recoat and return to service. Customer impact, system resilience, reassessment intervals/methodology, permanent verses temporary repair, and cost are considered when determining which mitigation to implement. This occurs in the summer and fall of the year.

Results from the inspection, assessment, and remediation are gathered and prepared for the ETL process for the next risk model run in the last quarter of the year. The modeling process is performed, and when results are returned, the Company can analyze the actual reduction in risk achieved based on the actions performed. Part of the TIMP requirements is to ensure that the work performed is effectively lowering the risk for each segment. Pipe assets which continue with favorable risk trending support that the TIMP work is effective for that asset. An asset with trending that is less favorable can then be investigated for other work such as retirement, replacement, pressure lowering, or other operational changes. Design options for these projects consider cost, effectiveness, deliverability, system resilience, and customer impact.

The probabilistic risk model is designed to calculate current state risk. To calculate mitigation effectiveness, the model requires the data collected post project to perform the analysis. This data is not available during the design phase so the model cannot calculate a mitigation effectiveness value. This is not unique to the model used by the Company. What some models use for an effectiveness value is industry averages. These values are not accurate for analysis on individual assets which leads to over or understating of mitigation effectiveness. The Company uses the model to understand the risk and threats to an asset and then selects the methodology to mitigate that threat based on industry knowledge, cost, system reliability, and customer impact.

**Q. Does the Company compare risk results to understand the impact of work performed?**

A. Yes, it does. The Company compares previous year risk results to current year risk results to understand the full impact of work performed in the previous year. Multiple years of risk cannot be compared at this point because of the migration from a relative to a new probabilistic risk model. Comparing long-term risk results for overall reduction values is not appropriate with integrity related asset models because the threats in the model are time dependent. Upon the completion of a project and the data being loaded into the model from that point forward the risk due to time dependent threats increases until another mitigation is performed. This aligns with federal regulation requiring the assessment of these assets on a prescriptive interval.

**Q. Beginning on page 28, line 9, through page 29, line 2 of her direct testimony, MEC witness deLeon discusses the definition of cost-effectiveness in relation to safety related programs. Do you agree with her analysis?**

A. No, I do not. Cost-effectiveness and risk reduction are just two of several factors that need to be considered when evaluating various mitigative measures. Additional items like customer impact, system resilience, reassessment intervals/methodology, and permanent verses temporary repair all need to be considered when determining which mitigation to implement.

**Q. Does the Company undertake efforts to ensure its project spending is reasonable?**

A. Yes, it does. In the Pipeline Integrity Program, which is primarily O&M expense, the Company competitively bids materials, sets up multi-year fixed rate contracts to ensure lower costs, and utilizes one contractor for multiple projects in order to lower mobilization/demobilization costs. Additionally, for capital projects being conducted for other purposes outside of the federally mandated Pipeline Integrity Program, (i.e., for customer requested work and to ensure reliability and deliverability), the Company also competitively bids materials and contractors and has a system planning group that aligns projects within common time frames to limit outages, blowdowns, and methane emissions.

**Q. At page 29 of her direct testimony, Dr. deLeon proposes how a utility could calculate the cost-effectiveness of various safety investments. Is this an effective way to calculate cost-effectiveness?**

A. No, not for the Company, nor the models the Company is familiar with. What some models use for an effectiveness value is industry averages. These values are not accurate for analysis on individual assets which leads to over or understating of mitigation

effectiveness. The Company's model is used to understand the risk and threats to an asset and then selects the methodology to mitigate that threat based on industry knowledge, cost, system reliability, and customer impact. For Pipeline Integrity inspections, the Company has a seven-year mandated inspection cycle, so even in the case of a low risk scored project, the Company must perform the work to comply with regulations.

**Q. Could cost-effectiveness be included in the Company's probabilistic risk model in the manner suggested by MEC witness deLeon?**

A. It could not. The risk model is intended to provide insight into threats on the system and is not intended to be a financial evaluation tool. Further, it is neither prudent nor practical for the reasons stated above.

**Q. Does the Company agree with Dr. deLeon, on page 30 of her direct testimony, that the value in risk modeling is to "allow stakeholders to examine the level of risk reduction expected from Consumers' proposed remediations, the cost to achieve this, and an ability to assess alternatives that could better maximize risk reduction and minimize costs."?**

A No, it does not. The Transmission Probabilistic Risk Model was developed with the purpose of calculating the total risk of an asset, the threats listed in ASME B31.8S which are driving that risk, and the consequence of a failure (nine different failure modes) at any location along those pipe assets. The model can help provide insight into the threats on segments as a tool to validate the correct inspection methods and mitigative measures are part of the mandated pipeline assessments. This tool was not intended to be a financial tool used to evaluate project selection and does not have the capabilities or the years of historical data to do so with meaningful results. The risk model is an important tool used

to ensure we take the appropriate actions from a pipeline integrity perspective to provide safe and reliable gas service.

**Q. On page 30, line 15 of her direct testimony, MEC witness deLeon discusses the relationship between risk modeling, cost effectiveness, and the energy transition. Considering the "energy transition," she argues that the Company should minimize spending on irreversible and long-lived investments. Does the Company agree with these ideas?**

A. No, it does not. Please see the rebuttal testimony of Company witness Neal P. Dreisig, describing how the Company's gas system infrastructure is becoming more critical.

**Q. Beginning at page 31, line 16, of her direct testimony, MEC witness deLeon provides examples of how utilities use risk modeling and cost-effectiveness in their decision-making. Are these examples relevant to this case?**

A. No, they are not. As described in Dr. deLeon's testimony concerning Washington Gas, the ranking is *a basic prioritization* and then may *be modified* with SME input based upon various factors. Further, Washington Gas only utilizes their model on distribution assets and primarily for that utility's distribution main replacement program, which is vastly different from utilization of the probabilistic risk model on transmission assets as done by Consumers Energy. As I have previously stated, the probabilistic risk model used by the Company indicates the threat, consequence, and risk of the asset allowing companies to prioritize the integrity projects. Cost-effectiveness and Risk Spend Efficiency ("RSE") would be calculated outside the model. It is worth noting that enhanced risk modeling, integrity measures, and stricter enforcement of pipeline regulations were a result of

incidents like that at San Bruno. Cost-effectiveness is not a part of the Pipeline and Hazardous Materials Safety Administration's recommendation around risk modeling.

**Q. Do these examples demonstrate that risk modeling and cost-effectiveness should be adopted in the manner proposed by Dr. deLeon?**

A. No, they do not. I have described the purpose and limitations of probabilistic risk models. There are other limitations with risk modeling. This was acknowledged in a presentation concerning risk modeling for utility investments by Synapse Energy.[1] These include the need for a history of data collection (which the Company does not currently possess), the sharing of confidential and critical information, the fact that they do not directly address affordability, and that they do not address what is an acceptable level of risk. In the Company's case, given the recent and emerging implementation of probabilistic risk models, there is not any significant history. Further, there is an inherent vulnerability and security risk with providing this type of information in the public domain. Not to mention the financial and reputational liability the Company could face were it not to address a known threat for financial reasons.

**Q. Beginning on page 34, lines 6 through 16 of her direct testimony, MEC witness deLeon discusses her understanding of relative risk models compared to probabilistic models. Do you agree with her assessment?**

A. No. The definitions used by Dr. deLeon are blending multiple types of models together as opposed to properly describing each type of model. The first definition concerning a relative model is not accurate. The description given is that of a qualitative model which

[1] https://www.nasuca.org/wp-content/uploads/2023/03/Risk-Presentation_Eric Borden_Synapse_NASUCA_6.18.23.pdf

does not calculate a numerical score for likelihood, consequence, or risk. A relative model can be qualitative, semi-quantitative, or quantitative. The defining characteristic of a relative model is that the failure calculation is a likelihood and not a probability. The relative model can use these numerical scores to compare one asset within the model to another or to the system as a whole which is a relative comparison. A probabilistic model calculates a probability of failure based on the confidence of the data provided. This probability is independent of anything else within that model and does not rely on being compared to other assets to determine the severity of the threat or the resulting risk. Neither of these models inherently calculates mitigation effectiveness values but instead are run with new data to calculate a new risk score after project completion. Models that do calculate mitigation effectiveness do so using industry averages that make individual asset evaluation for risk mitigation and cost benefit unreliable.

**Q. Beginning on page 40, lines 5 through 8 of her direct testimony, MEC witness deLeon recommends that the Company report on a regular basis transmission-level projects that demonstrate how Consumers Energy utilizes cost-effectiveness, where applicable, to maximize safety impacts for the ratepayer dollars spent. Calculations and assumptions should be available to stakeholders upon request. Do you agree with this recommendation?**

A. No, I do not. I have explained above how the Company uses the probabilistic risk model and how the other projects in the transmission programs are selected. The Company has provided an explanation as to why it is not practical to provide the results of the relative risk model along with other information pertaining to the model to MEC in discovery

requests that are included in Exhibit A-157 (BMS-1). The Company offered MEC an opportunity to review the Company's models. They did not respond to this offer.

**Q. On page 41, lines 1 and 2, MEC witness deLeon recommended that the Company's future rate case applications should utilize probabilistic risk modeling and cost-effectiveness calculations to a much greater extent for all asset classes. Is this possible?**

A. No, it is not. As acknowledged by Dr. deLeon, the Company is in the process of rolling out probabilistic risk modeling for the different asset classes. Developing the models is a tremendous undertaking and the Company will in all likelihood not have probabilistic models for all asset classes prior to its next rate case. The Company is developing a model for storage wells which it expects to begin utilizing in 2025 and the Company expects to develop a probabilistic distribution asset risk model by 2027. However, as I have explained the problems with cost-effectiveness calculations and further, these models are not developed with cost-effectiveness capabilities.

**Q. Beginning on page 41, lines 1 through 21 of her direct testimony, MEC witness deLeon makes recommendations concerning future rate case applications. Do you agree with this recommendation?**

A. No, I do not. As I have explained above, the Company will not have probabilistic risk models on all assets prior to its next rate case filing. Further Dr. deLeon's recommendation that the Company calculate the risk reduction, cost, and RSE for all of its expenditures is not possible for the reasons I have stated above. The Company has and will continue to provide robust rate case filings that comply with all MPSC filing requirements, which do not include the proposals made by MEC. Dr. deLeon's recommendations are not possible

with the risk model currently in use and the results would not be obtainable. I have described above how the Company uses the current model. These recommendations would be unduly burdensome and unnecessary as the Company currently operates the system in a safe and effective manner taking into consideration safety and affordability.

**Q. Beginning on page 41, line 13, MEC witness deLeon suggests the Commission should order the Company to provide an estimate of the impact prior year's expenditures have had to reduce risk on the system. Do you agree with this recommendation?**

A. No, I do not. As I have explained above, the Company compares previous year risk results to current year risk results to understand the full impact of work performed in the previous year. Multiple years of risk cannot be compared at this point because of the migration from a relative to a new probabilistic risk model. Comparing long-term risk results for overall reduction values is not appropriate with integrity related asset models because the threats in the model are time dependent. Upon the completion of a project and the data being loaded into the model from that point forward the risk due to time dependent threats increases until another mitigation is performed.

**Q. Does this conclude your rebuttal testimony?**

A. Yes, it does.

MR. RUSZKIEWICZ: The Company's next witness is Brian J. VanBlarcum. And based on stipulation of the parties, the Company moves to bind in the direct testimony of Mr. VanBlarcum, which consisted of a cover page plus eight pages of prefiled testimony. The Company also moves to admit two exhibits, it looks like. Those exhibits are labeled as A-99 and A-100. Thank you.

JUDGE VARCHETTI: All right. Are there any objections to binding in the testimony, the direct testimony of Mr. VanBlarcum or any of the associated exhibits?

Hearing none, then, the testimony of Mr. VanBlarcum is admitted, as are the associated exhibits.

MR. RUSZKIEWICZ: Thank you, Your Honor.

(Direct Testimony bound in)

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

| | | |
|---|---|---|
| In the matter of the application of **CONSUMERS ENERGY COMPANY** for authority to increase its rates for the distribution of natural gas and for other relief. | ) ) ) ) ) | Case No. U-21806 |

**DIRECT TESTIMONY**

**OF**

**BRIAN J. VANBLARCUM**

**ON BEHALF OF**

**CONSUMERS ENERGY COMPANY**

December 2024

**Q. Please state your name and business address.**

A. My name is Brian J. VanBlarcum, and my address is One Energy Plaza, Jackson, Michigan 49201.

**Q. By whom are you employed?**

A. I am employed by Consumers Energy Company ("Consumers Energy" or the "Company").

**Q. What is your position with Consumers Energy?**

A. I am a Tax Director in the Company's Corporate Tax Department.

**Q. Please briefly describe your educational background.**

A. I am a graduate of Western Michigan University where I earned a Bachelor of Business Administration degree in Finance.

**Q. Please describe your business experience.**

A. I started with the Company in 2004 as a General Accounting Analyst with the Company's Property Accounting team. In 2019, I was appointed to my current position as Tax Director with the Company's Corporate Tax Department.

**Q. Are you a certified assessor?**

A. I am a Michigan Certified Assessing Officer certified by the State of Michigan's State Tax Commission and a member of the Michigan Assessors Association.

**Q. What are your responsibilities as Tax Director?**

A. I am responsible for the administration of the Company's real and personal property taxes. This includes: (i) managing the Company's self-declaration of personal property located within the state of Michigan; (ii) overseeing property tax matters concerning the Company's land, generating sites, and other real property; and (iii) supervising tax payments to approximately 1,500 taxing authorities. I am also responsible for the

calculation of federal and state tax depreciation related to the Company's fixed assets and the associated deferred income taxes.

**Q. Have you previously testified before the Michigan Public Service Commission ("MPSC" or the "Commission")?**

A. Yes, I sponsored testimony in the following cases:

- Gas Rate Case No. U-15506;
- Electric Rate Case No. U-15645;
- Electric Rate Case No. U-16191;
- Gas Rate Case No. U-16418;
- Electric Rate Case No. U-17087;
- Electric Rate Case No. U-17735;
- Gas Rate Case No. U-17882;
- Electric Rate Case No. U-17990;
- Gas Rate Case No. U-18124;
- Electric Rate Case No. U-18322;
- Gas Rate Case No. U-18424;
- Electric Rate Case No. U-20134;
- Gas Rate Case No. U-20322;
- Gas Rate Case No. U-20650;
- Electric Rate Case No. U-20697;
- Gas Rate Case No. U-21148;
- Electric Rate Case No. U-21224;
- Gas Rate Case No. U-21308;

- Electric Rate Case No. U-21389;
- Gas Rate Case No. U-21490; and
- Electric Rate Case No. U-21585.

**Q. What is the purpose of your direct testimony in this proceeding?**

A. My direct testimony identifies the Property Tax Rate for the test year (12 months ending October 31, 2026) and explains how the rate was derived. I am also supporting the amount of test year excess deferred federal income taxes being returned to gas customers as a result of the Tax Cuts and Jobs Act of 2017 ("TCJA") and the Commission's September 26, 2019 Order in the Company's Calculation C Case No. U-20309.

**Q. Have you prepared any exhibits to accompany your direct testimony?**

A. Yes. I am sponsoring:

| | |
|---|---|
| Exhibit A-99 (BJV-1) | Development of the Property Tax Rate for the Test Year; and |
| Exhibit A-100 (BJV-2) | Amortization of Excess Deferred Federal Income Taxes for the Test Year and Tax Reform Regulatory Liability & Amortization. |

**Q. Were these exhibits prepared by you or under your supervision?**

A. Yes.

**<u>Development of the Property Tax Rate for the Test Year</u>**

**Q. What is the Property Tax Rate for the test year?**

A. As indicated on Exhibit A-99 (BJV-1), page 1, line 16, the Property Tax Rate for the test year is 0.013998859.

**Q. How did you calculate the Property Tax Rate for the test year?**

A. The Property Tax Rate for the gas business was calculated using the Company's prorated Gas Property Tax Expense in Exhibit A-99 (BJV-1), page 1, line 10, divided by the total

of the 2025 estimated year-end plant-in-service in Exhibit A-99 (BJV-1), page 1, line 11, plus one-half of the estimated 2025 Construction Work in Progress in Exhibit A-99 (BJV-1), page 1, line 14.

**Q. What is included in the Gas Property Taxes Paid – 2025 Estimate on Exhibit A-99 (BJV-1), page 1, line 1?**

A. The Consumers Energy 2025 taxes paid of $196.8 million on behalf of the gas portion of the business represents estimated property taxes to be paid in 2025.

**Q. What is included in the Gas Property Taxes on 2025 Plant Investment on Exhibit A-99 (BJV-1), page 1, line 2?**

A. The $17.2 million increase is the estimated property taxes on the 2025 net additions that will be included in the 2026 property tax liability. This is calculated by taking the capital additions, less retirements, times the first year State Tax Commission multiplier table value to recognize a depreciation allowance, which is then multiplied by the statutory reduction of 50% of true cash value to get the assessed value, then multiplied by Consumers Energy's composite millage rate of 50.1693 to obtain the estimated tax amount. This calculation is shown on Exhibit A-99 (BJV-1), page 2, line 9.

**Q. What is included in the Gas Property Taxes on Real Property Taxable Value Increases – Inflation on Exhibit A-99 (BJV-1), page 1, line 3?**

A. The $0.1 million increase for the Real Property Taxable Value relates to the Michigan Constitution of 1963, Article IX, Section 3, allowing local assessors to raise real property taxable values by the lesser of 5% or the Consumer Price Index ("CPI"). For 2026, the Company's property tax model assumes a CPI rate of 2.5%. This calculation is shown on Exhibit A-99 (BJV-1), page 3.

**Q. What is the result of including the Gas Property Taxes on 2025 Plant Investment and the Gas Property Taxes on Real Property Taxable Value Increase on the estimated 2026 property tax amount paid by the gas business?**

A. The result of including these additional items is an estimated 2026 property tax amount to be paid for the gas business of $214.1 million as shown on Exhibit A-99 (BJV-1), page 1, line 4.

**Q. How is this paid amount converted to an expense amount?**

A. Since the Company expenses property taxes based on the fiscal year of the taxing authorities, 50.0% of the 2025 estimated gas property tax payments for Consumers Energy is added to the 2026 estimated gas payments since that amount will be expensed in 2026, while subtracting 50.0% of the 2026 estimated gas payments that will be expensed in 2027, arriving at a total 2026 property tax expense of $205.4 million as shown on Exhibit A-99 (BJV-1), page 1, line 7.

**Q. What is the next step in calculating the tax rate for the test year?**

A. For the test year, property tax expense was prorated for the period November 1, 2025 through October 31, 2026 using a monthly budgeted sales percentage applied to the 2025 and 2026 estimated annual property tax expense amounts. The result of factoring property tax expense monthly for the test year is a prorated Gas Property Tax Expense of $201.2 million. The Prorated Property Tax Expense for the test year is divided by the 2025 estimated year-end plant-in-service plus one-half of 2025 Estimated Construction Work in Progress to arrive at an average tax rate of 0.013998859.

**Amortization of Excess Deferred Federal Income Taxes for the Test Year**

**Q. On September 26, 2019, the Commission issued an Order in the Company's Calculation C Case No. U-20309. What specific issues did the September 26, 2019 Order in Case No. U-20309 address?**

A. The Commission's September 26, 2019 Order in the Company's Calculation C Case No. U-20309 authorized the amount and time period under which the Company will refund to gas customers $451,588,000 of excess deferred federal income taxes as a result of the TCJA lowering the corporate income tax rate from 35% to 21%. As part of the settlement terms in Case No. U-21148, the Commission approved an adjustment to reduce this amount by $4,174,259 to correct an overstatement of the TCJA remeasurement. The Commission authorized three different amortization periods: (i) Protected plant balances over an amortization period determined using the average rate assumption method ("ARAM"), (ii) Non-Protected plant balances amortized over 44 years, and (iii) Unprotected non-plant balances amortized over 10 years. Exhibit A-100 (BJV-2), page 2, referenced as Exhibit A-6 (SBM-4) in Case No. U-20309, provides the projected annual amortization of these balances based on the periods approved by the Commission.

**Q. What impact did the settlement terms in Case No. U-20650 have on the unprotected non-plant balance?**

A. The settlement in Case No. U-20650 accelerated the amortization of the remaining unprotected, non-plant balance to the period October 1, 2021 through September 30, 2022. As of October 1, 2022, the regulatory liability balance has been fully refunded to customers. Therefore, no amortization has been included in this case.

**Q. What additional amount of excess deferred taxes related to the TCJA has the Company proposed to charge to customers in this case?**

A. As shown on Exhibit A-100 (BJV-2), page 1, line 22, the Company has proposed to charge an additional $2,540,000 of excess deferred taxes ($3,406,000 of regulatory asset after gross-up for taxes) in this case. This amount represents the Company's regulatory asset recorded as of year-end 2022 which was calculated as the difference between the actual amount of excess deferred taxes for the year and the estimated amount included in rates. The Company's most recently filed report to the Case No. U-20309 docket, which calculates the $3,406,000 regulatory balance, is included as Exhibit A-100 (BJV-2), page 3.

**Q. Based on the Commission's September 26, 2019 Order in Case No. U-20309 and the additional amount described above, what amount of excess deferred federal income tax has the Company proposed to return to customers in this case?**

A. Exhibit A-100 (BJV-2), page 1, provides a calculation of the test year excess deferred federal income taxes included in this case based on the periods approved by the Commission in Case No. U-20309. Overall, the Company reduced Federal Income Tax Expense for the test year by $2.043 million to reflect the amortization periods and amounts discussed above. This amount is shown on Company witness Heather L. Rayl's Exhibit A-13 (HLR-45), Schedule C-8, lines 43, 47, and 48 as TCJA Tracker – U-20309, TCJA Amortization – ARAM, and TCJA – Non ARAM.

**Q. Are the excess deferred federal income tax amounts refunded to gas customers in the test year estimates or actuals?**

A. The amounts included in this case are estimates as the Commission's September 26, 2019 Order in Case No. U-20309 requires an annual reconciliation of the actual amount of excess

deferred federal income tax in a given year and the estimated amount included in rates. The Company will file this reconciliation in the Case No. U-20309 docket by March 31 of each year.

**Q. Does this conclude your direct testimony?**

A. Yes.

MR. RUSZKIEWICZ: As mentioned by my colleague, the Company also has an exhibit labeled as A-158, which is a hearing room exhibit that was presented in lieu of cross of Mr. Coppola, and with that, Consumers completes its presentation of testimony and exhibits for the purpose of binding them into the record. Thank you.

JUDGE VARCHETTI: Thank you. All right. We will go off the record for just a second, Dawn.

(At 10:49 AM, recess was taken)

(At 10:50 AM, proceedings resume)

JUDGE VARCHETTI: All right. We are now back on the record.

And it was my understanding that the Company requested admission of Exhibit A-158. Were there any objections to the admission of Exhibit A-158?

Hearing none, then, Exhibit A-158 is admitted, and that completes the Company's evidentiary presentation.

And we will move on, then, with the evidentiary presentation of the Attorney General.

MS. GILL: Thank you, Your Honor.

By stipulation of the parties, the Attorney General moves to bind in the prefiled revised direct testimony of Sebastian Coppola. There -- there are both public and confidential versions of Mr. Coppola's

testimony, and both are 198 pages long, and consists of a cover page, a table of contents, and then followed by 196 pages of questions and answers. An Appendix A with Mr. Coppola's qualifications and experience was filed with his direct testimony and should also be bound into the record.

The Attorney General also moves for the admission of Mr. Coppola's prefiled exhibits. Mr. Coppola is fostering prefiled exhibits that include a mix of public, confidential, and revised exhibits and with his revised direct testimony, so I will try to clarify the nature of the exhibits as I go down the list.

Okay. Exhibits AG-1 through AG-27 are public exhibits. Exhibit AG-28 is a confidential exhibit. Exhibits AG-29 through AG-33 are public exhibits. Exhibit AG-34 is a revised confidential exhibit. Exhibit AG-35 -- excuse me. Did I say AG-35 above or AG-34? AG-34 is a revised confidential exhibit. Exhibit AG-35 is a confidential exhibit. Exhibit AG-36 is a public exhibit. Exhibit AG-37 is a confidential exhibit. Exhibits AG-38 through AG-55 are public exhibits. Exhibit AG-56 is a revised confidential exhibit. And then the following are also public exhibits, AG-57 through AG-60, AG-63, AG-65 through AG-67, with Exhibit AG-67 being a revised exhibit.

And just to clarify for the record,

former Exhibits AG-61, AG-62, and AG-64 have been withdrawn, and therefore, the Attorney General is not moving for their admission.

JUDGE VARCHETTI: Thank you. So are there any objections to admitting the revised direct testimony of Mr. Coppola, which has both public and confidential versions, as well as all of the associated exhibits just named by Ms. Gill?

I am hearing no objections, so in that case, the testimony is bound into the record, and the associated exhibits are admitted.

(Revised Direct Testimony and Appendix A bound in)

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

MPSC Case No. U-21806

| | |
|---|---|
| In the matter of the application of | ) |
| CONSUMERS ENERGY COMPANY | ) |
| for authority to increase its rates for the | ) |
| distribution of natural gas and other relief | ) |

**PUBLIC**

# Revised Direct Testimony
# And Exhibits
# of
# Sebastian Coppola

**On behalf of**

**Attorney General Dana Nessel**

~~April~~ May 23, 2025

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VERITEXT LEGAL SOLUTIONS

# I. Introduction

**Q. PLEASE STATE YOUR NAME, OCCUPATION, AND ADDRESS.**

A. My name is Sebastian Coppola. I am an independent business consultant. My office is located at 5928 Southgate Rd., Rochester, Michigan 48306.

**Q. PLEASE SUMMARIZE YOUR PROFESSIONAL QUALIFICATIONS.**

A. I am a business consultant specializing in financial and strategic business issues in the fields of energy and utility regulation. I have more than forty years of experience in public utility and related energy work, both as a consultant and utility company executive. I have testified in several regulatory proceedings before the Michigan Public Service Commission (MPSC or Commission) and other regulatory jurisdictions. I have prepared and/or filed testimony in rate case proceedings, revenue decoupling reconciliations, gas conservation programs, Gas Cost Recovery (GCR) cases and Power Supply Cost Recovery (PSCR) cases. As accounting manager and later financial executive for two regulated gas utilities with operations in Michigan and Alaska, I have been intricately involved in regulatory proceedings related to gas cost recovery cases, gas purchase strategies, rate case filings and power plant cost analysis. I have also supported other witnesses in testimony before the MPSC in various rate settings and other regulatory proceedings.

**Q. PLEASE LIST SOME OF THE MORE RECENT CASES YOU HAVE PARTICIPATED IN BEFORE THE MPSC AND OTHER REGULATORY AGENCIES.**

A. Here is a partial list of the most recent regulatory cases in which I have participated in the last two years:

- Filed testimony on behalf of the Michigan Attorney General in Michigan Gas Utilities Corporation (MGUC) 2023-2024 GCR reconciliation in case No. U-21274.
- Filed testimony on behalf of the Michigan Attorney General in DTE Electric Company (DTEE) 2023 PSCR reconciliation in case No. U-21260.
- Filed testimony on behalf of the Michigan Attorney General in Consumers Energy Company (CECo) 2023-2024 GCR reconciliation in case No. U-21270.
- Filed testimony on behalf of the Michigan Attorney General in SEMCO Energy Gas Company (SEMCO) 2023-2024 GCR plan reconciliation in case No. U-21278.
- Filed testimony on behalf of the Michigan Attorney General in CECo 2023 PSCR reconciliation in case No. U-21258.
- Filed testimony on behalf of the Michigan Attorney General in CECo 2024 electric rate case U-21585 on several issues, including operation and maintenance expenses, capital expenditures, cost of capital, and other items.
- Filed testimony on behalf of the Michigan Attorney General in DTEE 2024 electric rate case U-21534 on several issues, including operation and maintenance expenses, capital expenditures, cost of capital, and other items.
- Filed testimony on behalf of the Michigan Attorney General in the Upper Peninsula Power Company (UPPCO) 2024 gas rate case U-21555 on several issues, including operation and maintenance expenses, capital expenditures, cost of capital, and other items.
- Filed testimony on behalf of the Michigan Attorney General in MGUC 2024 gas rate case U-21540 on several issues, including operation and maintenance expenses, capital expenditures, cost of capital, and other items.
- Filed testimony on behalf of the Michigan Attorney General in SEMCO Energy Gas Company (SEMCO) 2023-2024 GCR plan in case No. U-21277.
- Filed testimony on behalf of the Michigan Attorney General in DTE Gas Company (DTE Gas) 2024 gas rate case U-21291 on several issues, including sales, operation and maintenance expenses, capital expenditures, cost of capital, and other items.
- Filed testimony on behalf of the Michigan Attorney General in DTE Gas 2022-2023 GCR reconciliation in case No. U-21065.

- Filed testimony on behalf of the Michigan Attorney General in CECo 2023 gas rate case U-21490 on several issues, including sales, operation and maintenance expenses, capital expenditures, cost of capital, and other items.
- Filed testimony on behalf of the Michigan Attorney General in DTM Michigan Lateral Company (DMLC) 2023 Act 9 Transportation Service rate update in case No. U-21525.
- Filed testimony on behalf of the Michigan Attorney General in DTE Electric Company (DTEE) 2022 PSCR reconciliation in case No. U-21051.
- Filed testimony on behalf of the Michigan Attorney General in Michigan Gas Utilities Corporation (MGUC) 2022-2023 GCR reconciliation case No. U-21067.
- Filed testimony on behalf of the Michigan Attorney General in Consumers Energy Company (CECo) 2022 PSCR reconciliation in case No. U-21049.
- Filed testimony on behalf of the Michigan Attorney General in the Indian Michigan Power Company's 2023 electric rate Case U-21461 on several issues, including sales, operation and maintenance expenses, capital expenditures, cost of capital, and other items.
- Filed testimony on behalf of the Michigan Attorney General in DTE Gas Company (DTE Gas) 2023-2024 GCR plan in case No. U-21271.
- Filed testimony on behalf of the Michigan Attorney General in CECo 2023-2024 GCR plan in case No. U-21269.
- Filed testimony on behalf of the Michigan Attorney General in CECo 2023 electric rate Case U-21389 on several issues, including operation and maintenance expenses, capital expenditures, cost of capital, and other items.
- Filed testimony on behalf of the Michigan Attorney General in SEMCO Energy Gas Company (SEMCO) 2023-2024 GCR plan in case No. U-21277.
- Filed testimony on behalf of the Michigan Attorney General in DTE Electric Company (DTEE) 2023 rate Case U-21297 on several issues, including operation and maintenance expenses, capital expenditures, cost of capital, and other items.
- Filed testimony on behalf of the Michigan Attorney General in MGUC 2023-2024 GCR plan in case No. U-21273.
- Filed testimony on behalf of the Michigan Attorney General in CECo 2022 gas rate Case U-21308 on several issues, including sales revenues, operation and maintenance expenses, capital expenditures, cost of capital, and other items.

Appendix A elaborates further on my qualifications in the regulated energy field.



VERITEXT LEGAL SOLUTIONS

**Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?**

A. I have been asked by the Michigan Department of Attorney General to perform an independent analysis of Consumers Energy Company's (CECo or the Company) gas rate case filing in Case No. U-21806. This testimony presents a report of that analysis with related recommendations.

**Q. WHAT TOPICS ARE YOU ADDRESSING IN YOUR TESTIMONY?**

A. I am addressing the following major topics in this case:

1. The level of proposed rate base and capital expenditures
2. The amount of working capital
3. The Company's cost of capital
4. Adjustments to forecasted transportation volumes and related revenues for the projected test year
5. The level of operations and maintenance expenses
6. Depreciation and property tax adjustments
7. Rate design issues
8. Deferral of certain costs proposed by the Company.

The absence of a discussion of other matters in my testimony should not be taken as an indication that I agree with those aspects of CECo's rate case filing. The narrow focus of my testimony is, instead, a consequence of focusing on select issues within the available resources.

**Q. IS YOUR TESTIMONY ON THESE TOPICS ACCOMPANIED BY EXHIBITS?**

A. Yes. I am sponsoring the following exhibits, which were either prepared by me or under my direct supervision:

1. Exhibit AG-1 CMS Energy Investor Presentations
2. Exhibit AG-2 New Service Connections
3. Exhibit AG-3 Asset Relocations-Civic
4. Exhibit AG-4 Asset Relocations-Reimbursable
5. Exhibit AG-5 Regulatory Compliance MAOP projects
6. Exhibit AG-6 PHMSA Rule on MAOP
7. Exhibit AG-7 EIRP Miles Retired, Installed and Costs
8. Exhibit AG-8 EIRP Large Projects Development Phase
9. Exhibit AG-9 EIRP Completion Extension
10. Exhibit AG-10 Material Condition Non-Modeled Projects
11. Exhibit AG-11 Vintage Services Replacement Program
12. Exhibit AG-12 LDAR Rule and Advanced Methane Detection
13. Exhibit AG-13 ECAP Cap Ex Projects
14. Exhibit AG-14 Utility Network IT Project
15. Exhibit AG-15 Transmission Pipeline Integrity Projects
16. Exhibit AG-16 Transmission MAOP Projects
17. Exhibit AG-17 Transmission Asset Relocation projects
18. Exhibit AG-18 Transmission Field Measurement Projects
19. Exhibit AG-19 Transmission Pipeline Deliverability Projects
20. Exhibit AG-20 Transmission Citygate Stations
21. Exhibit AG-21 Transmission Remote Closure Valves
22. Exhibit AG-22 Northville Dehydration Project
23. Exhibit AG-23 Storage New Well Projects
24. Exhibit AG-24 Storage and Compression Projects
25. Exhibit AG-25 Storage and Compression Large Projects
26. Exhibit AG-26 Storage and Compression 2024 Underspent
27. Exhibit AG-27 Tracking and Traceability IT Project
28. Exhibit AG-28 CONF ERP IT Project

29. Exhibit AG-29 ERP IT Project Features
30. Exhibit AG-30 IT Servers and Equipment Replacement
31. Exhibit AG-31 IT Project Forward Web Proxy Services
32. Exhibit AG-32 IT Projects 2024 Underspent
33. Exhibit AG-33 Transportation Fleet Purchases
34. Exhibit AG-34 CONF Revised AG Capex, Rate Base, Depreciation, Property Taxes Adjust.
35. Exhibit AG-35 CONF Working Capital Adjustments Summary
36. Exhibit AG-36 Working Capital – Cash On Hand Balances
37. Exhibit AG-37 CONF W/C SAP S/4 Cloud Implementation Costs
38. Exhibit AG-38 W/C Cloud Computing Amortization Corrected
39. Exhibit AG-39 W/C Riverside Storage Field Loss Amortization
40. Exhibit AG-40 W/C Accrued Taxes
41. Exhibit AG-41 Overall Cost of Capital
42. Exhibit AG-42 Cost of Common Equity
43. Exhibit AG-43 Cost of Common Equity-DCF
44. Exhibit AG-44 Cost of Common Equity-CAPM
45. Exhibit AG-45 Cost of Common Equity-Risk Premium
46. Exhibit AG-46 Peer Group Utility and Non-Utility Business Mix
47. Exhibit AG-47 Market to Book Ratios of Peer Group
48. Exhibit AG-48 ROE Decisions by Regulatory Commissions
49. Exhibit AG-49 Cash Flow to Debt Coverage Ratio Recalculation
50. Exhibit AG-50 Peer Group ROEs
51. Exhibit AG-51 Rating Agencies Reports
52. Exhibit AG-52 Value Line Market Volatility Not Risk
53. Exhibit AG-53 Gas Sales Analysis
54. Exhibit AG-54 Transportation Revenue Adjustments
55. Exhibit AG-55 Transportation Volume Decline Not Explained
56. Exhibit AG-56 CONF Revised O&M Summary Adjustments
57. Exhibit AG-57 Distribution Pipeline Integrity, Lean Office, AMD
58. Exhibit AG-58 EIRP Training

59. Exhibit AG-59 Transmission Corrosion Control and MAOP Expense
60. Exhibit AG-60 Customer Service, Analytics and Digital
~~61. Exhibit AG-61 Revised Act 9 Transportation Volume Credits~~
~~62. Exhibit AG-62 Recalculation of Com Use and LAUF Gas Expense~~
63. Exhibit AG-63 Voluntary Separation Program Cost Savings
~~64. Exhibit AG-64 Corporate Expenses and General Activities 2021 PTY~~
65. Exhibit AG-65 Health Care Cost Savings
66. Exhibit AG-66 Incentive Compensation Operating Measures Results
67. Revised Exhibit AG-67 AG Revised Revenue Requirement

## II. SUMMARY CONCLUSIONS & RECOMMENDATIONS

**Q. PLEASE PROVIDE A SUMMARY OF YOUR CONCLUSIONS AND ANY ADJUSTMENTS TO THE COMPANY'S REVENUE DEFICIENCY CALCULATION BEFORE YOU ADDRESS EACH TOPIC IN DETAIL.**

A. The Company filed for a rate increase of $248 million. The rate increase represents an overall increase in base rates of 16% and an increase in residential base rates also of 17.6%. Including the cost of gas, the average residential gas bill would increase by approximately 12%. I have identified several cost disallowances to the Company's proposed cost levels and capital projects, that I recommend the Commission approve. As a result of these adjustments, I have determined that the Company has a revenue deficiency of $~~76.5~~ 95.6 million. It should be noted that the Company reported a revenue sufficiency (surplus) of $9.4 million in 2023. The Company also achieved a Return on Common Equity of 10.08% in 2023.[1] My conclusions and related adjustments are summarized below:

[1] Exhibit A-1, Schedule A1 and Schedule A-2.

1. I recommend a reduction in capital expenditures of ~~$563~~$533 million and a reduction of ~~$535~~ $514.7 million to rate base for the test year, including a $154 million adjustment to working capital. This reduces the Company's revenue deficiency by ~~$42.7~~$41.1 million.

2. I recommend that the Commission adopt a lower cost of capital rate of 5.97%, a capital structure with 50% equity capital and a return on common equity of 9.75%. These recommendations reduce the Company's revenue deficiency by $39.2 million.

3. I recommend higher commercial transportation gas deliveries, which increase distribution margin revenue by $1.8 million.

4. I recommend a lower level of Operations and Maintenance expenses for the test year. This reduces the Company's revenue deficiency by ~~$73.3~~$56.4 million.

5. I recommend a lower amount of depreciation expense of ~~$13.7~~$13.3 million and lower property tax expense of ~~$3.9~~$3.7 million pertaining to the lower capital expenditures and additions to plant discussed above. These adjustments reduce the revenue deficiency by the same amount.

6. I recommend that the Commission retain the residential monthly customer charge remain at $15.00.

7. I recommend that the Commission retain the General Service GS-1 monthly customer charge at $18.00.

8. I recommend that the Commission reject several of the accounting cost deferral and premature or unnecessary.

The remainder of my testimony provides further details and support to these summary conclusions and recommendations.

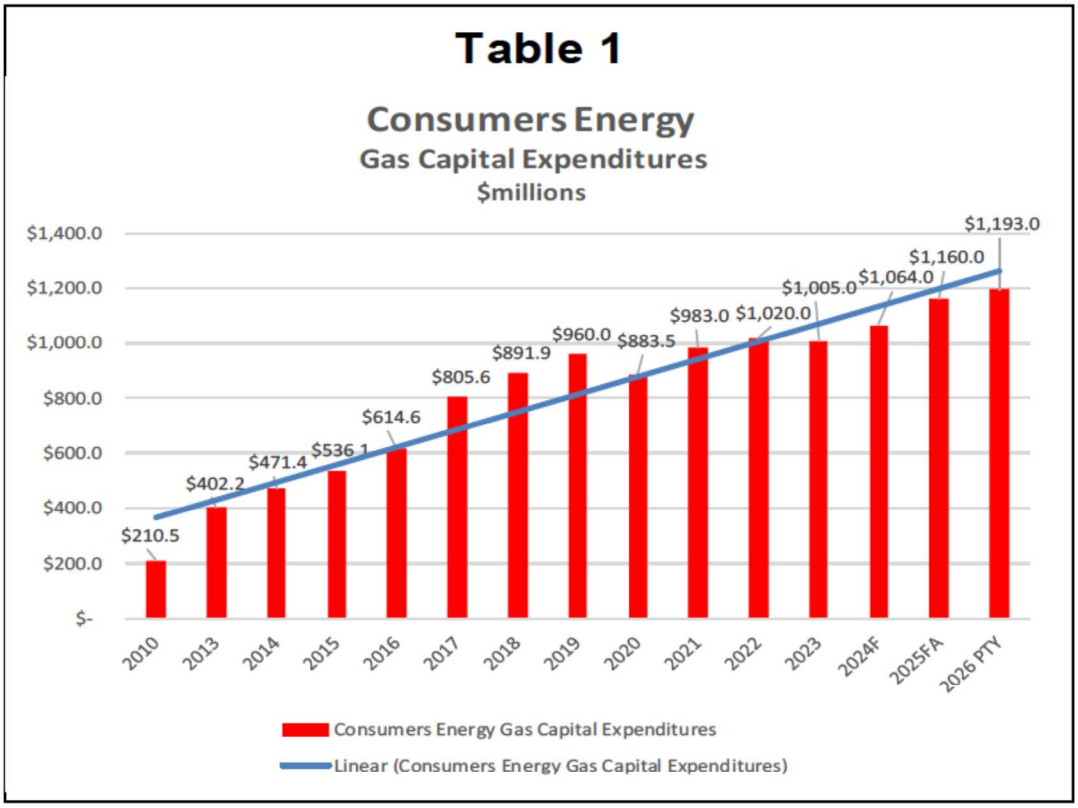
## III. LARGE INCREASE IN RATE BASE AND CAPITAL EXPENDITURES

**Q. PLEASE DISCUSS YOUR CONCERNS WITH THE LEVEL OF CAPITAL EXPENDITURES PROPOSED BY THE COMPANY AND THE RESULTING INCREASE IN RATE BASE.**

A. In this general rate case, CECo has proposed capital expenditures of $1.0 billion for 2023, $1.1 billion for 2024, $967 million for the 10 months ending October 2025 ($1.2 billion annualized), and an additional $1.2 billion for the 12 months ending October 2026. These increases are in addition to capital expenditures of $2.9 billion made during the prior three years from 2020 to 2022.[2] The following chart in Table 1 shows the dramatic increase in capital expenditures over recent years in comparison to more moderate amounts in prior years.

[2] Exhibit A-12, Schedule B-5 in MPSC Case Nos. U-21308, U-21490and U-21806.

**Table 1**




Until 2010, the Company was able to keep capital expenditures around $200 million annually. By 2022, about twelve years later, the level of capital expenditures has increased five-fold to $1.0 billion and continues at this high level into 2023 through 2026.

The capital expenditures have fueled an alarming increase in rate base. As shown below in Table 2, rate base has been growing at double digit rates in recent years, and the Company is proposing to increase rate base again in this rate case by 24% to $11.8 billion over the 2023 historical rate base.

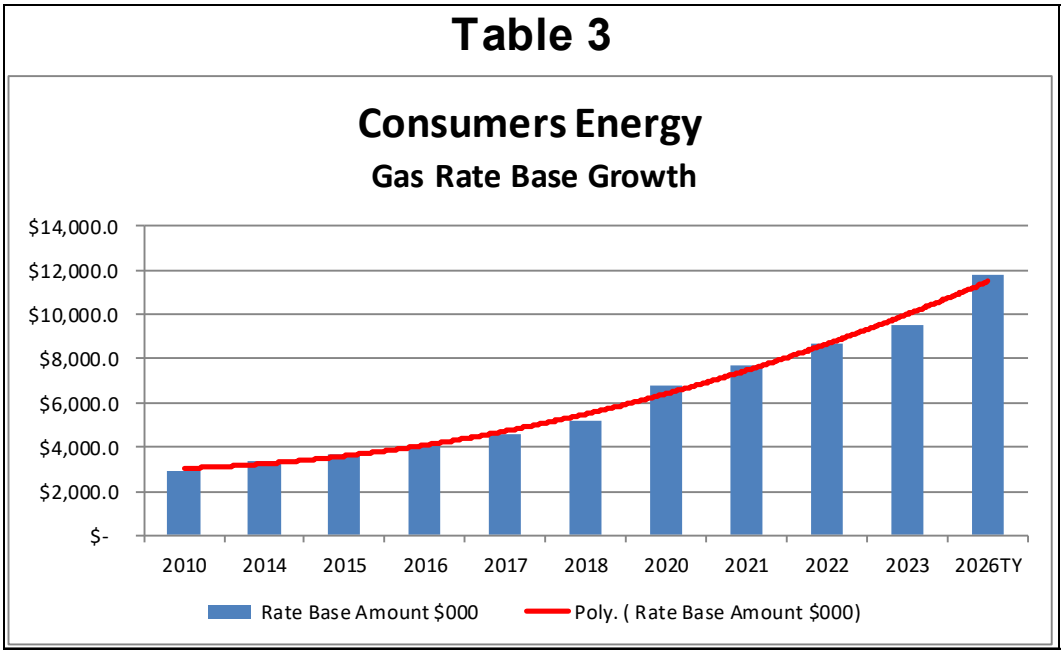
**Table 2**
**Consumers Energy Gas Rate Base Growth**
**2010 to Projected 2026 Test Year**

| Rate Base Year | 2010 | 2014 | 2015 | 2016 | 2017 | 2018 | 2020 | 2021 | 2022 | 2023 | 2026TY |
|---|---|---|---|---|---|---|---|---|---|---|---|
| Docket No. | U-16855 | U-17882 | U-18124 | U-18424 | U-20322 | U-20650 | U-21148 | U-21308 | U-21490 | U-21806 | U-21806 |
| Rate Base [1] (Million) | $ 2,943.8 | $ 3,399.3 | $ 3,654.3 | $ 4,020.0 | $ 4,597.6 | $ 5,200.3 | $ 6,807.9 | $ 7,670.9 | $ 8,658.8 | $ 9,479.0 | $ 11,751.0 |
| Year over Year Change | | 15% | 8% | 10% | 14% | 13% | 31% | 13% | 13% | 9% | 24% |
| Cumulative Change over 2010 Rate Base | | 15% | 24% | 37% | 56% | 77% | 131% | 161% | 194% | 222% | 299% |

[1] Historical actual rate base in each docket, except Case No. U-21608 Test Year proposed amount.

The significant increase in rate base is illustrated by the following chart included in Table 3, which shows the exponential trend of increases in recent years.[3] The current trend has significant negative implications on customer bills as discussed later in my testimony.

**Table 3**




[3] Table 3 shows a Polynomial trend line (Poly.) to show the latest trend in rate base growth.



VERITEXT LEGAL SOLUTIONS

**Q. WHAT DO YOU BELIEVE IS DRIVING THIS DRAMATIC INCREASE IN CAPITAL EXPENDITURES AND RATE BASE SINCE 2010?**

A. I believe there are two main drivers. First, replacement of aging infrastructure and new capital spending to address market growth have required an increase in capital expenditures, which may have accelerated investment to some degree. The Company continues to propose ever-increasing capital expenditures to replace cast iron mains, steel mains and related service lines with few limits. It is unclear what significant changes in the conditions of the pipes and related infrastructure have occurred since 2010 to justify the dramatic escalation in capital expenditures. In fact, the Company has provided no in-depth engineering studies and very limited evidence that there has been a major change in the integrity of its distribution system in the past decade.

The Company also has experienced moderate customer growth in its market area. However, moderate customer growth existed in prior years. Prior to 2010, CECo was able to manage replacement of aging infrastructure and invest in new facilities to meet market growth with more reasonable increases in rate base. Therefore, customer growth and replacement of aging infrastructure by themselves do not fully explain the significant increase in capital expenditures and rate base since 2010.

Second and perhaps a bigger driver is that the replacement of aging gas transmission, storage and distribution infrastructure has given the Company an opportunity to accelerate rate base growth to increase earnings growth. For utility companies, earnings growth is directly related to rate base growth. As shown in the tables above, large increases in capital

expenditures result in double digit increases in rate base which in turn fuels earnings growth, dividend growth, and stock price appreciation for shareholders.

The Company's executive management team, which is largely the same for Consumers Energy and for CMS Energy, has been quite clear and aggressive in communicating to investors and securities analysts its goal of increasing earnings per share at an average annual rate of 6% to 8%. For a utility such as CECo with limited gas sales and revenue growth, the increase in earnings per share comes almost entirely from the increase in capital expenditures and rate base. Exhibit AG-1 includes pertinent sections of a CMS Energy's presentation to investors and securities analysts in March 2025 where Company management communicated its earnings per share, capital expenditures growth goals and achievements. Other recent presentations tell the same story. The presentations point to only gas sales or revenue growth of 1-3%, which does not get anywhere close to propel earnings per share growth of 6% to 8% without higher rate base growth.

Even more troubling is management's recent pronouncement forecasting $20 billion in capital spending over the next 5 years with a large portion of that amount coming from the gas utility. Management has also communicated that capital spending opportunities exist in excess of $50 billion in the coming years. Exhibit AG-1 shows this forecast along with other supporting information.

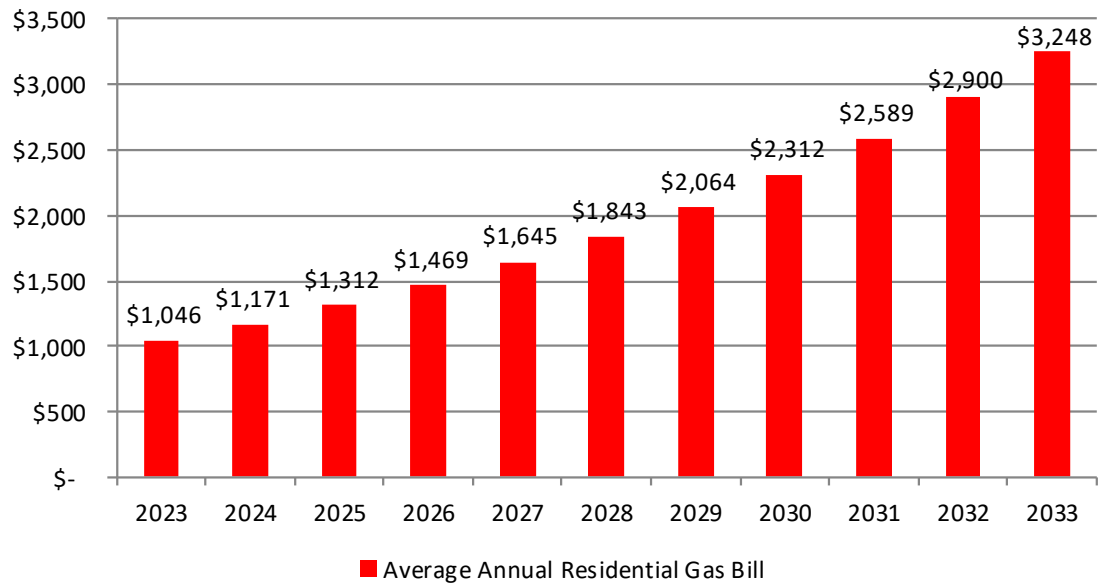
**Q. HAVE YOU DETERMINED WHAT THE IMPACT ON RESIDENTIAL CUSTOMER BILLS COULD BE OVER THE COMING YEARS IF THE**

**COMMISSION APPROVES THE PROPOSED RATE INCREASE AND THAT RATE OF INCREASE CONTINUES INTO FUTURE YEARS?**

A. Yes. Based on the 2023 sales revenue filed by the Company in this rate case, the average annual gas bill for residential customers was $1,046.[4] As shown in Table 2 above, the Company's rate base has been growing in double digits and for the past 10 years from 2015 through the end of the 2026 projected test year at an average annual rate of 12%. If we assume that the Company will continue the current pace of capital expenditures and annual rate base growth of 12% annually, this growth rate accompanied by increases in operating expenses will more than double the actual 2023 annual gas bill of $1,046 in 10 years to $3,248 by 2033. Table 4 below shows the potential increase in the average residential gas bill if the current trend in rate base growth continues, and the price of natural supply remains the same as in 2023. Although gas prices have abated since 2022, with increased demand for natural gas and limited gas supply, they could reach or surpass those prices in future years.

[4] Exhibit A-16, Schedule F2, shows residential revenue of $1,631,131,000 for 2023. The Company had 1,559,943 residential customers for the year (Exh. A-5, Schedule E-2}, which calculates to the actual average residential gas bill of $1,046 for the year.

# Table 4




This potential escalation in annual customer bills is likely to pose a significant burden on residential customers and businesses. In addition, this potential increase in residential gas bills does not take into consideration further escalations in capital expenditures, which the Company seems to be contemplating as discussed above.

The compounding effect of large additions to rate base will continue to increase customer rates to unaffordable levels for many customers, particularly those in fixed and lower income brackets. This trend is not sustainable for customers. To avoid likely bill affordability problems in the future, the Company needs to moderate its capital spending in the coming years.

## IV. Review of Capital Expenditures

**Q. IN YOUR ANALYSIS, HAVE YOU DETERMINED SPECIFIC AREAS WHERE CAPITAL EXPENDITURES COULD BE REDUCED?**

A. Yes. I have analyzed the Company's forecasted capital expenditures by major department or area, and I have identified reasonable expenditure levels that the Commission should adopt. In projecting adjusted capital expenditures for 2025 and the projected test year where applicable I applied an inflation factor to the historical cost base to reflect inflationary cost pressure that the Company may face in those years. The inflation factors are 2.4% for 2025 and 2.5% for 2026. These rates reflect the increase in the forecasted Consumer Price Index during the 2025-2026 periods as shown in the S&P Global Market Intelligence Forecast provided by the Company.[5]

## A. Distribution Plant

In Exhibit A-12 (LDW-1), Schedule B-5.8, the Company forecasted capital expenditures for various Distribution Plant capital programs of $204.6 million for 2024, $227.2 million for the 10 months ending October 2025, and $321.1 million for the 12 months ending October 2026. In comparison, the Company spent $212.9 million in 2023. In my testimony below, I will discuss certain programs where adjustments to the proposed capital expenditures should be made.

[5] Exhibit AG-3 includes WP-HLR-33 with the S&P Global Market Intelligence forecast report.

**1. Mains, Services and Meter Stands**

As shown in Exhibit A-101 (LDW-2), within the Distribution New Business Program, the Company forecasted capital expenditures for the Mains, Services and Meter Stands subprogram of $55.3 million for 2024, $49.6 million for the 10 months ending October 2025, and $61.7 million for the 12 months ending October 2026. Company witness Lincoln Warriner discusses this subprogram beginning on page of 12 of his direct testimony. The Company also refers to this subprogram as new service connections.

On page 13 of his direct testimony, Mr. Warriner states that the Company forecasted 6,800 new service connections for both 2024 and 2025, and 7,000 new connections for 2026. For the 12 months ending October 2026, Mr. Warriner forecasted 6,964 new services to support his forecasted capital expenditures of $61,682,000. On page 14 of his testimony, Mr. Warriner outlines the number of new service connections installed in prior years with the most recent year of 2023 reported at 6,870 new connections.

**Q. DO YOU AGREE WITH THE COMPANY'S FORECASTED CAPITAL EXPENDITURES FOR THE 2025 BRIDGE PERIOD ENDING OCTOBER 2025 AND THE PROJECTED TEST YEAR?**

A. No. In discovery, the Attorney General asked the Company to provide the actual number of new service connections installed in 2024 along with other pertinent data about new housing starts in Michigan that would inform a more accurate forecast of new service connections for 2025 and 2026. In response, the Company reported that the actual number

of new service connections for 2024 was 5,950 or nearly 13% lower than the Company's forecast of 6,800 units.[6] The Company also provided the forecast of new Michigan housing starts compiled by S&P Global Market Intelligence as of February 2025. The report forecasts an increase in Michigan housing starts of 6.3% for 2025 and a decline of 7.9% in 2026.[7] Housing starts and new service connections are sensitive to mortgage interest rates. The general expectation by economists and home buyers has been that mortgage interest rates would decline further in 2025 and in subsequent years. However, persistently high inflation rates and other economic factors have prevented the Federal Reserve Bank from lowering interest rates further with no clear expectation currently of further declines in 2025. Therefore, the Company's forecast that new service connections would rebound to 6,800 units in 2025 and 7,000 units in 2026 from the actual 5,950 units completed in 2024 is no longer realistic.

**Q. WHAT IS YOUR FORECAST FOR NEW SERVICE CONNECTIONS FOR 2025 AND 2026 AND THE RELATED CAPITAL EXPENDITURES?**

A. Although the S&P Global forecast of Michigan housing starts shows an increase of 6.3% in 2025 followed by a decline of 7.9% in 2026, over the two-year period there is a net decline of approximately 2% over the level of housing starts in 2024. Instead of forecasting a decline over this timeframe, I have taken a conservative approach and

[6] Exhibit AG-2 includes DR AG-CE-0340.
[7] Id. includes DR AG-CE-0341 Partial.

forecasted that new service connections for 2025 and 2026 will be similar to the 5,950 units reported for 2024.

Based on this revised forecast, I calculated that capital expenditures for 2025 would be $52,658,000 using the Company's forecasted unit cost of $8,850.[8] The amount pertaining to the 10-month bridge period ending October 2025 is $43,882,000 ($52,658,000 x 10/12). This amount is $5,714,000 lower than the Company's forecast of $49,596,000.

For 2026, the forecasted capital expenditures are $53,865,000 (5,950 units x $9,053). For the 12 months ending October 2026, the forecasted capital expenditures are $53,664,000.[9] This amount is $8,018,000 lower than the $61,682,000 forecasted by the Company.

**Q. ON PAGE 15 OF HIS DIRECT TESTIMONY, MR. WARRINER DISCUSSES FORECASTS OF HOUSING PERMITS AND U.S. HOUSING STARTS TO SUPPORT HIS FORECAST FOR NEW SERVICE CONNECTIONS FOR 2025 AND 2026. WHAT ARE YOUR OBSERVATIONS?**

A. As I have stated in my testimony in previous rate cases on this subject, forecasts of housing permits are not as a reliable predictor of new service connections as housing starts. The forecast of housing permits anticipates a level of new housing construction that is usually issued months ahead of the start of construction while housing starts reflect the near term

[8] Unit cost from Table 5 on page 19 of Mr. Warriner's direct testimony, (5,950 units x $8,850 = $52,658,000).
[9] ($53,865,000 x 10/12) + ($52,658,000 x 2/12) = 53,664,000.

start of construction. Therefore, housing starts are a better predictor of the level and timing of new service line installation activity for the forecasted periods.

Regarding the Company's use of forecasted U.S. housing starts, this forecast is too far removed from what is likely to occur in Michigan given the significant migration of population to southern and southwestern states and the large increases in new housing in those areas of the country. The forecast of Michigan housing starts I used is more pertinent to the level of housing activity and new service connections that the Company will face in its Michigan service area.

**Q. ARE YOU PROPOSING ANY ADJUSTMENTS TO THE COMPANY'S FORECASTED CAPITAL EXPENDITURES FOR 2024 FOR NEW SERVICE CONNECTIONS?**

A. Yes. As stated above, the Company forecasted a higher number of new service connections for 2024 than it actually installed and included higher capital expenditures in this rate case than it actually incurred. The Company forecasted that it would incur capital expenditures of $55,338,000 for 2024 when it actually incurred only $52,271,000 for the year.[10] The difference of $3,067,000 should be removed from the Company's forecasted capital expenditures in this rate case. Customers should not pay for costs the Company did not incur, including the return on investment, depreciation expense, and property taxes that the Company would recover if those costs were not removed from rate base. In prior

[10] DR SA-CE-399 for 2024 actual. Exhibit A-101, page 1, line 1 for the forecasted amount.

rate cases, the Commission has ruled that forecasted costs for the bridge period not incurred by the Company should not be included in rate base and in the calculation of new rates. Therefore, I recommend that $3,067,000 of capital expenditures be removed from the Company's forecasted 2024 capital expenditures.

**Q. WHAT IS YOUR OVERALL RECOMMENDATION FOR ADJUSTMENTS TO THE COMPANY'S FORECASTED CAPITAL EXPENDITURES FOR NEW SERVICE CONNECTIONS?**

A. As discussed above, I recommend that the Commission remove $3,067,000 for 2024, $5,714,000 for the 10 months ending October 2025, and $8,018,000 for the projected test year from the Company's forecasted capital expenditures.

**2. Large New Business Projects**

As shown in Exhibit A-101 (LDW-2), the Company forecasted capital expenditures for the Large New Business Projects subprogram of ~~$8.7~~$9.7 million for 2024, $3.1 million for the 10 months ending October 2025, and nearly $5.0 million for the 12 months ending October 2026. Company witness Lincoln Warriner discusses this subprogram beginning on page of 22 of his direct testimony.

In response to discovery, the Company provided a list of seven projects that it expected to complete between 2024 and the end of the projected test year. In addition, the Company identified $4,778,000 of capital expenditures for unspecified large projects that could arise

during the projected test year but that are undetermined and not yet known.[11] These projects are currently unknown, and the Company has included an amount as simply a placeholder for projects that may or may not occur in the future. The Commission has ruled in prior rate cases that placeholder amounts should not be included in rate base given that they do not pertain to known projects and the large uncertainty of whether those capital expenditures will be incurred by the Company. Therefore, my recommendation is that the $4,778,000 should be removed from the capital expenditures forecasted by the Company for the projected test year.

Regarding the seven identified projects, the Company reported that for two of the projects no contracts have yet been signed with the customers. The first project is with the Lansing BW&L for the Delta Energy Park and the contract is still in progress. The second project is for an industrial site development and no contract has been initiated. The two projects represent capital expenditures of $2,054,000 for the 10 months ending October 2025 and $124,000 for the projected test year. Given that the contracts have not yet been finalized, the capital expenditures for the two projects are still very preliminary and uncertain.

Given the uncertainty with the two projects, it is premature to include those capital expenditures in rate base in this rate case. If the project costs are not removed the Company would recover the return on investment, depreciation expense, and property taxes it has not actually incurred. If the Company actually incurs the capital spending, it can include those amounts in the next rate case when they are known. Therefore, I recommend that

[11] Exhibit AG-2 includes DR AG-CE-0346 with ATT_1.

the capital expenditures of $2,054,000 for the 10 months bridge period and the $124,000 for the projected test year be removed for the Company forecasted capital expenditures.

**Q. ARE YOU PROPOSING ANY ADJUSTMENTS TO THE COMPANY'S FORECASTED CAPITAL EXPENDITURES FOR LARGE NEW BUSINESS PROJECTS FOR 2024?**

A. Yes. As shown in the attachment to DR AG-CE-0346 (Exhibit AG-2), the Company forecasted that it would incur capital expenditures of $9,709,000 for 2024 when it actually incurred only $7,761,000 for the year. The difference of $1,948,000 should be removed from the Company's forecasted capital expenditures in this rate case. Customers should not pay for costs the Company did not incur, including the return on investment, depreciation expense, and property taxes that the Company would otherwise recover if those costs are not removed from rate base.

**Q. WHAT IS YOUR OVERALL RECOMMENDATION FOR ADJUSTMENTS TO THE COMPANY'S FORECASTED CAPITAL EXPENDITURES FOR LARGE NEW BUSINESS PROJECTS?**

A. I recommend that the Commission remove $1,948,000 for 2024, $2,054,000 for the 10 months ending October 2025, and $124,000 for the projected test year from the Company's forecasted capital expenditures.

**3. Asset Relocation**

I am addressing two subprograms under Asset Relocation. As shown in Exhibit A-102 (LDW-2), the Company forecasted capital expenditures for the Asset Relocation-Civic Improvement subprogram of $64.1 million for 2024, $63.6 million for the 10 months ending October 2025, and $82.2 million for the 12 months ending October 2026. For the Asset Relocation-Reimbursable subprogram, the Company forecasted capital expenditures of $22.7 million for 2024, $12.2 million for the 10 months ending October 2025, and $16.6 million for the 12 months ending October 2026. Company witness Lincoln Warriner discusses these subprograms beginning on page of 25 of his direct testimony.

Regarding Civic Improvements, in discovery, the Attorney General and the Commission Staff (Staff) asked the Company to expand the information provided in Mr. Warren's direct testimony and provide the number of projects and related forecasted capital expenditures for each year 2024 to 2026 along with the basis for developing those forecasts. The Attorney General also requested that the Company provide the actual number of projects and related spending for 2024. In response, the Company provided the actual number of projects for 2019 to 2023 and the forecasted numbers for 2014 to 2026 with related capital expenditures. However, the Company could not provide the actual number of projects and capital spending for 2024 before preparation of this testimony, claiming that the accumulation of this information was still in progress.

In response to Staff Audit Request SA-CE-402, the Company also explained that the Company forecasted costs were based on prior years' historical experience with a 3% annual growth rate.

**Q. WHAT IS YOUR ASSESSMENT OF THE COMPANY'S FORECASTED CAPITAL EXPENDITURES FOR ASSET RELOCATION-CIVIC IMPROVEMENT?**

A. Based on the analysis below, I found the Company's forecasted capital expenditures for Civic Improvements to be significantly overstated. The forecasted capital spending should reflect the level of work activity that the Company plans to undertake during the respective periods. For this program, the level of activity is reflected in the number of planned projects, the number of feet of distribution main replaced/installed, and the number of services to be relocated. The attachment to SA-CE-402 shows that on average for the three years 2022-2024 the Company completed or planned to complete 154 projects and install or planned to install 201,945 feet of main and 1,787 service lines. In this calculation, I used the Company's forecasted 2024 numbers instead of actual number due to the Company's inability to provide timely actual data.

In comparison, for 2025 the Company plans to complete 22 more projects than the 3-year average but install only 145,330 feet of main and 1,689 services. The fewer feet of main and services planned for 2025 represent a reduction of 28% and 5%, respectively from the levels installed on average in the prior three years. Similarly, for 2026, the Company plans to do more projects but still install fewer feet of main and services than the 2022-2024 three-year average. The reduction is 18% for mains and 3% for services. However, the

Company's forecasted capital spending does not track with the level of work activity planned.

**Q. DID YOU CALCULATE AN APPROPRIATE LEVEL OF CAPITAL SPENDING FOR 2025 AND 2026 THAT REFLECTS THE LEVEL OF WORK ACTIVITY?**

A. Yes. The largest driver of capital spending for relocation projects is the number of feet of main to be relocated and replaced with the number of services to be replaced adding to that cost. Although the Company did not provide the cost split between relocating mains and services, I calculated the cost of relocating and replacing services at $11,267,000 for 2025 and $12,857,000 for 2026.[12] These amounts are based on the cost per vintage service line replaced by the Company under the Vintage Service Replacement program.[13] Thus, the cost to relocate and replace services accounts for approximately 16% of the total capital expenditures forecasted by the Company for Civic Improvements for 2025 and 2026.[14]

As I stated earlier, for 2025 the feet of main to be installed is 28% lower than in the prior three-year average and the number of services is 5% lower. By weighting these percentages by the corresponding capital spending in each cost category, I calculated an overall percentage reduction of 24%.[15] For the three-years 2022-2024, the Company incurred average capital spending for Civic Improvements of $83,580,000.[16] After

[12] 2025: 1,689 units x $6,671 unit cost = $11,267,000. 2026: 1,740 units x $7,389 unit cost = $12,857,000.
[13] Company response to DR AG-CE-0793 Attachment 1.
[14] $11,267,000 ÷ $70,770,000 = 16%. $12,857,000 ÷ $83,444,000 = 15%.
[15] (-28% x 84%) + (-5% x 16%) = -24.3%.
[16] From Tables 9 and 10 of Mr. Warriner's direct testimony at pages 30 and 31. (2022: $103,075,000 + 2023: $83,518,000 – 2024: $64,148,000) ÷ 3 = $83,580,000

adjusting for inflation at 2.4%, the base cost for 2025 is $85,586,000. Applying the 24% reduction in work activity, decreases the adjusted forecasted capital expenditures for 2025 to $65,045,000.[17] The applicable amount for the 10 months ending October 2025 is $54,204,000 ($65,045,000 x 10/12). This amount is $9,408,000 lower than the $63,612,000 forecasted by the Company.

For 2026, the same approach results in a reduction in overall work activity of 16% from the 2022-2024 three-year period.[18] After applying this percentage reduction to the inflation adjusted three-year average capital expenditures of $87,726,000, the forecasted capital expenditures for 2026 are $73,690,000.[19] The amount applicable to the projected test year is $72,249,000.[20] This amount is $9,913,000 lower than the Company's forecasted amount of $82,162,000.

**Q. DID YOU PERFORM A SIMILAR ASSESSMENT OF THE COMPANY'S FORECASTED CAPITAL EXPENDITURES FOR ASSET RELOCATION-REIMBURSABLE PROJECTS?**

A. Yes, but on a more limited extent due to the inability of the Company to provide forecasted workload activity for 2025 and 2026. In discovery, the Attorney General asked the Company to provide both historical and forecasted work units for 2019 through 2026, as well as work performed for large customer requested relocation projects. In response, the

[17] $85,586,000 x 76% = $65,045,000.
[18] (-18% x 84%) + (-3% x 16%) = -15.6%.
[19] $83,580,000 x 1.024 x 1.025 = $87,726,000 x 84% = $73,690,000.
[20] $73,690,000 x 10/12 + $65,045,000 x 2/12 = $72,249,000.

Company provided the historical information through 2024 but stated that it had not developed forecasted work units for 2025 and 2026. In response to additional discovery, the Company also stated that in developing the forecasted capital expenditures for 2024, 2025 and 2026, it had applied a 3.5% annual cost escalation rate on the 2023 cost levels and subsequent year to cover for both inflation and workload growth.[21] This statement is unsupported because no forecasted inflation rates or work activities were disclosed in the discovery response.

To arrive at a reasonable capital expenditures forecast for 2025 and 2026, I started with the most recent three years of actual capital expenditures for 2022-2024 and reduced those amounts for the expenditures pertaining to large customer relocations to determine a normalized level The net result is an historical average spending level of $14,089,000.[22] Adjusted for inflation at 2.4%, the forecasting capital expenditures are $14,427,000 for 2025 and $12,023,000 for the 10 months ending October 2025. This amount is $203,000 lower than the $12,226,000 forecasted by the Company.

For 2026, I adjusted the three-year historical further for another year of inflation for a total amount of $14,788,000.[23] The amount pertaining to the projected test year is $14,728,000. This amount is $1,919,000 lower than the Company's forecast of $16,647,000.

[21] Exhibit AG-4 includes DR AG-CE-0352, 0353, and 0762 with attachments.
[22] Attachment to AG-CE-0352 (Exhibit AG-4) total line for 2022, 2023, and 2024, less the amounts for large customer requested relocations, and divided by 3 = $14,089,000.
[23] $14,089,000 x 1.024 x 1.025 = $14,788,000.

**Q. WHAT IS YOUR OVERALL RECOMMENDATION FOR ADJUSTMENTS TO THE COMPANY'S FORECASTED CAPITAL EXPENDITURES FOR ASSET RELOCATION?**

A. I recommend that the Commission remove $9,611,000 for the 10 months ending October 2025, and $11,832,000 for the projected test year from the Company's forecasted capital expenditures.

**4. Regulatory Compliance Program**

As shown in Exhibit A-103 (LDW-4), the Company forecasted capital expenditures for the Regulatory Compliance Program of $45.2 million for 2024, $91.7 million for the 10 months ending October 2025, and $150.3 million for the 12 months ending October 2026. Included in those amounts are capital expenditures for MAOP projects for large distribution pipelines and related facilities.[24] For 2023, the Company incurred capital spending of $1,607,000 in this area. For future years, the Company forecasted capital expenditures of $9,295,000 for 2024, $59,964,000 for the 10 months ending October 2025, and $115,812,000 for the projected test year. Mr. Warriner discusses the Distribution MAOP program and related regulations beginning on page 46 of his direct testimony.

Although the MAOP projects fall within recently issued regulations issued by the Pipeline Hazardous Materials Safety Administration (PHMSA), the genesis of the problem requiring the replacement or remediation of pipelines to re-establish the MAOP is the lack

[24] MAOP = Maximum Allowable Operating Pressure for a pipeline or related facilities.

of traceable, verifiable, and complete (TVC) records that should have been maintained by the Company. In response to discovery, the Company acknowledged the missing records that prevent it from confirming the appropriate MAOP at which the pipeline should be currently operating.[25] Although the PHMSA rules provide for procedures and alternative steps that the Company can undertake short of replacing the pipeline to develop TVC records and to re-establish the MAOP,[26] the Company claims that it needs to replace 15 distribution pipeline segments, as identified in Table 17 on page 48 of Mr. Warriner's direct testimony.

In discovery, the Attorney General asked the Company to provide a list of MAOP projects where it was able to avoid replacement of the pipeline or pipeline segment and reducing capital expenditures by undertaking the other options to replacement outlined in the PHMSA rule. In response, the Company stated that so far it has not identified any other alternatives to replacement.[27] The attachment to the response also shows that for the 15 projects contemplated for 2024 through 2026, the Company has chosen only the replacement option at a total cost of $206.3 million over the three-year period.

**Q. WHAT IS YOUR ASSESSMENT OF THE CAPITAL EXPENDITURES THAT THE COMPANY SEEKS TO INCLUDE IN RATE BASE FOR MAOP PROJECTS?**

[25] Exhibit AG-5 includes DR AG-CE-0358 with ATT_2.
[26] Exhibit AG-6 includes a copy of PHMSA rules.
[27] Exhibit AG-5 includes DR AG-CE-0357with ATT_1.

A. The reason for replacement of the pipelines under the MAOP projects is the direct result of the Company not having the appropriate records to verify that the pipelines can operate at the designed pressure level and not knowing their material properties and attributes that would assist in that verification. These are basic records that the Company should have in its possession from when the pipeline was installed. The PHMSA rules simply require that the Company check its records to verify it is operating the pipelines and related facilities at the MAOP specific to those facilities. The need to replace the pipelines emanates from the fact that the Company did not maintain the necessary records to perform the required verification.

Customers should not pay for the cost to replace pipelines due to the Company's failure to maintain appropriate records irrespective of when the pipeline was initially installed. The Company has the sole responsibility to maintain those records and periodically confirm that it is operating its pipelines at the appropriate allowable pressure. The PHMSA rules enacted in 2019 simply require that pipeline operators do now what they should have been doing all along. Therefore, the cost of replacing the pipeline segments under the MAOP projects should be borne entirely by the utility and not its customers. However, as a reasonable accommodation, given the age of the pipelines being replaced, the Commission could allow the Company to recover 50% of the cost of replacement and split the burden 50/50 between the Company and customers.

**Q. IN HIS TESTIMONY AND RESPONSES TO DISCOVERY, MR. WARRINER STATES THAT LINE 1080 IS NOT BEING REPLACED BUT IS BEING**

**SUPPLEMENTED BY A SECOND LINE. DOES THAT PLAN CHANGE YOUR ASSESSMENT?**

A. No. The reason why the Company needs to supplement Line 1080 with a second line is because Line 1080 can only operate at a limited pressure level due to the inability to pressure test the line given the lack of records to allow it to establish the pipeline design MAOP. By operating the line at a lower pressure based on available records, the Company cannot adequately meet customers' gas demand and now wants to install a second parallel line of 6.7 miles at a cost of $35 million. Therefore, this project would not exist but for the Company's lack of traceable, verifiable, and complete records for Line 1080.

**Q. DID YOU DETERMINE THE AMOUNT OF CAPITAL EXPENDITURES THAT THE COMMISSION SHOULD REMOVE FROM THIS RATE CASE PERTAINING TO THE DISTRIBUTION MAOP PROJECTS?**

A. Yes. In response to DR AG-CE-0358 (Exhibit AG-5), the Company provided an expanded Table 17 from Mr. Warriner's direct testimony that shows each MAOP project with the related capital expenditures by year and for the bridge period and the projected test year. That information has been summarized in the table below and the Company's proposed capital spending corresponds to the forecasted capital expenditures on line 3 of page 1 of Exhibit A-103 (LDW-4).

| MAOP Capital Expenditures (000): | Company Proposed Amount | 50% Disallowance | Amount Recoverable |
|---|---|---|---|
| 2023 Actual | $ 1,607 | $ 804 | $ 803 |
| 2024 Forecast | $ 9,295 | $ 4,648 | $ 4,647 |
| 10 Months Ending October 2025 | $ 59,964 | $ 29,982 | $ 29,982 |
| Projected Test Year | $ 115,811 | $ 57,906 | $ 57,905 |

Based on the discussion above, I recommend that the Commission disallow recovery of 50% of the capital expenditures, as calculated in the summary table. This involves disallowance of $804,000 for 2023, $4,648,000 for 2024, $29,982,000 for the 10 months ending October 2025, and $57,906,000 for the project test year.

Later in my testimony, I will address the recovery of O&M expense pertaining to the review of pipeline MAOP records.

**Q. HAS THE COMMISSION PREVIOUSLY RULED ON THE RECOVERY OF COSTS PERTAINING MAOP PROJECTS?**

A. Yes. In Case No. U-21291, which was the DTE Gas Company 2024 rate case, the Commission approved the Attorney General recommendation to disallow 50% of the O&M expense pertaining the review costs of MAOP records included in the projected test year. In reaching its decision, the Commission stated:

> The Commission respectfully disagrees with the ALJ's recommendation regarding the MAOP Records Review. The Commission previously addressed DTE Gas's MAOP Records Review in Case No. U-20940 and determined that the 2019 revisions to federal pipeline safety regulations and the "2011 advisory bulletin are not new record keeping requirements and that DTE Gas was required previously by the MGSS to perform strength tests, including MAOP tests, and to maintain those records for the life of the pipeline." December 9 order, p. 33. As a result, the Commission instructed

> that, in future rate cases, "DTE Gas must adequately justify that the required [MAOP] work is a direct result of the new requirements in the regulations and not a result of the company's historically poor record keeping practices." Id., pp. 123-124.
>
> The Commission acknowledges that DTE Gas provided testimony in this case asserting the need to implement a reconfirmation plan in conformance with the PHMSA revised regulations. See, 4 Tr 620. However, the Commission finds that reconfirmation of MAOP under the pertinent regulations are only required if the records necessary to establish MAOP are not TVC. See, 49 CFR 192.624(a)(1). Therefore, the Commission is not persuaded that DTE Gas's projected remediation work is not a result of the company's historically poor recordkeeping practices. The Commission, thus, finds that cost sharing is appropriate for the projected O&M expense for the MAOP Records Review. Accordingly, the Commission declines to adopt the ALJ's recommendation, and instead adopts the Attorney General's proposal to remove $875,000 from DTE Gas's O&M expense for the projected test year.[28]

In Case No. U-20940, which was the DTE Gas 2021 rate case, the Commission declined to adopt the Attorney General's recommendation to disallow 50% of the capital expenditures for the Middlebelt deration project that related to MAOP remediation and pipeline replacement. In its order the Commission stated:

> The Commission finds that recovery of the capital costs related to the Middlebelt deration project should be permitted. The Commission agrees with the ALJ's findings that the 2019 PHMSA rules and 2011 advisory bulletin are not new record keeping requirements and that DTE Gas was required previously by the MGSS to perform strength tests, including MAOP tests, and to maintain those records for the life of the pipeline. However, the Commission is disinclined to disallow the capital costs associated with this project as they are necessary to reestablish the MAOP of the pipeline and to ensure safe operation. Safety is a core mission of the Commission's regulation of natural gas operations within the state, and safety has been emphasized by the Commission on numerous occasions. Namely, in DTE Gas's previous rate case, Case No. U-18999, the company sought recovery of the O&M expenses associated with record remediation in response to the 2019 PHMSA rules, which were pending at the time. While the company did not request recovery of capital expenses and the Commission disallowed the O&M expense because the federal rules were not yet finalized, the Commission spoke to the importance of safety…. Considering the company's testimony that the Middlebelt deration project was ranked the highest distribution risk and among the highest risks for transmission, the Commission finds that the safety concern justifies cost recovery of the capital expense in this instance.

[28] Case No. U-21291, MPSC Order dated November 7, 2024 at page 148.



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Although I appreciate the Commission concern and the need to take remediation actions when safety issues are involved, the issue here is not whether the work should be done or not done to remedy problems but who should pay for it. In both rate cases, the Commission has clearly concluded that the responsibility to maintain appropriate records falls on the utility. The Commission also concluded that reconfirmation of MAOP under the pertinent regulations are only required if the records necessary to establish MAOP are not TVC.

The Commission determined that the utility's projected remediation work was the result of the company's historically poor recordkeeping practices and that cost sharing for the projected O&M expense for the MAOP Records Review was appropriate. By logical extension, the capital expenditures to replace or remediate various pipeline segments and related facilities should also be accorded the same cost sharing treatment between the Company and customers. The only difference is that one is an operating expense and the other is a capital expenditure. However, the cost sharing treatment should be the same.

Therefore, I recommend that the Commission adopt my recommendation to allow the Company to recover only 50% of the proposed capital expenditures for MAOP remediation or replacement and disallow the remaining expenditures, as I have outlined above.

**Q. IS THERE ANOTHER REASON TO ALLOW THE COMPANY TO ONLY RECOVER 50% OF THE PROPOSED CAPITAL SPENDING FOR MAOP PIPELINE PREPLACEMENT PROJECTS?**

A. Yes. As discussed above and shown in the attachment to DR AG-CE-0357 (Exhibit AG-5), the Company concluded that replacement of the pipeline segments is the only preferred solution to reaffirm the MAOP and has rejected other options permitted under the PHMSA rule. It is not clear how thorough the review process was to reach that conclusion. The statements provided in the discovery response point to vague conclusions about operational risk reduction and likelihood of success. The disallowance of 50% of the project cost would give the Company the incentive to minimize capital expenditures if it must absorb half the cost of the project. This extra incentive could spur the use of other options and reduce overall capital expenditures.

**5. Material Condition Program – EIRP Capital Expenditures**

As shown on page 1 of Exhibit A-82 (KAP-4), the Company forecasted capital expenditures for the Enhanced Infrastructure Replacement Program (EIRP) of $195.6 million for 2024, $207.3 million for the 10 months ending October 2025, and $251.4 million for the 12 months ending October 2026. In comparison, the Company spent $181.9 million in 2023. Company witness Kristine Pascarello discusses the EIRP beginning on 35 of her direct testimony.

**Q. PLEASE PROVIDE A BRIEF SUMMARY OF THE EIRP.**

A. In Case No. U-16855 filed in September 2011, the Company proposed a comprehensive main replacement program that would achieve the following objectives:

1. Replacement of all cast iron mains over the course of the 25-year program.

2. Replacement of all bare, oxyacetylene welded, threaded & coupled and cathodically-unprotected steel mains over the course of the 25-year program.

3. Replacement of 100 miles of transmission gas mains located in high consequence areas (HCA) over the 25-year program.

4. Replacement of approximately 70 miles of ERW piping located in gas storage fields and install launcher/receivers, as necessary, to permit future inspection by in-line inspection (ILI) technology.[29]

According to the direct testimony of Steven Beachum in that rate case, the Company would be able to achieve the 25-year replacement target with an annual capital spending level of $70 million. If that plan had been successful, full replacement of targeted mains would have been achieved by the year 2036, or 11 years from now. However, the Company's plan has not materialized at anything close to what was proposed in 2011.

At the beginning of the main replacement program, the Company had targeted replacement of 2,869 miles of mains, which over the 25-year plan period would have resulted in an annual replacement rate of 115 miles at an average annual capital spending level of $70 million, or $609,000 per mile. During the 13 years from 2012 to 2024, the Company retired approximately 904 miles of the targeted old mains plus other at-risk mains for a total of 1,131 miles of retired mains.[30] The Company replaced those mains by installing 1,100 miles of new mains at a cost of $1.277 billion, or $1,160,000 per mile.[31] The retirement rate per year on the old targeted mains has been 85 miles of main instead of the planned 115 miles per year.

[29] MPSC Case No. U-16855, Steven Beachum direct testimony at page 33.
[30] Exhibit AG-7 includes DR AG-CE-0365 with Attachment.
[31] Id. includes DR AG-CE-0386 with ATT_1 showing the miles installed. The $1.277 billion cost is update from Case U-21490 of $1.084 billion from 2012 through 2023 plus $193 million spent in 2024.



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What is most concerning is the fact that the Company had projected it would cost $609,000 to replace a mile of main when it announced the program in 2011.[32] Instead, the actual average cost over the past 13 years has been $1.2 million per mile, or nearly two times the original estimate. Exhibit AG-7 includes the Company's response to discovery requests AG-CE-0365, 0385, 0386 and 0390 with the information discussed above and additional program details.

In addition to the base distribution system pipe replacement program, the Company also includes in the EIRP the replacement of steel pipe for Transmission lines Operated by the Distribution department. These are referenced or identified as TOD projects. During the 13 years from 2012 to 2024, the Company retired approximately 33.4 miles of TOD mains and replaced them with 58.3 miles of new main.[33]

**Q. IN YOUR REVIEW OF THE LARGER EIRP PROJECTS, DID YOU IDENTIFY CERTAIN COSTS THAT SHOULD BE REMOVED FROM THE COMPANY'S FORECASTED CAPITAL EXPENDITURES?**

A. Yes. After reviewing the list of EIRP projects with a cost of $5 million or greater included on page 3 of Exhibit A-82 (KAP-4), the Attorney General asked the Company to identify the current phase of project development. In response, the Company identified projects that were in different phases of development from Design Not Started to Design in

[32] $70 million per year divided by 115 miles of main targeted for replacement annually over a 25-year period equals to an average cost per mile of $609,000.
[33] Exhibit AG-7 include DR AG-CE-0386 with ATT_1.

Progress, Design at 30%, Design at 90%, Design Completed, Released for Construction, and Under Construction.[34] Eighteen of the 30 projects listed in the $5 million plus category have had no design started yet or the design is at 30% or less completed. The capital expenditures for the 18 projects total to $166 million. A strong case can be made that these projects are still in the early phase of development and the capital expenditures should not be included in rate base in this rate case. Of the 18 projects, seven projects, all of which have been scheduled to be completed in 2026, have not yet had any design work started or only minimal design (less than 30%) completed for a portion of one project. These seven projects represent $84,889,000 of capital expenditures for the projected test year. The projects are identified in the table below.

| Line # Page 3 Exh. A-82 | EIRP Project Description | Projected Test Year Capex |
|---|---|---|
| 17 | SAG4 - Ph 1,2,3 | 17,749 |
| 18 | BCY2 - Ph 2 | 7,344 |
| 19 | ALM2 - Ph 1,7,8 | 9,303 |
| 20 | ALM5 - Ph 2 Line 1070g | 4,713 |
| 23 | ROK10 - Ph 1,2,3,4,5,6 | 15,423 |
| 24 | ROK7 - Ph 4,5,6,7,8 | 23,625 |
| 25 | KAL3 - Ph 8,9,10 | 6,732 |
| | Total | $ 84,889 |

These projects are clearly in the initial phase of development with no design work started, or only a minimal amount in the case of one project, and a high degree of uncertainty about the cost and completion of the projects by the end of the projected test year. Therefore, I

[34] Exhibit AG-8 includes DR AG-CE-0430 with Attachment 1 and AG-CE-0802.

recommend that the $84,889,000 of capital expenditures for this group of seven projects be removed from this rate case. If the Company is able to complete these projects, it can recover the related costs in the next rate case given the annual frequency of rate cases filings.

**Q. DO YOU HAVE OTHER OBSERVATIONS AND RECOMMENDATIONS WITH REGARD TO THE COMPANY'S FORECASTED EIRP CAPITAL EXPENDITURES FOR THE PROJECTED TEST YEAR AND FUTURE YEARS?**

A. Yes. As stated earlier, the Company expects to reach a new peak level of capital spending on the EIRP program in the projected test year at $251.4 million. In contrast, the Company spent $181.9 million in 2023. The projected test year spending level is an increase of 38% in less than 3 years. The Company is also not meeting its commitment to refrain spending. In the settlement agreement for Case No. U-21490, the Company stated that it would keep the EIRP spending level for the 12 months ending September 2025 at $215.3 million.

As shown in Table 7 on page 49 of Ms. Pascarello's direct testimony, the Company now forecasts that spending for 2025 will reach $250 million or a prorated amount of $237 million for the 12 months ending September 2025. This increasing spending trend for the EIRP is not sustainable from a customer affordability viewpoint and must be reversed. The Commission should set a firm spending budget for the EIRP to avoid the program's current runaway cost.

Most homeowners must live within their own cost budgets and do not have unlimited resources to be able to afford ever increasing household costs. They make hard choices every day as to where to spend their money within the available resources. Similarly, the Company needs to set an annual budget to replace and install the number of miles of main that can be completed within a set budget cap. The current practice of unlimited and increasing capital spending on the EIRP program needs to be restrained.

Based on the actual spending of $181.9 million in 2023 and adjusting that amount for forecasted inflation of 3.2% in 2024, 2.4% in 2024, and 2.5% in 2026, I propose a spending budget cap of $197 million for the projected test year ending October 2026. That spending level would be adjusted for the CPI rate of inflation in future years.

Although the lower spending level that I propose may reduce somewhat the number of miles that the Company planned to retire and install in the projected test year and future years, the completion of the program would not be affect significantly. In discovery, the Attorney General asked the Company to provide the end year of the EIRP if the Company pursued a pace of pipe replacement equivalent to the year 2023.

In response, the Company stated that under that assumption, the end date of the EIRP program would be extended from the current expected date of 2035 to the year 2038. The completion date would extend to 2040 if retirement of additional TOD steel pipe and wrapped steel pipe is added to the EIRP.[35] This three-to-five-year extension of the

[35] Exhibit AG-9 includes DR AG-CE-0391 and 0781.

program seem reasonable if it helps moderate the rate of increase in spending to a level equivalent to 2023 adjusted for inflation.

The lower capital spending level will also give the Company added incentive to reduce the cost per mile of main installed and reduce pressure on scarce resources. The Company is competing for limited resources, whether through the direct hire of employees or through subcontractors, and also for materials and equipment, with other utilities around the country, as those utilities also have undertaken large pipe replacement programs. This competition for limited resources has contributed to the higher cost of pipe replacement under the Company EIRP program during recent high inflationary periods. A more moderate pace of pipe replacement will help take the pressure off the competition for those resources.

It should also be pointed out that through the risk-based approach to pipe replacement that the Company has employed over the past 12 years, most of the high-risk mains and services should already have been replaced. In fact, the Company admits that gas leak data shows a downward trend. As expected, the Company stated in response to discovery that as the pipe continues to age the number of gas leaks will increase.[36]

However, this is a conclusion without any engineering analysis. The Company has not provided any compelling evidence that a three-to-five-year extension of the program will result in a material increase in gas leaks or larger infiltration of water in gas pipes above

[36] Exhibit AG-9 includes DR AG-CE-0389 and 0780.

recent historical levels. Also, there is no evidence that the planned increase in spending in recent years and for the projected test year is tied to any increased safety risks. Therefore, if the completion of the EIRP program is extended a few more years past the current 2035 date, it is a reasonable trade-off to balance against customer affordability from uncontrolled capital spending on the program.

I recommend that the Commission approve the disallowance of $84,889,000 from the Company's forecasted capital expenditures of the projected test year and establish a spending budget for the EIRP of $197 million to be adjusted for the CPI rate of inflation in future years.

**6. Material Condition Non-Modeled Program**

As shown on page 1 of Exhibit A-82 (KAP-4), the Company forecasted capital expenditures for the Material Condition Non-Modeled Program of $38.3 million for 2024, $36.4 million for the 10 months ending October 2025, and $56.2 million for the 12 months ending October 2026. In comparison the Company spent $38.5 million in 2023.

Ms. Pascarello discusses this program beginning on page 50 of her direct testimony. In contrast with the EIRP, which is a planned replacement of deteriorating pipelines and services, the Material Condition Non-Modeled program addresses emergent needs for pipe replacement and other work that arise during the course of the year. Beginning in 2024, the Company expanded this capital program to undertake the replacement of wrought iron mains, replacement of high-pressure mains at water crossings, leak mitigation activities,

and replacing obsolete meters. Of the $17.7 million increase in spending in the projected test year over 2023, $5.0 million pertains to the replacement of wrought iron mains, $5.0 million is for HP mains in water crossings, $4.0 million for leak mitigation, and $3.7 million to replace obsolete meters.[37]

**Q. WHAT IS YOUR ASSESSMENT OF THE COMPANY'S PROPOSED CAPITAL SPENDING ON THE MATERIAL CONDITION NON-MODELED PROGRAM?**

A. There are several issues that arise after revieing the Company's proposed spending and expansion of the program from the basic emergent problems that arise during the year that need to be addressed.

Wrought Iron Mains - It seems that the Company has expanded the non-modeled program to supplement the EIRP for work that should be done within that program. The replacement of wrought iron mains is one such case. Wrought iron mains are similar to cast iron mains that the Company has been replacing within the EIRP. Replacement of those mains should be included in the EIRP and prioritized against other projects for risk and replacement. Therefore, the forecasted capital expenditures of $1.5 million for 2025 and $5.0 million for 2026 should be removed from the non-modeled program.[38] The amount to remove for the 10 months ending October 2025 is $1,250,000 ($1.5 million x 10/12) and the amount to remove for the projected test year is $4,417,000.[39]

[37] Kristine Pascarello's direct testimony at page 51.
[38] Exhibit AG-10 includes DR AG-CE-0393, 0397, 0782, and 0785.
[39] $5,000,000 x 10/12 + $1,500,000 x 2/12 - $4,417,000.

HP Water Crossing Mains - Regarding the HP main water crossing projects, in discovery the Attorney General asked the Company to provide the phase of project development in addition to other pertinent information. The information provided in response to the request shows that eight projects are still in the scoping phase and 2 projects are beginning to enter the design phase.[40] The total capital expenditures for the 10 projects are $500,000 for the 10 months ending September 2025, and $5.0 million for the projected test year. These projects are still in the early stage of development and premature to be included in rate base in this rate case. Therefore, I recommend that the $500,000 and $5.0 million be removed from the Company's forecasted capital expenditures for the applicable forecasted periods.

Risk Mitigation and Obsolete Meter Replacement – Ms. Pascarello's direct testimony is devoid of any explanation or supporting evidence to justify either of these two spending categories. The only mention for the two items is on page 51 of her testimony to identify the amount of cost variance between the projected test year and the 2023 spending. As shown in the table in DR AG-CE-0782 (Exhibit AG-10), capital spending for Risk Mitigation begins in 2024 at $2,971,000, followed by $250,000 in 2025, and $4,000,000 in 2026. There is no support for these capital expenditures. Therefore, I recommend that the Commission remove the $2,970,000 for 2024, $208,000 for the 10 months ending

[40] Exhibit AG-10 includes DR AG-CE-0787.

October 2025 ($250,000 x 10/12), and $3,375,000 for the 12 months ending October 2026.[41]

Similarly, for Obsolete Meter project, there is no testimony supporting the $3.7 million in forecasted capital spending in 2026. Therefore, I recommend that the Commission remove $3,083,000 for the 12 months ending October 2026 ($3,700,000 x 10/12).

Line 1010 MAOP Project – Beginning on page 55 of her direct testimony, Ms. Pascarello discloses that the forecasted capital expenditures for Material Condition Non-Modeled include the cost to replace Line 1010 in the amount of $10,300,000 for 2024, $14,900,000 for 2025, and $12,800,000 for 2026. This line is a MAOP project similar to the other projects discussed earlier in my testimony, which instead is being done under the Material Condition Non-Modeled program. As stated in her testimony, the reason to replace this line is the Company's incomplete pressure test documentation and lack of other traceable, verifiable, and complete records from the original installation of the pipeline. Although this pipeline was purchased from another utility, the responsibility to maintain complete, accurate and adequate records still falls on the Company and customers should not pay the full cost to replace the pipeline due to those failures.

Therefore, I recommend that the Commission disallow 50% of the cost to replace this pipeline. In response to discovery, the Company disclosed that it included capital expenditures of $10,300,000 in the 10 months ending October 2025 and $9,300,000 in the

[41] $4,000,000 x 10/12 - $250,000 x 2/12 = $3,375,000.



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projected test year.[42] Based on those amounts and the 2024 amount previously identified by the Company, I recommend that the Commission disallow $5,150,000 for 2024, $5,150,000 for the 10 months ending October 2025 and $4,650,000 for the projected test year. These amounts represent 50% of the total capital expenditures identified by the Company for the applicable periods.

**Q. WHAT IS YOUR OVERALL RECOMMENDATION FOR ADJUSTMENTS TO THE COMPANY'S FORECASTED CAPITAL EXPENDITURES FOR THE MATERIAL CONDITION NON-MODELED PROGRAM?**

A. As discussed above, I recommend that the Commission remove $8,121,000 for 2024, $7,108,000 for the 10 months ending October 2025, and $20,525,000 for the projected test year from the Company's forecasted capital expenditures.

**7. Material Condition - Renewal Program**

As shown on page 1 of Exhibit A-82 (KAP-4), the Company forecasted capital expenditures for the Material Condition – Renewal Program of $31.9 million for 2024, $30.7 million for the 10 months ending October 2025, and $33.2 million for the 12 months ending October 2026. In comparison the Company spent $31.8 million in 2023.

In my analysis I found the capital expenditures proposed by the Company for this program to be reasonable. However, as described in pages 64 and 65 of Ms. Pascarello's direct

[42] Exhibit AG-10 includes DR AG-CE-0398.

testimony, the Company had anticipated that PHMSA would be issuing a new Leak Detection and Repair (LDAR) rule in early 2025 that would potentially increase the number of leak repairs that the Company would need to undertake. To address this increase in workload, the Company forecasted $1.5 million of additional capital expenditures for the projected test year under the Renewals program.

In response to discovery, the Company stated that the new rule is currently on hold falling under the Presidential Executive Order that placed all new regulations on hold pending further review. As a result, it is unlikely that the new LDAR rule will be issued in the near future and require the Company to undertake additional leak repair work in the projected test year. Therefore, I recommend that the Commission remove the $1.5 million from the Company's forecasted capital expenditures for the projected test year.

**8. Vintage Services Replacement Program**

As shown on page 1 of Exhibit A-82 (KAP-4), the Company forecasted capital expenditures for the Vintage Service Replacement Program of $18.7 million for 2024, $25.9 million for the 10 months ending October 2025, and $42.5 million for the 12 months ending October 2026. In comparison the Company spent $11.4 million in 2023.

Ms. Pascarello discusses this program beginning on page 66 of her direct testimony. This program replaces deteriorating service lines outside of the EIRP. Beginning in 2022, the Company began to align replacement of vintage services with the replacement of mains under the EIRP to avoid duplicating work by replacing services before the associated

mains were replaced. From Table 9 on page 71 of Ms. Pascarello's testimony, it appears that this effort resulted in fewer non-EIRP services replacements in 2022, 2023, and 2024. Where in the three years prior to 2022, the Company replaced more than 5,000 service under the VSR program annually, in 2022 the forecasted number declined to 2,176, and in 2023 it declined further to 1,228 services. In response to discovery, the Company reported that the actual number of services replaced in 2024 was 2,564.[43]

However, for 2025, the Company forecasted an increase of 64% to 4,194 services. For 2026, the forecasted the number of services to be replaced under the VSR program increases further to 5,913 units for a cumulative increase of 131% from the number completed in 2024. These forecasted quantities are excessive and go counter to the declines observed in 2022 through 2024. From the discussion in Ms. Pascarello's testimony, it is not clear why a resumption of a large replacement program is necessary other than meeting an arbitrary program completion date. For example, the gas leak data provided on page 67 of her testimony shows a slight uptick in the number of gas leaks in 2024 from 2023 but an overall declining trend for all types of gas services in the past three to four years. The higher number of service replacements is not adequately supported and should be scaled back.

While I would normally recommend the use of the average number of services replaced in the most recent three-year 2022 through 2024, which would be 1,989 services, to facilitate a more expeditious replacement of the remaining vintage services, I propose that the actual

[43] Exhibit AG-11 includes DR AG-CE-0793 with attachment.



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number of services replaced in 2024 of 2,564 be used to forecast capital expenditures for 2025 and 2026. It is reasonable to conclude that the 2024 VSR program replacement rate reflects the Company's most recent effort and commitment to the program. Based on the unit costs for 2025 and 2026 shown in Table 9 on page 71 of Mr. Pascarello's direct testimony, I arrived at forecasted capital expenditures of $17,104,000 for 2025 and $14,254,000 for the 10 months ending October 2025 ($17,104,000 x 10/12). I calculated capital expenditures of $18,945,000 for 2026, and $18,638,000 for the projected test year.[44]

Based on those calculations, I recommend that the Commission remove the excessive capital expenditures of $11,631,000 for the 10 months ending October 2025 and $23,875,000 for the 12 months ending October 2026.[45]

## 9. Compliance & Controls Projects

On page 1 of Exhibit A-83 (KAP-5), the Company included forecasted capital expenditures for Compliance and Controls Projects of $4.9 million for 2024, $447,000 for the 10 months ending October 2025, and $4.2 million for the 12 months ending October 2026. Included in these amounts are capital expenditures for the Advanced Methane Detection (ADM) system and the Enterprise Corrective Action Plan, which I will discuss below and propose certain adjustments.

[44] 2025: 2,564 units x $6,671 = $17,104,000 x 10/12 = $14,254,000. For 2026: 2,564 units x $7,389 = $18,945,000 x 10/12 + $14,254,000 x 2/12 = $18,638,000.
[45] $14,254,000 - $25,885,000 = -$11,631,000 and $18,638,000 - $42,513,000 = -$23,875,000.

As shown in Table 10 on page 73 of Ms. Pascarello's direct testimony, the Company forecasted capital expenditures for the ADM system of $4,650,000 for 2024, $265,000 for 2025, and $3,181,000 for the projected test year. The Company began phase 1 implementation of the AMD system in 2021 and completed it in 2022 for a total capital cost of $7,035,000.[46] Based on information disclosed in the prior rate case No. U-21490, Phase 2 of the project was to start in 2023. Based on the information provided in Table 10, it appears that Phase 2 was delayed to 2024.

On pages 73 through 80 of her direct testimony, Ms. Pascarello discusses the features of the ADM system and the purported ability of the system to detect very small gas leaks that current equipment supposedly cannot detect.

**Q. WHAT IS YOUR ASSESSMENT OF THE AMD PROJECT?**

A. At a cost of more nearly $15 million, assuming no further costs past 2026, the AMD system is a very costly project. Despite the Company's claims and self-serving information gathered from the marketing brochures from the vendor, there is insufficient evidence that the new system will detect significant additional gas leaks of a threatening nature that are currently missed by existing equipment. As I stated in my testimony in Case No. U-21490, in response to discovery, the Company stated that it has not had problems identifying true gradable gas leaks using its existing traditional leak detection tools. Asked to provide quantifiable evidence of the value proposition of the new system, the Company provided

[46] U-21490 Exhibit AG-10 includes DR AG-CE-0373 ATT_1.

a general statement that the AMD increases public safety without providing any evidence to support that statement and stating that value propositions have not been quantified.[47]

Since Case No. U-21490, the Company performed a field test of the AMD equipment during 2024 and reported that the AMD equipment found one gas leak for every 4.8 miles surveyed, while the existing leak detection equipment found one gas leak for every 33.3 miles surveyed.[48] While the test would indicate that the new equipment would find more gas leaks, it does not show that any of the additional found gas leaks are of great concern. In discovery, the Attorney General asked the Company to provide the grade of the additional gas leaks found by the ADM equipment. In response, the Company stated that the test did not capture this important information.[49] The Company grades gas leaks by level of severity. A Grade 1 leak is considered an immediate action leak and is escalated for immediate remediation. A Grade 2 leak is scheduled for remediation within 6 months. A Grade 3 leak is either remediated within 12 months or monitored annually to ensure the leak has not increased in severity where it would pose a safety risk.[50] Most likely the ADM equipment found more Grade 3 leaks, which are of very low priority that certainly do not justifying nearly $15 million in new equipment.

Furthermore, the ADM is not replacing existing leak detection equipment. According to the Company, the ADM identifies only a general area where a gas leak may exist. The Company than must use traditional gas leak detection equipment to pinpoint whether an

[47] Id. includes DR AG-CE-0370.
[48] Exhibit AG-12 includes DR AG-CE-0417
[49] Id. includes DR AG-CE-0794.
[50] Id. includes DR AG-CE-0471.



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actual gas leak is occurring and from where it is occurring.[51] Therefore, the ADM system is at best of marginal benefit. There has been no evidence presented by the Company that the existing leak detection is missing serious and dangerous gas leaks that is placing customers and the public in danger or that large quantities of natural gas are escaping into the atmosphere that pose a large financial loss or environmental hazard.

Although Ms. Pascarello references discussions with other utilities who have acquired the system, when asked to describe what value these utilities have garnered from the new system, her response was that the Company has not engaged in conversations with peer utilities about AMD cost/benefits or value decisions.[52] It is astonishing that the Company would propose to invest nearly $15 million in a new system without performing basic due diligence to determine that the system actually provides incremental value.

In her testimony, Ms. Pascarello claims that the AMD will be required under the PHMSA Advisory Bulletin. However, as discussed above, the proposed LDAR rule has been placed on hold with no indication if and when it may be issued.[53]

**Q. WHAT IS YOUR CONCLUSION AND RECOMMENDATION?**

A. Given the high cost of the project, the lack of supporting evidence that a problem exists that must be solved, and only marginal benefits, I recommend that the Commission reject the Company's proposed capital expenditures for the AMD system of $4,650,000 for 2024,

[51] Id. includes DR AG-CE-041, 0418, and 0419.
[52] U-21490 Exhibit AG-10 includes DR AG-CE-0371.
[53] Exhibit A-12 includes DR AG-CE-0405.

$221,000 for the 10 months ending October 2025, and $3,181,000 for the 12 months ending October 2026.

**Q. PLEASE DISCUSS YOUR CONCERNS WITH THE PROPOSED SPENDING ON THE ENTERPRISE CORRECTIVE ACTION PROGRAM.**

A. In Table 10 on page 73 of her direct testimony, Ms. Pascarello identified capital spending for the Enterprise Corrective Action Program (ECAP) of $49,000 in 2023, $204,000 for 2024, $200,000 for 2025 and $33,000 for the projected test year. On pages 80 and 81 of her testimony, Ms. Pascarello briefly discusses the program and the proposed capital expenditures. From the testimony, it is not clear what the capital spending is for and what benefits those expenditures and the program have achieved or will achieve. In discovery, the Attorney General asked the Company to explain specifically what the capital spending in each of the four phases of the ECAP implementation have accomplished or will accomplish. The discovery request also asked the Company to identify what the systems in Table 12 are used for, have accomplished or will accomplish.

In response to the first question, the Company mentions implementation of a corrective and preventive action system to collect information, identify issues, and take timely action to resolve and sustain resolutions in various departments of the Company. Other than boilerplate statements, it is not clear what problems exist that the Company is trying to resolve by implementing a new system to gather information it should already have. The response to the second questions basically repeats the statements in the first answer with

more jargon and general concepts. No problems, likely solutions, or potential benefits achieved or to be achieved were identified.[54]

Given the unsupported capital spending in this area, I recommend that the Commission remove all capital expenditures from 2023 through the projected test year. These amounts include $49,000 for 2023, $204,000 for 2024, $167,000 for the 10 months ending October 2025 ($200,000 x 10/12), and $33,000 for the projected test year.

**Q. WHAT IS YOUR OVERALL RECOMMENDATION FOR ADJUSTMENTS TO THE COMPANY'S FORECASTED CAPITAL EXPENDITURES FOR COMPLIANCE AND CONTROLS PROJECTS?**

A. As discussed above, I recommend that the Commission remove $49,000 for 2023, $4,854,000 for 2024, $488,000 for the 10 months ending October 2025, and $3,214,000 for the projected test year from the Company's forecasted capital expenditures.

**10. Geospatial Inventory and Modelling Program**

On page 1 of Exhibit A-83 (KAP-5), the Company included forecasted capital expenditures for the Geospatial Inventory & Modelling Program of $5.8 million for 2024, $8.3 million for the 10 months ending October 2025, and $7.5 million for the 12 months ending October 2026. Included in these amounts are capital expenditures for the Utility Network project, which I will discuss below and propose certain adjustments.

[54] Exhibit AG-13 includes DR AG-CE-0425.

As shown in Table 14 on page 85 of Ms. Pascarello's direct testimony, the Company forecasted capital expenditures for the Utility Network project of $2,888,000 for 2024, $10,970,000 for 2025, and $4,866,000 for the projected test year. In total, from 2024 to 2026, the Company forecasted capital spending of $18.7 million for the project. Additionally, from 2023 through 2026, the Company forecasted O&M expenses of $3.1 million for a total project cost of $21.8 million.

On pages 84 through 86 of her testimony, Ms. Pascarello describes the Utility Network as a transformation of the Company's current Geospatial Information Systems (GIS) into a unified system and data model for gas transmission, distribution, and stations to support engineering needs, operational processes, technologies and data. She states that managing the current models is becoming a challenge and the existing software will not be supported by the vendor starting in 2026 for some subsystems and later for other systems. She also listed purported potential benefits or value that will be created by the new system, such has mitigating risks, increase productivity, providing more asset visibility, and other opaque features that seem to be sourced from a vendor marketing brochure.

**Q. WHAT IS YOUR ASSESSMENT OF THE GAS UTILITY NETWORK PROJECT AND THE RELATED FORECASTED CAPITAL EXPENDITURES?**

A. In discovery, the Attorney General asked the Company to provide some additional information on the project, including the current phase of the project, whether the detailed requirements phase has been completed, what additional features and functionality the new system provided that are not provided by the current system that are critically necessary,

and a copy of the cost/benefit analysis for the project that would provide economic support to undertake the project.

In response, the Company stated that it has begun implementing some early aspects of the system and is still defining many detailed system requirements with the start of the project delayed somewhat. Several of the additional functionality supposedly provided by the new system relate to quicker turnaround of information or visibility of data which point to work efficiency. Other seem to relate to better management and improved processes which can be achieve with any system either new or old. Most importantly, given the purported increase work efficiencies, the Company did not prepare a cost/benefit analysis to identify economic benefits from the new system.[55] Instead, the Company basis its decision to undertake this costly project primarily on the obsolescence of and lack of vendor support for the existing system in future years.

**Q. WHAT IS YOUR CONCLUSION AND RECOMMENDATION REGARDING THE COMPANY'S FORECASTED CAPITAL EXPENDITURES FOR THE UTILITY NETWORK PROJECT?**

A. The marginal improvement in functionality and lack of a cost/benefit analysis do not support undertaking the Utility Network project at a cost of approximately $22 million, including O&M expenses. Therefore, I recommend that the Commission remove $2,888,000 for 2024, $10,255,000 for the 10 months ending October 2025, ($12,306,368

[55] Exhibit AG-14 includes DR AG-CE-0427 with attachment.

x 10/12), and $7,513,000 for the projected test year from the Company's forecasted capital expenditures. Later in my testimony, I will address the disallowance of the O&M expense portion of the project.

## B. Transmission Plant - Capital Expenditures

In Exhibit A-12 (MPG-2), Schedule B-5.5, the Company shows forecasted capital expenditures for Transmission Plant of $313.8 million for 2024, $176.8 million for the 10 months ending October 2025, and $219.9 million for the 12 months ending October 2026. In comparison, the Company spent $350.6 million in 2023. The three programs within the Transmission area are Asset Relocation, Regulatory Compliance, and Capacity/Deliverability. In my testimony below, I propose adjustments to the capital expenditures in several areas.

### 1. Pipeline Integrity –TOD

**Q. PLEASE DISCUSS THE COMPANY'S PROPOSED TRANSMISSION INTEGRITY WORK AND THE RELATED CAPITAL EXPENDITURES.**

A. On page 1 of Exhibit A-60 (MPG-4), the Company shows forecasted capital expenditures for Pipeline Integrity work for Transmission Operated by Distribution (TOD) of $6.1 million for 2024, $5.6 million for the 10 months ending October 2025, and $10.0 million for the projected test year. On page 22 of his direct testimony, Mr. Michael Griffin briefly discusses the capital expenditures forecasted by the Company for the bridge periods and the projected test year. He points to new requirements for Internal Corrosion Direct

Assessments (ICDA) beginning in 2023 and increased excavations as a result of the new requirements. He also states that the installation of Ultrasonic Thickness ("UT") sensors during prior assessments will reduce the number of future excavations. Mr. Griffin provided no other details about activities, and work volumes to support the forecasted capital expenditures for TOD pipeline integrity work.

In discovery, the Attorney General asked the Company to provide additional details and support for the level of work activity by year to justify the forecasted capital spending. In response, the Company provide a table identifying six different components to the pipeline integrity program with capital expenditures for 2023 through 2026 sourced from workpapers. In a subsequent discovery response, the Company provided also the number of High Consequence Area (HCA) miles to be assessed and other risk mitigation miles to also to be assessed from 2021 through 2026.[56]

This information shows that External Corrosion Direct Assessments (ECDA) and ICDA costs for the forecasted periods are generally in line with historical expenditures. However, the Company included a new category of costs, called Casings, beginning in 2024 with capital expenditures of $178,000, which escalate to $2.0 million annually in 2025 and 2026. Similarly, the Company included a new item, called Risk Mitigation in 2024 with actual capital expenditures of $578,000, well below the $1,665,000 forecasted for the year. Capital expenditures for this item declines to $661,000 in 2025 and then

[56] Exhibit AG-15 includes DR AG-CE-0316 Revised and 0748 with attachment.

jumps to $4,866,000 in 2026. The large swings in spending in this area are perplexing for a program that should consistently mitigate risk.

The discovery response states that casing assessments are done every seven years. However, the Company forecasted capital expenditures have them repeating two years in a row at the same amount of $2.0 million. These amounts appear to be ballpark amounts with no specific quantification of the forecasted cost. In response to additional discovery, the Company stated that it has very limited experience with the cost of inspecting and remediating casings. Furthermore, it disclosed that the casing projects are still in the planning and scheduling phase, which is in the early phase of project development.[57] From this information, I concluded that at least the 2026 projects are premature to include in rate base in this rate case. Therefore, I recommend that only the 2025 amount be approved and the 2026 forecasted cost be removed. This results in an adjustment of $2.0 million for the projected test year.

The risk mitigation work pertains to assessing and remediating non-HCA pipe. The Company inspected and mitigated 18 miles in 2024 at a cost of $578,000. For 2025, it has forecasted to double the number of miles to 34 at a cost of $661,000, which seems reasonable. However, for 2026, the Company proposes to triple the number of miles to be assessed and remediated to 105 from the number in 2025 at a cost of $4,866,000. The large increase in both the number of miles and cost is excessive and has not been supported or justified. Furthermore, in response to discovery, the Company stated that the Risk

[57] Id. includes DR AG-CE-0329.

Mitigation work was still in the planning and scheduling phase, making the entire costs uncertain and premature to include in rate base in this rate case.[58]

Therefore, I propose that at most a doubling of the number of miles and cost of $661,000 from 2025 to $1,322,000 in 2026 is more appropriate and reasonable. This 2026 amount is $3,544,000 lower than the amount proposed by the Company. I recommend that the Commission remove $2,953,000 ($3,544,000 x 10/12) from the Company's forecasted capital expenditures for the projected test year.

In summary, I recommend that the Commission reduce the Company's forecasted capital expenditures for the projected test year for TOD Pipeline Integrity by $4,953,000.

**2. Regulatory Compliance – Transmission MAOP Projects**

**Q. PLEASE DISCUSS THE COMPANY'S PROPOSED TRANSMISSION MAOP PROJECTS AND RELATED CAPITAL EXPENDITURES.**

A. On page 1 of Exhibit A-60 (MPG-4), the Company shows forecasted capital expenditures for MAOP Compliance for Transmission Pipelines of $51,000 for 2024, $2.4 million for the 10 months ending October 2025, and $3.0 million for the projected test year. In workpaper WP-MPG-2, the Company lists the projects and related dollars that make up the 2023 actual spending and the total forecasted capital expenditures for future periods.[59]

[58] Id.
[59] Exhibit AG-16 includes WP-MPG-2.



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Beginning on page 24 of his direct testimony, Mr. Griffin discusses the various activities under the Regulatory Compliance Program, including the replacement of transmission pipeline under MAOP projects. The issues here are the same as in the Distribution MAOP projects. The Company lacks traceable, verifiable, and complete records to re-establish the MAOP of the targeted pipelines and has decided to replace those pipelines or segments of pipelines. As stated earlier in my testimony under the Distribution MAOP projects, customers should not pay for the entire cost to replace the affected pipeline because of the failure by the Company to have and maintain accurate and complete records on its pipelines.

In response to discovery, the Company stated that Project GL-03042 in WP-MGP-2 is not required at this time.[60] Therefore, the capital expenditures of $1,692~~,000~~ for 2023 and $1,799~~,000~~ for 2024 can be removed from rate base in this rate case in their entirety. In response to an additional discovery request, the Company confirmed that capital expenditures of $2,564,000 for the projected test year pertains to currently unknown projects.[61] This amount has been included as a placeholder and should be removed. As stated earlier, the Commission has rejected the inclusion of placeholder amounts in rate base.

Regarding the remaining projects listed in WP-MGP-2, the capital expenditures for those projects total to $4,419,000 for 2023, $708,000 for 2024, $2,409,000 for the 10 months

[60] Id. includes DR AG-CE-0750.
[61] Id. includes DR AG-CE-0331.

ending October 2025, and $452,000 for the projected test year. As discussed above, I recommend that the Commission disallow recovery of 50% of the proposed capital expenditures. Therefore, the Commission should remove capital expenditures of $2,210,000 for 2023, $354,000 for 2024, $1,205,000 for the 10 months ending October 2025, and $226,000 for the projected test year.

In total, for the projects listed in WP-MPG-2, I recommend that the Commission remove capital expenditures of ~~$3,902,000~~$2,212,000 for 2023, ~~$2,153,000~~$356,000 for 2024, $1,205,000 for 10 months ending October 2025, and $2,790,000 for the projected test year.

**3. Asset Relocations**

On page 1 of Exhibit A-59 (MPG-3), the Company included forecasted capital expenditures for Asset Relocation projects of $17.4 million for 2024, $19.1 million for the 10 months ending October 2025, and $24.7 million for the projected test year. In comparison, the Company spent $6.2 million in 2023. In workpaper WP-MPG-1, the Company provides the list of projects that comprise the total forecasted capital expenditures.[62]

In response to discovery, the Company reported that three of the listed projects in WP-MPG-1 are still in the preliminary design phase. The projects are GL-00990 KZO 1200A Wetland, GL-00991 KZO 1200A Townline Rd., and GL-02086 KZO 1200A Needham Rd. The total capital expenditures for the three projects are $129,000 for the 10 months

[62] Exhibit AG-17 includes WP-MPG-1.

ending October 2025 and $15,456,000 for the projected test year.[63] These projects are still in the early stage of development with no design completed or significantly advanced. The cost level and timing of the capital expenditures is still uncertain and premature to include in rate base in this rate case.

Therefore, I recommend that the Commission remove $129,000 for the 10 months ending October 2025 and $15,456,000 for the projected test year from the Company's forecasted capital expenditures.

**4. Deliverability Field Measurement Projects**

**Q. PLEASE DESCRIBE YOUR FINDINGS WITH REGARD TO THE CAPITAL EXPENDITURES PROPOSED BY THE COMPANY FOR DELIVERABILITY FIELD MEASUREMENT PROJECTS.**

A. On line 3 of page 1 of Exhibit A-61 (MPG-5), the Company included forecasted capital expenditures for Field Measurement projects of $6.8 million for 2024, $10.3 million for 10 months ending October 2025, and $19.9 million for the projected test year. In comparison, the Company spent $5.3 million in 2023. In workpaper WP-MPG-3, the Company provided the list of projects that comprise the total capital expenditures.[64] Beginning on page 39 of his direct testimony, Mr. Griffin describes the program activities, lists the major projects, and points to the Company's goals of improving gas measurement

[63] Id. includes DR AG-CE-0326.
[64] Exhibit AG-18 includes WP-MPG-3.

accuracy and reducing lost and unaccounted for (LAUF) gas in support of the capital spending in this area.

In discovery, the Attorney General asked the Company to provide more pertinent information on the larger projects, such as the current phase of project development, the project cost/benefit analysis, what the capital dollars will be spent on, what the project entails, and why it is necessary. In response, the Company reported that most projects are in the early stage of design or design work has not yet started and will not start until later in 2025 or 2026. The Company also reported that no cost/benefit analyses were prepared for any of the projects. Other issues are discussed below for specific projects.[65]

GM-01047 JXN-Lainsburg Jnc. Meter Installation: Based on the information provided in WP-MPG-3, this project entails the installation of a new meter at a total cost of $4.4 million with capital expenditures of $3,119,000 for the 10 months ending October 2025 and $378,000 in the projected test year. The Company explains that the new meter is needed to improve gas measurement accuracy. No specific problem has been identified with the current meter and no specific benefits were identified other than vague statements of improved metering accuracy for reducing LAUF gas. No cost/benefit analysis was performed. Given the inadequate support provided for this project, I recommend that the Commission remove the $3,119,000 for the 10 months ending October 2025 and $378,000 in the projected test year from the Company's forecasted capital expenditures.

[65] Id. includes DR AG-CE-0332 with ATT_1.



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GM-01089 Williamston Transmission Meter Proving Station: This project requires the construction of a new testing facility to prove and test transmission meters before installation for compliance to API-1164. The total cost of this facility is at least $9.4 million with $226,000 included in forecasted capital expenditures for the 10 months ending October 2025 and $7,994,000 in the projected test year. The Company currently uses a third-party testing facility. No cost/benefit analysis was performed by the Company to justify this project and bring the work in-house. In an attempt to identify some cost savings in Attachment 2 of DR AG-CE-0332 (Exhibit AG-18), the Company listed certain items with related dollar amounts that it calls "1st Year Anticipated Capital Efficiencies." The first item is supposedly a cost savings of $100,000 by building the facility with Company resources. However, the Comparison here should be to the cost of third-party services and not to building a facility with Company resources versus using contractor resources. This would be a second step analysis after building a new facility is justified versus continuing to use a third-party service provider. The second items for $50,000 may be a legitimate savings but there is no comparison to the current cost for the service provided by the third-party versus the Company performing that function on its own. The analysis is incomplete.

The third item for a purported savings of $750,000 is difficult to understand even after further explanation was requested in DR AG-CE-0758.[66] The Company wants to buy its own tools and equipment to construct multiple gas analysis buildings. This appears to be

[66] Id. include DR AG-CE-0758.



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an added cost not a savings versus using the third-party service. The fourth item could be a cost savings but needs to be compared to the cost of building and operating the new facility, which the Company has not done. In other words, the Company has not performed a serious cost/benefit analysis to justify building and operating this new facility. Therefore, I recommend that the Commission remove the $226,000 included in forecasted capital expenditures for the 10 months ending October 2025 and the $7,994,000 in the projected test year.

B-GM-00041 Rose Center Meter Replacement: This project entails another meter replacement on the premise that the current meter has reached the end of its useful life. The forecasted capital expenditures for this project are $302,000 for the 10 months ending October 2025 and $818,000 for the projected test year. No specific problems were identified with the current meter. No cost/benefit analysis was performed, and no other benefits have been quantified for LAUF gas accuracy improvements, etc. No design work has yet begun on this project with the expectation that design work would start sometime in the second quarter of 2025. Aside for the project still being in the early stage of development and all the related uncertainty with cost and timing of capital expenditures that such an early-stage project entails, the project has not been adequately justified. Therefore, I recommend that the Commission remove the forecasted capital expenditures of $302,000 for the 10 months ending October 2025 and $818,000 for the projected test year from this rate case.

The following six projects: B-GM-00042, B-GM-00043, and B-GM-00045 through B-GM-00048 do not have any design work completed, and design work would not start until late in the third quarter of 2025, near the end of 2025, or in 2026. Given the early stage of development, it is premature to include the capital expenditures for these projects in rate base in this rate case. The total capital expenditures forecasted by the Company for the six projects are all in the projected test year for $8,369,000. I recommend that the Commission remove this amount from the forecasted capital expenditures in this rate case.

**Q. WHAT IS YOUR OVERALL RECOMMENDATION FOR ADJUSTMENTS TO THE COMPANY'S FORECASTED CAPITAL EXPENDITURES FOR FIELD MEASUREMENT PROJECTS?**

A. As discussed above, I recommend that the Commission remove $3,647,000 for the 10 months ending October 2025, and $17,559,000 for the projected test year from the Company's forecasted capital expenditures.

**5. Deliverability Base Pipeline Program**

**Q. PLEASE DESCRIBE YOUR FINDINGS WITH REGARD TO THE CAPITAL EXPENDITURES PROPOSED BY THE COMPANY FOR THE DELIVERABILITY BASE PIPELINE PROGRAM.**

A. On line 4 of page 1 of Exhibit A-61 (MPG-5), the Company included forecasted capital expenditures for the Deliverability Base Pipeline program of $18.2 million for 2024, $19.4 million for 10 months ending October 2025, and $25.0 million for the projected test year.

In comparison, the Company spent $18.8 million in 2023. In workpaper WP-MPG-4, the Company provides the list of projects that comprise the total forecasted capital expenditures.[67] In response to discovery, the Company provided additional details for select larger projects, such as the current phase of development as of early April 2025.

Discovery response AG-CE-0333 shows that work on Project B-GL-00251 has been cancelled. Based on WP-MPG-4, the forecasted capital expenditures for this project were $1,561,000 for the 10 months ending October 2025 and $230,000 for the projected test year. In the discovery response, the Company states the cancelled project was replaced by another project.[68] However, insufficient information is available on the new project to make a full assessment of the prudency of the forecasted cost to be incurred. Therefore, I recommend that the capital expenditures forecasted for the cancelled project be removed from this rate case.

The discovery response also identified 11 projects where no work has yet been done, and no design work has been initiated or completed. The 11 projects are: B-GL-00259 through B-GL-00267, B-GL-00280, and GL-03047.[69] Based on the information provided in WP-MPG-4, the total capital expenditures for the 11 projects for the projected test year are $18,466,000. These projects are still in the early phase of development with no assured timeline and thus premature to include in rate base in this rate case. Therefore, I

[67] Exhibit AG-19 includes WP-MPG-4.
[68] Id. includes DR AG-CE-0333.
[69] Id.

recommend that the Commission disallow $18,466,000 of capital expenditures for the projected test year.

In total for this program, I recommend that the Commission remove $1,561,000 for the 10 months ending October 2025 and $18,696,000 for the projected test year from the Company's forecasted capital expenditures.

## 6. T&S City Gate Projects

**Q. PLEASE DESCRIBE YOUR FINDINGS WITH REGARD TO THE CAPITAL EXPENDITURES PROPOSED BY THE COMPANY FOR CITY GATE PROJECTS.**

A. On line 6 of page 1 of Exhibit A-61 (MPG-5), the Company included forecasted capital expenditures for T&S City Gates of $52.9 million for 2024, $47.5 million for 10 months ending October 2025, and $59.0 million for the projected test year. In comparison, the Company spent $31.3 million in 2023. In workpaper WP-MPG-6, the Company provided the list of projects that comprise the total capital expenditures.[70] In response to discovery, the Company provided the cost of each project undertaken each year in 2022 through 2024 and the forecasted cost of projects planned for 2025 and 2026. The Company also provided the phase of development of the planned projects as of early April 2025.[71]

[70] Exhibit AG-20 includes WP-MPG-6.
[71] Id. includes DR AG-CE-0335 and 0753 with attachments.

Attachment 1 to discovery response AG-CE-0753 (Exhibit AG-20) shows the individual projects and related cost by year. For the historical three years 2022-2024, I calculated an average cost per project of $6,093,000. Adjusted for inflation, the cost for 2025 is $6,239,000 and for 2026 is $6,395,000. In comparison, for the 2025 projects, the Company has forecasted a cost per project of $7,404,000. This amount is nearly 19% over the inflation adjusted cost for 2025. Similarly, the Company's 2026 forecasted cost per project is $7,757,000, or 21% above the inflation adjusted cost for the year. These large increases in project costs are excessive and need to be moderated.

I will also point out that most of the 2025 and 2026 planned projects are still in the engineering/design phase or in pre-engineering and design. Therefore, it is very likely that the cost for these projects will change from the amounts proposed by the Company and the timing of construction could slip into a future year.

To develop a reasonable forecast of capital expenditures for T&S Gate Stations, I have applied the 2025 inflation adjusted cost of $6,239,000 to the 7 projects planned by the Company. The result is a capital expenditures amount of $43,673,000 for 2025 or $36,394,000 for the 10 months ending October 2025 ($43,673,000 x 10/12). This amount is ~~$11,074,000~~$4,196,000 lower than the ~~$47,469,000~~$40,590,000 forecasted by the Company. For 2026, I multiplied the project cost of $6,395,000 by the 7 projects planned for the year to arrive at forecasted amount of $44,765,000. The forecasted amount for the projected test year is $44,583,000. This amount is ~~$14,408,000 lower~~$3,607,000 higher than the ~~$58,991,000~~$40,976,000 forecasted by the Company.

Therefore, I recommend that the Commission remove ~~$11,074,000~~$4,196,000 for the 10 months ending October 2025 and ~~$14,408,000~~ add $3,607,000 for the projected test year from the capital expenditures forecasted by the Company.

## 7. Remote Control Valves (RCV)

**Q. PLEASE DISCUSS WHAT ADJUSTMENTS YOU ARE PROPOSING TO THE CAPITAL PROJECTS FOR RCV PROJECTS.**

A. On page 1, line 3, of Exhibit A-62 (MPG-6), the Company forecasted capital expenditures for RCV projects of $8.7 million for the 10 months ending October 2025, and $18.1 million for the 12 months ending October 2026. No capital expenditures were forecasted for 2024 in this subprogram. In comparison, the Company spent $2.3 million in 2023. WP-MPG-8 provides a list of projects with the related cost.[72] In response to discovery, the Company provided additional details, including the number of units installed in prior years and planned for future years, as well as the current phase of development as of early April 2025 for projects in $1 million or greater in size.

In the discovery response, the Company states that the 2025 planned projects were currently in the design and procurement phase. However, the seven projects planned for 2026 of $1 million or greater size are still in the planning and scoping phase.[73] These projects are still in the early planning stage of development with no engineering/design yet started or completed. It is premature to include the seven projects in rate base given that

[72] Exhibit AG-21 includes WP-MPG-8
[73] Id. includes DR AG-CE-0336.

they are still being evaluated whether they should be pursued, and the forecasted costs are preliminary without any design work completed. Customers should not be charged for costs that may not occur during the projected periods. The following table shows the seven projects retrieved from WP-MGP-8.

| Project ID | RCV Project Description | 2026 Projection | 12 Months Ending 10/30/2026 Projection |
|---|---|---|---|
| GL-02825 | FDM-1200B Moscow VS Vlv 1252B Repl | $ 1,084,230 | $ 1,073,387 |
| GL-02943 | FDM-2800 FDM,Milr,Hdsn,Sutn RCV Inst | 3,252,688 | 3,220,161 |
| GL-03049 | SAG-250 MtPl to Zilwke RCV Inst | 2,168,459 | 2,146,775 |
| B-GL-00120 | TEDI-Three Rivers Landfill | 1,337,191 | 1,323,819 |
| B-GL-00129 | TEDI-North Bradley VS (Coleman-Beavert | 2,840,682 | 2,812,275 |
| B-GL-00140 | TEDI-Blanchard Rd VS | 1,951,613 | 1,932,097 |
| B-GL-00214 | Babcock VS | 1,653,450 | 1,636,916 |
| **TOTAL EXPENDITURE** | | **$ 14,288,314** | **$ 14,145,430** |

Therefore, I recommend that the Commission disallow $14,145,000 for the projected test year from the Company's forecasted capital expenditures.

## C. Gas Compression & Storage - Capital Expenditures

On page 1 of Exhibit A-12 (TKJ-5), Schedule B-5.7, the Company forecasted capital expenditures for Gas Compression and Storage projects of $175.3 million for 2024, $184.1 million for the 10 months ending October 2025, and $162.0 million for the 12 months ending October 2026. In comparison, the Company spent $113.0 million in 2023. Included in these amounts are capital expenditures for projects where I will recommend certain adjustments as discussed in my testimony below.

**1. Lyon 29/34 (Northville Storage) Dehydration**

**Q. PLEASE DISCUSS THE NORTHVILLE STORAGE GAS DEHYDRATION PROJECT.**

A. On line 10 of page 2 of Exhibit A-12 (TKJ-5), Schedule B-5.7, the Company shows the forecasted capital expenditures for the Northville Storage Field at $8.5 million for 2024, $25.4 million for the 10 months ending October 2025, and $4.7 million for the 12 months ending October 2026. Beginning on page 33 of his direct testimony, Mr. Timothy Joyce discusses the Lyon 29/34 project which entails the construction of a dehydration system. The Company seems concerned with the moisture content of the gas withdrawn from the Northville gas storage field not meeting the 7bl. per Mcf required for delivery to customers, as measure at the customer's meter. The Lyon 29/34 is a metering station feeding gas to a transmission line and the Northville storage compressor station. To resolve the occasional excessive moisture content of the gas stream, originating from the Northville storage field during the gas withdrawal period, the Company wants to install a gas purification/dehydration facility near the Northville compressor station.

Mr. Joyce does not identify the cost of this project in his testimony. In response to discovery, the Company provided a schedule that shows the total cost from 2022 to the end of 2026 at $37.4 million.[74] ~~However, WP TJK-6 shows larger capital expenditures from 2024 to 2026, that when added to the amounts spent in 2022 and 2023 bring the total cost of the project to nearly $41 million.~~ The Company spent $1,149,000 in 2022,

[74] Exhibit AG-22 includes DR AG-CE-0506 with ATT_1.



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$1,191,000 in 2023, $6,122,000 in 2024, and forecasted ~~$8,453,000~~$8,028,000 for 2024, ~~$25,351,000~~$25,249,000 for the 10 months ending October 2025, and ~~$4,672,000~~$3,649,000 for the projected test year.[75] These amounts totaling to ~~$40,816,000~~$39,266,000 are included in this rate case.[76]

In Attachment 2 to DR AG-GE-0506, the Company also mentions that it has filed an Act 9 application to build a pipeline to connect the dehydration facility to the transmission line. There is no disclosure or discussion about this pipeline in Mr. Joyce's direct testimony. In fact, for a $~~41~~ 37.4 million project there is inadequate testimony to support and justify the project.[77]

**Q. WHAT IS YOUR ASSESSMENT OF THE NORTHVILLE STORAGE GAS DEHYDRATION PROJECT?**

A. The Company seems to have started work on certain portions of the project. However, the cost of the project is significantly large at $~~41~~ 37.4 million and given the infrequent occurrence of moisture issues with the gas stream from the Northville storage fields, further work on the project should be avoided. In the last two rate cases, I filed testimony proposing that the project should be analyzed further for a more cost-effective solution. Due to the fact that the last two gas rate cases for the Company have been settled, the

[75] Exhibit A-22 DR AG-CE-0506 ATT_1 and WP-TJK-6 for Northville.
[76] The forecasted 2024 capital expenditures were included in the Company's filed rate instead of the actual 2024 capital expenditures.
[77] The $37.4 million represents the project costs estimated by the Company through the end of 2026 with actual capital expenditures for 2024. The forecasted amount included in rate base by the Company through the 2026 projected test year is $39,266,000 which includes forecasted capital expenditures for 2024.

Commission has not had an opportunity to rule on the reasonableness and prudency of this project.

In response to discovery in the last two rate cases, the Company reported that it had identified only a few incidents of excessive moisture in the gas stream between 2019 and 2021. In this rate case, the Attorney General asked the Company to update that information. The updated information shows similar results with one well showing unusual results due to a recent re-drilling of the well and injection of fluids in the well during the redrilling process.[78] No moisture readings have been taken since March 2021. Beginning in 2021, the Company changed the utilization of the Northville storage fields to be a peaking storage facility to be used only during days in the winter when customer gas demand reaches near peak demand.[79] Therefore, like in 2021, in future years no gas withdrawals from the fields may happen on a regular basis and may only occur on very few select days. In fact, the Company withdrew gas from the field only once in 2021 in March and perhaps once in 2022, and none in 2023 and 2024. It does not seem cost effective to build a high-cost facility that will sit idle and not be utilized other than on rare occasions.

Attachment 4 to DR AG-CE-0506 shows that the volume of gas withdrawn on those unusual occasions in 2021 and 2022 represented less than 0.01% to 0.04% of the Company's total system sendout on those days. These are infinitesimal percentage that

[78] Exhibit A-22 includes DR AG-CE-0506 ATT 3 and ATT_4, and DR AG-CE-0820.
[79] Case No. U-20541, Jonathon Guscinski direct confidential testimony at page 71.



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should not pose a problem when the Company mixes the small amount of gas withdrawn from the Northville field with the other gas supply flowing through the transmission lines and ultimately delivered to customers. The end result is that natural gas delivered to customers will be at moisture content well below the 7 lb. per Mcf standard measure at the customer meter.

In discovery request AG-CE-0316 in Case No. U-21490 and again in this rate case, the Attorney General asked the Company whether it had performed an analysis to see if gas withdrawn occasionally from the Northville storage fields with higher moisture content could be blended with drier gas from other sources as an effective solution to prevent a moisture problem before delivering the gas to customers. In response, the Company stated that it had not performed such an analysis because it does not recognize gas blending as a competent means for ensuring gas quality.[80] Although such a position makes sense on a wider scale, on the rare occasions of gas withdrawals from the Northville storage fields and in limited volumes, it can be an effective strategy. DTE Gas utilizes gas blending temporarily when it experiences failures with its gas dehydrating equipment at or near its gas storage fields with no ill effect on customers' gas burning equipment.

The Company also raises concerns about pipe corrosion with moisture in the gas flow. However, all gas has a certain amount of moisture and the small about of gas with the higher level of moisture of less than 15 lb. per Mcf withdrawn from the Northville field

[80] Exhibit AG-22 includes DR AG-0819.



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instead of the typical 5 lb. or less per Mcf in the remaining gas flow from other sources will not cause any measurable incremental corrosion in the Company's pipeline system.

**Q. WHAT IS YOUR CONCLUSION AND RECOMMENDATION?**

A. The Lyon 29/34 Northville Gas Dehydration project is not a cost-effective solution for an investment exceeding $~~41~~ 37.4 million on a project for a facility that would be rarely used.

Therefore, I recommend that the Commission remove the capital expenditure of $1,149,000 for 2022, $1,191,000 for 2023, ~~$8,453,000~~$8,028,000 for 2024, ~~$25,351,000~~$25,249,000 for the 10 months ending October 2025, and ~~$4,672,000~~$3,649,000 for the projected test year from this rate case.

**2. Storage New Wells**

**Q. PLEASE IDENTIFY THE CAPITAL EXPENDITURES PROPOSED BY THE COMPANY FOR DRILLING NEW STORAGE WELLS.**

A. On page 2, line 14, of Exhibit A-12 (TKJ-5), Schedule B-5.7, the Company forecasted capital expenditures to drill new storage wells of $17.2 million for 2024, $28.0 million for the 10 months ending October 2025, and $32.3 million for the projected test year. In comparison, the Company spent $11.4 million in 2023. Mr. Joyce discusses the capital expenditures for this program beginning on page 35 of his direct testimony.

In response to discovery, the Company provided an updated Table 7 from Mr. Joyce's testimony with actual expenditures incurred for each well for the applicable year from

2019 to 2026.[81] Regarding new wells, and excluding re-entry wells, the data shows that the average cost to drill a new well in 2023 and 2024 on average was $6,843,000. Adjusted for inflation the cost for 2025 is $7,007,000 and for 2026 is $7,182,000.

For 2025, the Company plans to drill 4 new wells for a total amount of $36,352,000 and at an average cost per well of $9,088,000. This cost is 30% higher than the 2025 average cost per well of $7,007,000 from 2024 adjusted for inflation. The Company's forecasted cost per well is excessive and not justified. Using the inflation adjusted cost $7,007,000 and applying it to the 4 planned wells, the total forecasted cost is $28,028,000 for 2025 and $23,357,000 for the 10 months ending October 2025. This amount is $4,647,000 lower than the $28,004,000 forecasted by the Company.

For 2026, the Company plans to drill 4 new wells for a total amount of $31,762,000 at average cost per well of $7,941,000. This cost is 11% higher than the 2024 average cost per well adjusted for inflation of $7,182,000. The Company's forecasted cost per well is excessive and not justified. Using the inflation adjusted cost of $7,182,000 and applying it to the 4 planned wells, the total forecasted cost is $28,728000 for 2026. This amount is $3,034,000 lower that the Company's forecasted cost of $31,762,000. The $3,034,000 prorated for the 10 months in the projected test year plus two months from the 2025 lower cost results in the projected test year adjustment of $3,916,000.[82]

[81] Exhibit AG-23 includes DR AG-CE-0508.
[82] 2025: 36,352,000 - $28,028,000 = $8,324,000 x 2/12 = $1,387,000 + 2026: $3,034,000 x 10/12 = $3,916,000.

Therefore, I recommend that the Commission remove $4,647,000 for the 10 months ending October 2025 and $3,916,000 for the projected test year from the Company's forecasted capital expenditures.

**3. Hessen Storage Pipeline**

**Q. PLEASE DISCUSS YOUR FINDINGS REGARDING THE HESSEN STORAGE FIELD PIPELINE AND THE RELATED CAPITAL EXPENDITURES PROPOSED BY THE COMPANY.**

A. In Table 8 on page 41 of his direct testimony, Mr. Joyce identified the Hessen field pipeline as a project that requires Act 9 approval. The Company forecasted capital expenditures of $15,703,000 for 2025 with $13,450,000 for the 10 months ending October 2025 and $2,003,000 for the projected test year.[83] In discovery, the Company disclosed that the Act 9 filing requesting Commission approval was filed on December 18, 2024.[84]

The Company has not yet received approval to build this pipeline and related laterals. Depending on when it receives approval, it is also uncertain when construction of the pipeline and lateral will occur and what amount will be spent and when. Therefore, it is premature to include the forecasted capital expenditures in rate base in this rate. I recommend that the Commission remove the $13,450,000 for the 10 months ending

[83] WP-TKJ-6.
[84] Exhibit AG-24 includes DR AG-CE-0509 with ATT_1.

October 2025 and $2,003,000 for the projected test year from the Company's forecasted capital expenditures in this rate case.

**4. Gas Compression Projects**

**Q. PLEASE DISCUSS YOUR FINDINGS REGARDING THE GAS COMPRESSION PROJECTS AND THE RELATED CAPITAL EXPENDITURES PROPOSED BY THE COMPANY.**

A. On line 2 of Exhibit A-12 (TKJ-5), Schedule B-5.7, the Company shows forecasted capital expenditures for Compression projects of $62.3 million for 2024, $44.6 million for the 10 months ending October 2025 and $66.2 million for the projected test year. Mr. Joyce discusses certain aspects of the compression capital projects beginning on page 26 of his direct testimony.

In discovery, the Attorney General asked the Company to identify the current phase of development that each project in size of $1 million or greater. The Company identified projects in various phases of development from Engineering Design to Construction and Completed. In response to a subsequent discovery request, the Company provided the timeframe that Engineering Design entails for those projects so designated. The information shows that some projects have engineering design that spans three to four years, which is very unusual for the relatively moderate size of the projects being undertaken. Thirteen of the projects have engineering design completion dates of

September 2026 or later.[85] Clearly, these projects are not likely to be in significant construction mode during 2026 or be completed by the end of projected test year ending October 2026.

The thirteen projects have forecasted capital expenditures of $786,000 for the 10 months ending October 2025 and $29,295,000 for the projected test year. Those projects have been highlighted in a copy of WP-TKJ-5 provided by the Company and included in Exhibit AG-25. Given the limited development of these projects and the uncertainty of the forecasted costs, they are premature for inclusion in this rate case. Therefore, I recommend that the Commission remove the $786,000 for the 10 months ending October 2025 and $29,295,000 for the projected test year from the Company's forecasted capital expenditures.

**5. Gas Compression & Storage – 2024 Capital Expenditures**

In discovery, the Attorney General asked the Company to provide the actual amount spent on all Gas Compression and Storage capital programs during 2024. In response the Company reported that it spent $167,776,000 in 2024.[86] In Exhibit A-12 (TKJ-5), Schedule B-5.7, page 1, the Company shows that it included $175,339,000 of capital expenditures for 2024 in this rate case. The difference is an underspent amount of $7,563,000. This amount should be removed from rate base in this rate case. The

[85] Exhibit AG-25 includes DR AG-CE-0827.
[86] Exhibit AG-26 includes DR AG-CE-0517.



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Company did not incur this cost and it is not fair or reasonable for the Company to earn a return and recover depreciation expense for costs in it did not incur.

Therefore, I recommend that the Commission remove the 2024 underspent amount of $7,563,000 from rate base in this rate case.

## D. Information Technology (IT) - Capital Expenditures

Information Technology projects are often presented by both the Company witness in the operating function that requires and sponsors the project and from the IT witness responsible to develop and implement the project, and who is also responsible for the cost of the project. Therefore, reference is often made to testimony, exhibits and discovery responses from multiple witnesses.

### 1. Gas Facilities Tracking and Traceability Project

**Q. PLEASE DISCUSS WHAT ADJUSTMENTS YOU PROPOSE TO THE CAPITAL EXPENDITURES FOR THE GAS FACILITIES TRACKING AND TRACEABILITY SYSTEM.**

A. On page 76 of his direct testimony, Mr. Warriner discusses the Tracking and Traceability system project with forecasted capital expenditures of $5,295,411 and $508,607 in O&M development costs in the test year. However, a report provided by Company witness Stacey Baker for ROM[87] adjusted IT capital expenditures shows that an additional $2,218,000 was included in the 10 months ending October 2025.[88] The project is intended

[87] ROM = Rough Order of Magnitude is an adjustment to compensate for forecasting errors in preliminary project cost estimates.
[88] Exhibit AG-27 includes DR AG-CE-0616 with ATT_1.



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to develop a system to identify, track, and trace the Company's gas facilities from pipes to fittings and other components.

This project was also proposed in Case No. U-21490. In discovery in that case, the Attorney General asked the Company to provide the project cost/benefit analysis and the project development phases including the current phase of the project. In response, the Company provided a copy of the project cost analysis showing that the estimated cost of the project was in excess of $15 million to be developed over the 2025 to 2027 timeframe. No cost savings or financial benefits were identified for the project. The Company also disclosed that the project last year was in the investment planning phase.[89]

This rate case, the Company reported in response to discovery that the project is in the Origination phase, which seems to be equivalent or close to the same stage of development that it was in last year.[90] Page 138 of Exhibit A-21 (SHB-6) shows an update project cost of $17 million, including O&M development costs. No cost savings or financial benefits have been identified in the financial analysis and the Benefit/Cost ratio is a negative 1.0, meaning the project entails only costs and no financial benefits.

**Q. WHAT IS YOUR ASSESSMENT OF THE TRACKING AND TRACEABILITY PROJECT?**

A. Aside from the fact the project is not economically justified, the project is in the early stage of development being in the Origination phase. It appears that only high-level

[89] U-21490 Exhibit AG-31 includes DR AG-CE-0221 with related attachments.
[90] Exhibit AG-27 includes DR AG-CE-0370.

requirements have been identified and not much work has been done to assess and match detailed system requirements to the prospective system to be acquired or developed. Given the preliminary stage of development and the lack of an economic case for the project, I recommend that the Commission remove the capital expenditures of $2,218,000 for the 10 months ending October 2025 and $5,295,000 from the projected test year, along with $509,000 from O&M expense.

## 2. SAP-ERP Project (SAP S/4HANA)

**Q. PLEASE BRIEFLY DISCUSS THE NEW SAP-ERP SYSTEM DEVELOPMENT PROJECT PROPOSED BY THE COMPANY AND THE RELATED CAPITAL EXPENDITURES.**

A. Beginning on page 104 of her direct testimony, Ms. Baker discusses the implementation of a new Enterprise Resource Planning (ERP) system with SAP Software Company (SAP). The Company also refers to this system as the SAP S4/HANA development project. The Company identified the total cost of the project at [Begin Conf] [redacted]

[91] Exhibit AG-28 CONF includes DR AG-CE-0610 ATT_1 CONF.

[redacted] [End Conf].

In her direct testimony, Ms. Baker states that the current ERP system with SAP needs to be modernized because it will reach the end of mainstream vendor maintenance on December 31, 2027. Although the system would be modernized with a new software system, it will basically replace the same functions of the current ERP system of billing, materials purchasing, warehousing, finance, accounting, payroll, customer relationship management, and other technical functions.[92] In response to discovery, the Company stated that the current SAP-ERP system functions well and it is being replaced because of the end of system support by SAP.[93] This is clearly a case of forced obsolescence by the vendor in order to sell new software, services, and technology.

On page 108 of her direct testimony, Ms. Baker states that the Company will extend the current system support and maintenance service with SAP past the December 2027 date and into 2028, noting that the extended support is only available until 2030. In discovery, the Attorney General asked the Company whether it had asked SAP to extend the service and support agreement through and potentially past 2030. In response, the Company stated that it had not done so and pointed out that it would need to purchase extended support,[94] which in a subsequent discovery response the Company identified at [Begin Conf] [redacted] [End Conf].[95] This fee for system support is logical and is likely similar to

[92] Id. includes DR AG-CE-0622 with ATT_1 CONF and AG-CE-0850 CONF.
[93] Exhibit AG-29 includes DR AG-CE-0624.
[94] Id.
[95] Exhibit AG-28 CONF includes DR AG-CE-0851.

what the Company currently pays for system support and software releases and upgrades. Operating the current system past 2030 is a viable solution given that the system is still functioning well and is meeting all the operating requirements of the Company.

Furthermore, the Company has not identified any cost savings or financial benefits for implementation of a new ERP system. The project financial analysis on page 121 of Exhibit A-21 Confidential show the project costs but no financial benefits and a negative Cost/Benefit ratio of negative 1.0, meaning the project is not financially justified.

**Q. DID THE COMPANY IDENTIFY THE CURRENT STATUS AND PHASE OF DEVELOPMENT OF THE NEW SAP-ERP PROJECT?**

A. Yes. In response to discovery, the Company stated that the project is currently in the Investment Planning phase and it is currently preparing a Request for Proposal (RFP) to be issued to different vendors in May 2025.[96] Although the Company seems to have a high preference to stay with SAP to simplify the conversion to the new system, it is not clear yet who the winning bidder will be and which system the Company will ultimately select to implement and at what cost.

**Q. WHAT IS YOUR CONCLUSION AND RECOMMENDATION REGARDING THE COMPANY PROPOSED IMPLEMENTATION OF A NEW ERP SYSTEM?**

A. From the discussion above, it is clear that the current ERP system still functions well and meets the operating needs of the Company. The option also exists for the Company to

[96] DR AG-CE-0622d (Exhibit AG-28 CONF) and DR AG-CE-0625 in Exhibit AG-29.

continue to operate the system into 2030 and potentially past that date with system support by SAP. The Company still has not selected a vendor for the new ERP system and will likely undertake the evaluation of the optimal system to purchase in the second half of 2025. From various aspects, it is premature to include any capital expenditures in this rate case and to defer large forecasted O&M costs in a regulatory asset without firm plans for project execution.

Therefore, I recommend that the Commission remove the [Begin Conf] [redacted] [End Conf].

**3. ARP-OT Support Gas**

**Q. PLEASE DISCUSS WHAT ADJUSTMENTS YOU PROPOSE TO THE COMPANY'S FORECASTED CAPITAL EXPENDITURES FOR THE PURCHASE OF SERVERS AND RELATED EQUIPMENT UNDER THE ARP-OT GAS SUPPORT PROGRAM.**

A. On pages 61 and 62 of her direct testimony, Ms. Baker discusses the purchase of computer servers and related equipment on a five-year cycle, as this equipment ages and becomes obsolete. On page 7 of Exhibit A-22, the Company shows the actual capital expenditures of $245,000 for 2023 and forecasted amounts of $1,033,000 for 2024, $979,000 for 2025, $816,000 for the 10 months ending October 2025, $2,766,000 for 2026, and $2,488,000 for the projected test year.

In response to discovery, the Company provided actual capital expenditures for 2022 and 2024.[97] The information provided by the Company both in its filed exhibit and in response to discovery shows considerable variability in capital spending for a program that functions on a routine five-year replacement cycle. Most concerning is the large increase in capital expenditures in 2026 and the projected test year. The average capital spending over the historical three years from 2022 to 2024 was $496,000. For the 10 months ending October 2025, the Company proposes to nearly double that amount to $816,000 and for the projected test year increase it five-fold to $2,468,000.

Given the historical variability in spending on the program, I propose that the capital expenditures for the forecasted periods be set at the three-year historical level plus an adjustment for forecasted inflation. For 2025, the inflation adjusted amount is $508,000 or $423,000 for the 10 months ending October 2025. This amount is $393,000 lower than the $816,000 forecasted by the Company.

For 2026, the inflation adjusted capital expenditures are $521,000 with $519,000 applicable to the projected test year.[98] The $519,000 is $1,949,000 lower than the Company's forecast of $2,468,000 for the projected test year.

To set the capital expenditures for this program at a reasonable level, I recommend that the Commission approve the forecasted capital expenditures I calculated and remove the

[97] Exhibit AG-30 includes DR AG-CE-0638 with attachment.
[98] Two months from 2025 and 10 months from 2026.



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excess amount of $393,000 for the 10 months ending October 2025 and $1,949,000 for the projected test year from the Company's forecasted capital expenditures.

**4. ARP-Physical Security**

**Q. PLEASE DISCUSS WHAT ADJUSTMENTS YOU PROPOSE TO THE COMPANY'S FORECASTED CAPITAL EXPENDITURES FOR THE ARP-PHYSICAL SECURITY PROJECT.**

A. On pages 62 and 63 of her direct testimony, Ms. Baker discusses upgrading the Company physical security system by installing advanced door systems at its various buildings, installing additional and upgraded security cameras, and various other equipment. The proposed capital expenditures for the projected test year are $747,000. Ms. Baker's testimony does not identify significant problems with the current security equipment and doors other than a desire to refresh the equipment.

In discovery the Attorney General asked the Company to identify major problems experienced in the past three years and why advanced door systems were necessary. The Company was also asked to confirm that it already has security cameras, gate and lock systems, and other security equipment in place. In response to discovery, the Company stated that some cameras are no longer working, they require cleaning and is experiencing failures in some of the equipment. This information indicates routine problems that require repair or replacement of certain items, as they fail, and not a wholesale investment in new equipment and technology.[99]

[99] Id. includes DR AG-0616 and 0849.

From the information gathered from the Company, my conclusion is that this is not a priority project and should not be undertaken at this time given other more pressing priorities for gas infrastructure upgrades. Therefore, I recommend that the Commission remove the $747,000 from the Company's forecast capital expenditures for the projected test year.

**5. Forward Web Proxy Services**

**Q. PLEASE DISCUSS WHAT ADJUSTMENTS YOU PROPOSE TO THE COMPANY'S FORECASTED CAPITAL EXPENDITURES FOR THE FORWARD WEB PROXY SERVICES PROJECT.**

A. On pages 115 and 116 of her direct testimony, Ms. Baker discusses undertaking this IT system project to replace a system currently in place with a third-party vendor. The Forward Web Proxy Services system works as a filtering process to direct customer internet inquiry traffic to different subsystems in the Company's web server. According to Ms. Baker's direct testimony the Company has experienced technical glitches with the vendor service and now wishes to develop its own software at a cost of $4.5 million with $1.2 million assigned to the gas business for the projected test year. The Company has adjusted this amount down to $939,000 after the ROM adjustment for inclusion in this rate case.

In discovery, the Attorney General asked the Company to identify the total cost of the project for both the gas and electric portions of the company, the frequency and number of problems experienced, the cost/benefit analysis to justify undertaking the project, and

whether the Company has worked with the current service provider to resolve the technical problems and improve the level of service provided. In response, the Company provided the number of incidents and impact days on Company operations for the three years 2022-2024. The information provided shows that the number of incidents declined significantly in 2024 from prior years with few incidents and impacts on non-critical functions and no incidents and impact on Company operations.[100]

The Company also reported that it has been working with the vendor and acknowledged service improvement overall in the past year with still some lingering issues. The Company's financial analysis for the new proposed project shows a cost/benefit ratio of negative 1.0, meaning that no financial benefits have been identified to undertake this project.

My conclusion from the information provided by the Company is that the new software development project is not necessary at this time and not a priority project that should be undertaken for the projected test year. Therefore, I recommend that the Commission remove the $939,000 from the forecasted capital expenditures for the projected test year along with the $180,000 of O&M expense.

**6. OT Data Center Migration and Access Management Projects**

**Q. PLEASE DISCUSS WHAT ADJUSTMENTS YOU PROPOSE TO THE COMPANY'S FORECASTED CAPITAL EXPENDITURES FOR THE OT DATA**

[100] Exhibit AG-31 includes DR AG-CE-0630.

**CENTER MIGRATION AND PHYSICAL ACCESS MANAGEMENT AND ALARM RESPONSE PROJECTS.**

A. On pages 100 and 101 of her direct testimony, Ms. Baker discusses the relocation of the servers and systems, which monitor some of the Company's electric and gas operations, from the current location at the Parnel building to another location. Apparently, the Company has experienced some problems with climate and water infiltration into the building and feels that the situation is unrepairable and untenable. The cost of the relocation and associated equipment upgrades is $11 million between capital expenditures and O&M development costs, of which $3.6 million would be assigned to the gas business. The amount of capital expenditures included in this rate case is $1,441,000 after the ROM adjustment with $716,000 of O&M development costs for the projected test year.

In response to discovery, the Company elaborated about the water infiltration risk and the aging climate equipment. From the information provided, it is not clear why these problems cannot be fixed at a lower cost than $11 million and the current location made safe and workable. In the discovery response, the Company also stated that the project is currently in the investment planning phase, which indicates that it is in the early stage of development.[101]

Regarding the Physical Access Management and Alarm Response project, Ms. Baker discusses the replacement of the current physical access management system that manages user identity, authentication, access to facilities, and reports on user activities. The

[101] Id. includes DR AG-CE-0621.



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Company finds the current system out of date, with inconsistent behavior, and some glitches in its operation, which allegedly create work inefficiencies.

In discovery the Attorney General asked the Company to provide the total company cost of the project, identify some of the major problems currently experienced, explain why the problems with the current system cannot be fixed at a lower cost, and provide a copy of the cost/benefit analysis showing that the cost savings from removing work inefficiencies and other financial benefits justify undertaking the project.

In response to discovery, the Company reported that the total cost of the project, including both capital expenditures and O&M development costs, would be approximately $7.0 million of which $2.2 million would be assigned to the gas business. For the projected test year in this rate case, the Company has included $678,000 of capital expenditures after the ROM adjustment and $102,000 of O&M expense.[102]

The Company also identified a dozen or so technical glitches during 2024 which were resolved in minutes or generally within 24 hours. The Company also reported that it has worked with the vendor of the current system to resolve issues and made a system upgrade in 2024. Regarding the new proposed system, the Company stated that it has not yet chosen a specific vendor and will be conducting an RFP at some later date.[103] The financial analysis prepared by the Company shows no cost savings or financial benefits

[102] Id. includes DR AG-CE-0631 with ATT_1.
[103] Id. includes DR SA-CE-004.



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from the implementation the new system despite claims of cost savings from reduced equipment purchases and waste reductions.

**Q. WHAT ARE YOUR CONCLUSIONS AND RECOMMENDATIONS FOR THE TWO PROPOSED PROJECTS DISCUSSED ABOVE?**

A. The Company has not present sufficient information that it has performed a robust analysis to continue to use the existing assets with appropriate changes and upgrades that will avoid a combined $18 million of capital expenditures and O&M development costs for the two projects. Furthermore, the two projects are still in the initial phase of development with no specific systems or vendors evaluated. The two projects are still premature and the costs still preliminary and uncertain to include in rate base and O&M expense in this rate case.

Therefore, I recommend that the Commission remove $2,119,000 of capital expenditures and $818,000 of O&M expense for the two projects from this rate case.

**7. IT Projects – 2024 Capital Expenditures**

In discovery the Attorney General asked the Company to provide the actual amount spent on all IT capital programs during 2024. In response the Company reported that it spent $26,378,000 in 2024.[104] In Exhibit A-12 (SHB-4), Schedule B-5.1, page 1, the Company shows that it included $32,046,000 of capital expenditures for 2024 in this rate case. The difference is an underspent amount of $5,668,000. This amount should be removed from rate base in this rate case. The Company did not incur this cost and it is not fair or

[104] Exhibit AG-32 includes DR AG-CE-0637 with attachment.

reasonable for the Company to earn a return and recover depreciation expense for costs in it did not incur.

Therefore, I recommend that the Commission remove the 2024 underspent amount of $5,668,000 from rate base in this rate case.

## E. Transportation Fleet & Equipment Capex

**Q. PLEASE DISCUSS WHAT ADJUSTMENTS YOU PROPOSE TO THE COMPANY'S FORECASTED CAPITAL EXPENDITURES FOR THE TRANSPORTATION FLEET AND EQUIPMENT.**

A. On page 1 of Exhibit A-12 (CEB-1) the Company shows forecasted capital expenditures for Fleet Vehicle purchases, including electric vehicle purchases, of $9.7 million for 2024, $6.8 million for the 10 months ending October 2025, and $13.3 million for the projected test year. On page 1 of Exhibit A-28 (CEB-3), the Company provided further details of purchases by vehicle type with quantities and related dollars from 2023 to 2026 and the projected test year.

In discovery, the Attorney General asked the Company to expand Exhibit A-28 to include actual data for 2022 and 2024, explain the reasons for higher purchases of certain vehicle types in 2026, and correct certain missing information. Based on the additional information provided by the Company, I calculated an average purchased cost per vehicle of $76,892 based on the actual number of vehicles purchased in 2024. The average cost per vehicle purchased in 2023 and 2022 was lower at $66,406 and $61,293, respectively. In comparison, the Company's forecasted costs per vehicle for 2025 and the 2026

projected test year are $118,128 and $126,505, respectively. The forecasted increase over the 2024 actual cost per vehicle is 54% for 2025 and 65% for 2026 purchases.[105]

The forecasted cost increases are excessive and unsupported. To develop a reasonable forecast for 2025 and 2026, I used the 2024 average cost per vehicle of $76,892 and applied the inflation factors of 2.4% and 2.5%. Based on these factors, I calculated an average vehicle cost of $78,737 for 2025, which multiplied by the 86 vehicles forecasted to be purchased for the year results in forecasted capital expenditures of $6,771,000 or $5,643,000 for the 10 months ending October 2025. This amount is $1,202,000 lower than the $6,845,000 forecasted by the Company

For the projected test year, I calculated an inflation adjusted cost per vehicle of $80,705, which multiplied by the 105 vehicles planned to be purchased for the period results in forecasted capital expenditures of $8,474,000. This amount is $4,809,000 lower than the Company's forecasted amount of $13,283,000.

To moderate the Company's excessive forecasted cost increases and capital expenditures, I recommend that the Commission remove $1,202,000 for the 10 months ending October 2025 and $4,809,000 for the projected test year.

[105] Exhibit AG-33 includes DR AG—CE-0648 with attachment.



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## F. Capital Expenditures - Summary

**Q. WHAT IS YOUR OVERALL RECOMMENDATION REGARDING THE LEVEL OF CAPITAL EXPENDITURES?**

A. The chart below summarizes my proposed reductions in capital expenditures in those areas where the level of capital expenditures presented by the Company is excessive and unnecessary.

**Summary of AG Disallowed Capital Expenditures**
Revised

| | Amount (millions) |
|---|---|
| Distribution Plant | $ 322.5 |
| Transmission Plant | 67.7 |
| Gas Storage & Compression | 100.9 |
| Information Technology | 35.8 |
| Transportation Fleet | 6.0 |
| Total | **$ 533.0** |

Based on my analysis and the information presented in my testimony above, I recommend that the Commission reduce the Company's proposed capital expenditures by $~~563.0~~533.0 million and reduce average rate base by ~~$535.1~~$514.7 million, including an adjustment to working capital of $154 million, as shown in Exhibit AG-34. The resulting effect of the lower rate base from the reduction in capital expenditures is a reduction in the revenue deficiency of $~~42.7~~41.1 million.

## V. Depreciation Expense

**Q. PLEASE DISCUSS THE DEPRECIATION EXPENSE ADJUSTMENT THAT YOU PROPOSE.**

A. In Exhibit AG-34 CONF Revised, I identified the adjustments to be made to the Company's proposed capital expenditures. Those reductions lower the amount of depreciation expense that the Company will incur during the projected test year. On the same exhibit, I have calculated the reduction in depreciation expense of ~~$13.7~~ $13.3 million. I recommend that the Commission reduce the Company's depreciation expense by this amount for the projected test year.

## VI. Property Tax Expense

**Q. PLEASE DISCUSS THE PROPERTY TAX EXPENSE ADJUSTMENT THAT YOU PROPOSE.**

A. In Exhibit AG-34 CONF Revised, I identified the adjustments to be made to the Company's proposed capital expenditures. Those reductions lower the amount of property tax expense that the Company will incur during the projected test year. On the same exhibit, I have calculated the reduction in property tax expense of ~~$3.9~~ $3.7 million. I recommend that the Commission reduce the Company's property tax expense by this amount for the projected test year.

## VII. Working Capital

**Q. THE COMPANY PROPOSED $1.468 BILLION OF WORKING CAPITAL IN THIS CASE.[106] DO YOU AGREE WITH THIS LEVEL OF WORKING CAPITAL?**

A. No. I recommend five changes in the working capital level, which total $154.0 million. These changes reduce the amount of Working Capital to $1.314 Billion. The first change reduces the Company's cash balance by $16.1 million. The second change corrects an error in deferred cloud computing costs for the SAP S/4 Hana project. The third item pertains to a correction of other cloud computing deferred and amortized cost for the projected test year. The adjustment to working capital for this item is approximately $1.0 million. The fourth change removes $7.4 million of deferred costs for the estimated loss from the planned sale of the Riverside Storage field assets. The fifth change corrects an error in the calculation of accrued taxes for a reduction in working capital of $127.8 million. These changes are summarized on Exhibit AG-35.

**Q. PLEASE EXPLAIN YOUR PROPOSED INCREASE OF $16.1 MILLION TO THE COMPANY'S FORECASTED CASH BALANCE.**

A. As shown in Exhibit A-12 (HLR-34), Schedule B-4, the historical cash balance for 2023 was $8.7 million. The average cash balance for the 13 months ended June 2024 decreased to $7.3 million, as shown in column (d) of the exhibit. The Company proposes to increase this recent average cash balance by an additional $21.1 million to arrive at the projected

[106] See Exhibit A-12 (HLR-34), Schedule B4

test year cash balance of $28.4 million. According to page 39 of Mr. Bleckman's direct testimony, the Company bases its adjustment and level of cash on hand on an assumed ratio of 1% of cash on hand to revenues from an analysis it performed a few years ago for a group of utilities. However, there are several problems with this approach.

First, the Company's current revenues are $2.28 billion.[107] If we were to rely on the 1% ratio, the forecasted case on hand should be $22.8 million and not $28.4 million. Even using the Company's forecasted revenues of $2.53 billion would yield a lower cash balance. Of course, using the forecasted revenues would not be appropriate because the Company is not likely to receive the entire additional revenue of $248 million it seeks in this rate case.

Second, cash on hand is not used to pay for revenues. It is used to pay operating expenses, capital expenditures, and dividends to the parent company. Therefore, the ratio that the Company has calculated to revenues has no logical connection to the need to keep cash on hand. Third, utilities maintain different levels of cash on hand during different months of the year depending on their seasonal needs for cash to pay for gas purchases, fund gas inventories and pay for operating expenses and construction costs. The seasonality of cash requirements is particularly pronounced for gas utilities given the large variability in monthly gas sales, purchases and gas inventories.

[107] Exhibit A-16, Schedule F2, page 1.

Fourth, every utility has different short-term borrowing facilities and different practices as to how they use or do not use them and may retain more or less cash on hand depending on those circumstances. Therefore, using an average ratio of cash on hand to revenues at a specific point in time does not take into consideration the unique aspect of a particular utility. Fifth, the analysis that the Company performed to arrive at the 1% ratio was based on cash reported by the other utilities in the financial statements. Those cash balances include cash invested in short-term securities under generally accepted accounting practices (GAAP). The Commission does not allow those short-term cash investments with interest bearing securities in the calculation of cash on hand for inclusion in working capital. Therefore, the 1% is likely inflated and inapplicable for ratemaking in a Michigan rate case.

In his testimony in this rate case, Mr. Bleckman implies that in Case No. U-21389, the Commission reconfirmed the use of the 1% ratio. However, a more thorough review of the order shows that the Commission seemingly is not wedded to the Company's approach by stating:

> The Commission agrees that Consumers' 13-month average method is consistent with past approvals of methods to determine cash balances and is reasonable given the abnormal disruption in the company's typical cash balance. See, 4 Tr 627-628, 795-800. However, the Commission notes that while it finds that the circumstances described by Consumers in this case constitute an abnormal disruption, the Commission will continue to evaluate the facts and circumstances of each rate case to determine whether deviation from the historical period is appropriate.[108]

[108] Case No. U-21389, MPSC order dated March 1, 2024.



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In Case U-21585, I provided evidence that the Company has had a propensity in recent rate cases to forecast cash balances that are well above the actual cash that the Company ultimately keeps on hand, which inflates rate base and allows the Company to earn a return on non-existing cash holdings. Although in that rate case, the Commission decided to accept the Company's proposed cash balance, it made it clear that a different approach may be in order in future rate case by stating:

> Nevertheless, considering the company's actual cash balance amounts in recent years, as illuminated by the Attorney General, and the Commission's evaluation of the facts and circumstances surrounding this issue on a case-by-case basis, the Commission finds it appropriate for Consumers to provide further and a more specific explanation in its next electric rate case as to why the company's approach to determining its cash balance remains appropriate and should continue to be approved.[109]

In line with the Commission order, I propose in this rate case to use the average cash balance that the Company actually held over the past three years based on the 13-month average cash balances at the end of each year 2022, 2023, and 2024. This three-year approach provides a normalized average of the cash needs of the Company over the most recent three years and is specific to the Company and its needs for cash on hand. As shown in Exhibit AG-35, the three-year average of cash on hand held by the Company was $12.3 million, which is $16.1 million lower than the amount forecasted by the Company. The $12.3 million is further supported by the Company's analysis provided in response to discovery.[110]

[109] Case No. U-21585, MPSC order dated March 21, 2025 at page 213.
[110] Exhibit AG-36 includes DR AG-CE-0498.



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Therefore, I recommend that the Commission reject the Company's 1% ratio calculation approach and instead adopt my proposed cash balance of $12.3 million for the projected test year and remove $16.1 million from the Company's forecasted working capital and rate base in this rate case.

**Q. PLEASE EXPLAIN THE REDUCTION OF $1.7 MILLION TO DEFERRED COSTS FOR THE IT SAP S/4 HANA CLOUD IMPLEMENTATION PROJECT.**

A. As discussed in the Capital Expenditures section of my testimony, the Company is proposing to implement a new ERP system referenced as the SAP S/4 Hana system. As part of the implementation, the Company proposed to run the system as a cloud computing application. In this rate case, the Company forecasted that it would incur cloud computing costs beginning in November 2025 through October 2026 accumulating to [Begin Conf] [redacted] [End Conf] as of the end of October 2026, which it proposes to defer to a regulatory asset account for later amortization to expense. In Exhibit A-26 (SHB-11) Confidential, the Company shows a calculated 13-month average balance of [Begin Conf] [redacted] [End Conf] in the deferred account for the projected test year. This amount is also shown in column (n) of Exhibit A-12, Schedule B4

In response to discovery requesting the basis for the calculation of the deferred balance, the Company reported that it had made an error in the calculation of the deferred balance by including the total company costs instead of only the gas business portion.[111] With the

[111] Exhibit AG-37 CONF includes DR AG-CE-0628, part (b), and Attachment 1 Confidential.

discovery response, the Company provided a revised schedule showing a corrected average deferred balance of [Begin Conf] [redacted] [End Conf] for the gas portion of its business. Accordingly, the Commission should remove the excess amount of [Begin Conf] [redacted] [End Conf] from the Company's proposed working capital balance.

**Q. PLEASE EXPLAIN THE OTHER ADJUSTMENT TO CLOUD COMPUTING DEFERRED COSTS AND AMORTIZATION EXPENSE THAT YOU HAVE IDENTIFIED.**

A. In column (g) of Exhibit A-12, Schedule B-4, the Company shows an increase of $2,724,000 in working capital for the projected test year pertaining to Prepaid Cloud Computing. The Company's workpaper WP-HLR-25 calculated this amount.[112] In recent years, the Company has moved more IT functions and processing to the "IT cloud" and has accumulated pre-paid fees paid to the suppliers of cloud services. In discovery, the Attorney General asked the Company to justify the increase in deferred costs and the underlying balances and amortizations to expense.

In response, the Company stated that some errors were made in compiling the deferred costs and the resulting amortization expense, which also affected the average deferred balance for the projected test year. The revised information provided by the Company shows that the average deferred balance for the projected test year declines by $1,034,000

[112] Exhibit AG-38 includes WP-HLR-25.



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from $7,320,000 to $6,286,000 after the correction. The amortization expense for the projected test year declines by $5,478,000 from $17,352,000 to $11,874,000.

Therefore, I recommend that the Commission reduce the projected working capital balance by $1,034,000 and remove $5,478,000 from the Company's forecasted amortization expense in this rate case.

**Q. PLEASE EXPLAIN WHY YOU ADVOCATE THE REMOVAL OF THE $7.4 MILLION OF DEFERRED COSTS FOR THE RIVERSIDE STORAGE FIELD ASSETS INCLUDED IN WORKING CAPITAL.**

A. In column (m) of Exhibit A-12, Schedule B4, the Company included $7,398,000 pertaining to the deferral and amortization of a loss from the expected sale of assets of the Riverside storage field. In response to discovery, the Company disclosed that subsequent to the filing of this rate case, the prospective buyer chose to terminate the preliminary agreement to purchase the assets. Although the Company is in discussions with another prospective buyer, the terms and timing of any potential agreement are currently unknown.[113]

Therefore, I recommend that the Commission remove the $7,398,000 from the Company's forecasted working capital for the projected test year.

**Q. PLEASE EXPLAIN YOUR CHANGE TO ACCRUED TAXES.**

[113] Exhibit AG-39 includes DR AG-CE-500, 0817, and WP-HLR-34

A. In column (k) of Exhibit A-12 (HLR-34), Schedule B-4, the Company reduces Accrued Taxes and increase working capital by $138.9 million to arrive at a $12.4 million balance in the projected test year. Ms. Rayl, who sponsors this exhibit, provided no explanation for this large change in her direct testimony.

In discovery, the Attorney General asked the Company to explain the large change in Accrued Taxes and provide the supporting calculations. In response, the Company reported that the calculation for Accrued Taxes in the project test year was incorrect and should have been higher by $127,805,000.[114]

Accordingly, I have adopted the Company's corrected balance of $140,204,000, which reduces working capital by $127,805,000. I recommend that the Commission approve this revision.

In summary, the changes discussed above result in a reduction of $154 million to working capital. I recommend that the Commission adopt this decrease in working capital for the projected test year.

## VIII. Capital Structure and Cost of Capital

### CAPITAL STRUCTURE

**Q. WHAT IS THE CAPITAL STRUCTURE YOU RECOMMEND FOR USE IN THE OVERALL RATE OF RETURN CALCULATION?**

[114] Exhibit AG-40 includes DR AG-CE-499.

A. I recommend that the capital structure shown on page 1 of Exhibit AG-41 be used in this case. The first three lines show the projected long-term debt, preferred equity and common equity capital of the Company, which represents the permanent capital structure for the test period ending October 2026. The capital balances in this exhibit reflect the amounts shown in Company Exhibit A-14 (MRB-1), Schedule D1, with an adjustment to rebalance the capital structure. The long-term debt component in Exhibit AG-41 has been increased by ~~$150~~ $194 million and the common equity component has been reduced by the same amount. The result is a capital structure with 50% of common equity and 50% of debt and preferred stock.

Q. **WHY DID YOU INCREASE LONG TERM DEBT BY ~~$150~~$194 MILLION AND OFFSET THIS CHANGE WITH LOWER COMMON EQUITY OF ~~$150~~$194 MILLION?**

A. The Company has proposed a permanent capital structure with a common equity component of 50.75%. This level of common equity exceeds the 50% equity ratio approved by the Commission in the Company's last two fully contested rate cases, Case Nos. U-21585 and U-21389.[115] The capital structure in this rate case should similarly mirror the common equity ratio last approved on March 21, 2025 of 50%. As discussed in my testimony in Case No. U-21585, there are several factors that clearly support a 50% common equity level.

[115] Case No. U-21585 Commission order dated March 21, 2025 and Case No. U-21389 dated March 1, 2024. In Case No. U-23189, the Commission approved an equity ratio of 50.02%.

These factors include (1) the Commission's consistent directive in the Company's prior electric and gas rate cases, which stated that a 50/50 capital structure is desirable and appropriate to ensure reduced costs to customers and maintain the Company's strong financial position, unless the Company can demonstrate that a higher ratio is justified; (2) The Company's strong cash flow to debt coverage ratio and credit ratings; (3) the Company's common equity capital contributions by the parent company, albeit often funded with long term debt issued at the parent company level; (4) the favorable regulatory environment in Michigan supported by historical returns on common equity above industry averages and in the top tier of the Company's peer group; and (5) the fact that the common equity ratio of the peer group, used to assess the cost of common equity in this case, is approximately 47%.[116]

**Q. PLEASE EXPLAIN YOUR ASSESSMENT OF THE COMMISSION'S DIRECTIVE TO THE COMPANY TO REBALANCE ITS CAPITAL STRUCTURE TO EQUAL AMOUNTS OF DEBT AND EQUITY CAPITAL.**

A. The Commission in its order of February 17, 2017 in Case No. U-17990 stated:

> The Commission expects that Consumers will have arrived at, or will present a strategy to return to, a balanced structure within the five-year infrastructure plan time period. If Consumers is unable to do so, a more complete analysis should be included to explain why such a result is reasonable and prudent.

[116] Exhibit AG-46 shows that the equity ratio for each peer company and the peer group average ratio of 47.3%.

In subsequent litigated rate cases, the Commission continued to remind the Company of this directive as it led the Company slowly toward a more balanced capital structure.

**Q. WHAT POSITION DID THE COMMISSION TAKE IN THE COMPANY'S MOST RECENTLY CONTESTED RATE CASE ON THE CAPITAL STRUCTURE?**

A. In the recent March 21, 2025 order in Case No. U-21585, the Commission decided to set the common equity ratio at 50%, as recommended by the Administrative Law Judge (ALJ) and supported by the Attorney General and other parties. On page 129 of the order, the Commission stated the following:

> Given the above, the Commission adopts the thorough and well-reasoned findings and recommendations of the ALJ. The Commission finds that the balanced capital structure most appropriately balances the interests of the utility's investors and customers, consistent with the holdings in Bluefield and Hope. As such, the Commission adopts a balanced capital structure of 50% debt to 50% equity, utilizing the Attorney General's methodology. See, PFD, pp. 310-311.

In its testimony in this rate case, the Company has not provided any new evidence or persuasive arguments as to why the Commission should veer from its stated goal of a 50/50 debt/equity capital structure for the Company.

**Q. IN THE MOST RECENT MOODY'S CREDIT REPORT COVERING CONSUMERS ENERGY, WHAT ARE THE REPORTED CASH FLOW TO DEBT RATIO RESULTS?**

A The most recent Moody's report of May 2024 shows the Company's performance under the CFO Pre-W/C to Debt ratio at 19.1% for 2023, 20.0% for 2022, 22.6% for 2021, and 21.5% for 2020, all of which are above the 18% downgrade threshold level.[117]

**Q. WHAT DID S&P STATE IN ITS MOST RECENT CREDIT REPORT ABOUT CONSUMERS ENERGY'S CREDIT PROFILE?**

A. The S&P August 20, 2024 credit report on the Company states "Michigan's regulatory construct is above average compared to peers." The report also points to the stream-lined 10-month rate case process, as well as the power supply and natural gas cost rider adjustments, which help the Company to earn its authorized ROE. S&P also notes that the Company's senior secured debt is rated as "A" by S&P (the middle of the "A" category).[118]

Regarding the cash flow coverage ratio, page 3 of the S&P report under the section "Downside Scenario" states:

> We could lower our rating on CE if its stand-alone financial measures weaken such that its FFO to debt weakens to consistently below 15% or we lower our rating on parent, CMS Energy Corp.[119]

However, page 5 of the report shows that the coverage ratio was 17.6% for 2023. S&P also estimated this ratio in the range of 18.3% for 2025 and 2026. These coverage ratios are not indicative of any concerns about a possible debt rating downgrade and are well above the 15% threshold set by S&P. On page 3 of the report, S&P states that the

[117] Exhibit AG-51includes DR AG-CE-0444 with the Moody's credit report dated May 31, 2024 with ratio data shown.
[118] Exhibit AG-51 includes DR AG-CE-0444 and the S&P report dated August 20, 2024
[119]S&P's FFO to debt ratio is similar to the Moody's cash flow ratio "CFO Pre W/C referred to earlier.

Company's credit metrics were weak in 2023 largely due to weather-related issues which they characterize as "mild sales and convective [higher] storm activities." S&P clearly understood that the decline in the coverage ratio in 2023 was temporary and not reflective of any long-term decline trends.

In 2023, the Company reported net income of $865 million and a return on equity (ROE) of 8.25% versus its authorized ROE of 9.90%. The lower net income and cash flow temporarily reduced the coverage ratio. In 2024, the Company reported an increase of 16% in net income to over $1.0 billion, or an increase of $142 million over 2023. The Company's earned ROE also increased to 9.1%.[120] As discussed in more detail below, the increase in profitability nearer to the authorized ROE will boost the cash flow to debt coverage ratio.

**Q. ON PAGE 15 OF HIS TESTIMONY, MR. BLECKMAN SATES THAT "THE COMPANY'S FFO TO DEBT RATIO AS CALCULATED BY MOODY'S IS TRENDING DOWN…WELL BELOW THE LOW END OF MOODY'S EXPECTED RANGE…" DO YOU AGREE WITH THAT STATEMENT?**

A. No. Mr. Bleckman fails to explain the unusual and short-term issues faced by the Company in 2022 and 2023, and mischaracterizes the situation in an attempt to mislead the Commission. The cash flow to debt ratio declined somewhat in 2022 due to a temporary increase in natural gas prices in 2022, which required the Company make larger short-term

[120] Based on total Consumers Energy reported net income of $1.007 billion and average common equity of $11,078.5 billion in the 2024 Form 10K.

borrowings. In 2022, this ratio was negatively impacted by higher gas rates which increased the cost of gas purchases and gas inventories. This in turn caused the Company to take on more debt which in turn reduced net income and increased the debt denominator in the calculation of the coverage ratio.

Gas inventory levels increased from $462 million in December 2021 to $840 million in December 2022. This increase of $378 million in gas inventory required more temporary debt financing for the year. The temporary increase in debt receded in 2023 and 2024. Page 2 of Exhibit AG-49 shows that if we adjust for this temporary phenomenon the Moody's FFO to Debt ratio would have been 20.9% instead of the actual result of 20%.

Temporary events from year to year can have either a positive and negative effect on earnings, cash flow, short-term debt, and the cash flow to debt coverage ratio. However, rating agencies look past those temporary issues and focus on the long-term financial health of the Company.

**Q. DID YOU CALCULATE THE IMPACT ON THE MOODY'S CASH FLOW TO DEBT COVERAGE RATIO BASED ON A 50% EQUITY RATIO IN THE COMPANY'S CAPITAL STRUCTURE AND AN AUTHORIZED ROE OF 9.75%**

A. Yes. On page 1 of Exhibit AG-49, I calculated the Company's key cash flow to debt ratio for 2023 adjusted for the ROE and Common Equity ratio levels I advocate in this case. I start with Moody's actual results for 2023 and adjust them to reflect a 9.75% ROE and a

50% common equity ratio. I chose 2023 because this is the most recent information available from Moody's.

For my analysis of 2023 cash flow ratio results, I started with actual 2023 data on line 1 of Exhibit AG-49. Next, on line 2, I adjust the capitalization to reflect a balanced capital structure. This increases long-term debt and reduces common equity. On line 3, I adjusted the cash flow upward to reflect a 9.75% ROE (versus the 8.25% ROE actually achieved in 2023). The result of these adjustments is shown on line 4 with a cash flow to debt ratio of 20.1%. This ratio is well above the 18% downgrade threshold noted by Moody's in its most recent report.[121] I have not presented any ratio results for S&P since the ratio calculations are highly similar and the S&P downgrade threshold is lower at 15%.

I will point out that by starting with actual Moody's 2023 results, items such as leases and short-term debt are already reflected in the cash flow and debt elements, which determine the ratio. The Company often points to these as being "add-ons" which are not considered in the permanent capital on a ratemaking basis. However, these are two separate calculations for different purposes and should be confused with one another.

In summary, my analysis shows that the 9.75% ROE and 50% common equity ratio would result in the Company's cash flow ratios being well above the long-term threshold levels that would result in a credit downgrade.

[121] Moody's indicates this to be "18% on a sustained basis".

**Q. DO THE RATING AGENCIES' CURRENT BUSINESS AND CREDIT OUTLOOK FOR THE COMPANY SHOW ANY SIGNIFICANT CONCERNS?**

A. No. S&P in its August 2024 report provides the following outlook for the Company:

> The stable rating outlook on CE reflects our expectation that management will focus on its core utility operations and reach constructive regulatory outcomes to avoid increasing business risk. We expect CE will maintain stand-alone financial measures consistent with the middle of the range for its financial risk profile category, specifically FFO to debt of 17%-19%.[122]

Similarly, in its May 31, 2024 report, Moody's provides the following rating outlook:

> The stable outlook reflects our expectation that financial metrics will remain stable and that Consumers Energy will continue to benefit from a consistent and generally credit supportive regulatory environment. The stable outlook also incorporates our view that Consumers Energy will maintain prudent financial policies while managing through its robust investment cycle and that debt levels at the parent will not increase materially.[123]

Fitch Investor Service provided the following summary of the Company's credit profile in its April 16, 2024 report:

> Constructive Regulatory Environment: Fitch believes the regulatory environment in Michigan under the Michigan Public Service Commission (MPSC) remains mostly constructive from a credit perspective. The regulatory framework allows for full pass-through of fuel costs and purchased power, forward-looking test years and a timely 10-month review period for general rate case resolution. Furthermore, Consumers Energy's authorized ROE of 9.9% compares favorably with industry averages. Increasing storm activity in Michigan and resultant power outages have attracted regulatory focus on reliability. In March 2023, the MPSC tightened performance standards for utilities by way of enhanced outage credits, and updated reliability standards. An MPSC-led straw proposal for additional potential financial incentives and disincentives has also been underway since August 2023. In Fitch's view, the risk of performance-based penalties is manageable within Consumers Energy's current credit profile. Fitch also does not expect a material negative outcome in the pending audit ordered by MPSC in October 2022 to assess the compliance of Consumers

[122] Exhibit AG-51 includes DR AG-CE-0444 with related attachment.
[123] Id.



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Energy with storm outages and safety regulations during the 2021 storms in Michigan. The final audit report is expected in summer 2024.[124]

The credit reports provide a favorable outlook of the Company's credit profile contrary to Mr. Bleckman's bleak predictions.

**Q. ON PAGE 21 OF HIS DIRECT TESTIMONY, MR. BLECKMAN REFERS TO EXHIBIT A-107 (MRB-16), WHICH IS AN S&P REPORT NOTING NEGATIVE CREDIT TRENDS IN THE UTILITY INDUSTRY. DO YOU BELIEVE THAT THIS REPORT IS DIRECTLY APPLICABLE TO CONSUMERS ENERGY?**

A. No. The quoted information from the report noted on pages 21 and 22 of Mr. Bleckman's testimony is fairly generic. The key areas of concern on page 11 of the report, which Mr. Bleckman omitted, are higher interest rates, changes to inflation, delays of offshore wind projects, and rising taxes. On pages 7 and 8, the S&P report also points to concerns with wildfire risks for utility companies west of the Mississippi River.

Most of these risks do not apply to the Company. First, CMS Energy and Consumers have no off-shore wind projects. Second, the projected test year ratemaking construct used in Michigan permits utility companies to recover projected costs and CPI inflationary increases for O&M expenses and capital expenditures in setting new rates. Third, regarding "higher interest rate risk", most of the Company's debt is long-term fixed-rate debt with only seasonal short-term debt which are forecasted for the projected test year and included in rates. In contrast, other utilities may use significant short-term debt and

[124] Id.



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do not have a projected test year cost recovery mechanism. As such, the Company is in a superior position on this issue relative to other utilities.

Fourth, S&P's concerns with the potential higher tax rates at this time appears to be a minor risk. No federal legislation is currently being considered that would increase the corporate income tax rate. Interestingly, on page 16 and 17 of his direct testimony, Mr. Bleckman seems concerned that the corporate tax rate may decline from 21% to 15% and have a negative effect on the cash flow to debt coverage ratio.

In summary, the Commission should dismiss the generic utility industry concerns raised by Mr. Bleckman pertaining to the S&P report, as inapplicable to the Company's regulatory and financial position.

**Q. ON PAGE 16 OF HIS TESTIMONY, MR. BLECKMAN DISCUSSES THE POTENTIAL FOR NEW TAX LEGISLATION THAT COULD AFFECT THE COMPANY'S CASH FLOW AND HE SUGGESTS THAT THIS ISSUE BE CONSIDERED AS A FACTOR IN DETERMINING THE COMPANY'S ROE RATE AND EQUITY RATIO IN THIS RATE CASE. DO YOU AGREE?**

A. No. Any discussion of reductions in the federal corporate income tax rate is pure speculation. No such tax reduction proposal has been taken up by the U.S. Congress at this time. Until such a time that tax legislation is passed and evaluated within a rate case, the Commission should disregard the speculative proposition advanced by Mr. Bleckman.

Q. **YOU STATED EARLIER THAT COMMON EQUITY CAPITAL INFUSIONS INTO CONSUMERS ENERGY BY THE PARENT COMPANY ARE BEING FUNDED TO SOME EXTENT BY LONG TERM DEBT. PLEASE EXPLAIN.**

A. There are several issues in the financial transactions between Consumers Energy and its parent company, CMS Energy ("CMS"), which cannot be ignored when analyzing the Company's proposed capital structure. First, CMS can make the Company's common equity ratio whatever it wants. The same executive management that runs CMS Energy also operates the Company. Management can direct at any time how much in capital it wants to inject into the Company from the parent company and call it equity capital. In fact, it has done just that over the years. In response to a discovery request, the Company has stated that the injection of common equity from CMS Energy is at the discretion of management with no approval from the Board of Directors.[125] Such freedom to call for equity capital would not exist if Consumers Energy itself was a publicly traded company.

Over the five years 2020 to 2024, Consumers Energy's Common Equity has increased from $7.7 billion at year end 2019 to $11.4 billion in 2024, which is an increase of $3.7 billion. An analysis of the Company's financial statements filed with the Securities and Exchange Commission shows that the $3.7 billion increase is due to the following factors:

[125] CECo response to discovery request U-18322-AG-CE-439.

**Table 1**

**Consumers Energy**

**Common Equity Change for Five Years (Dec. 2020 - 2024)**

| | | $ Billions |
|---|---|---|
| 1 | Net Income of Consumers Energy | $ 4.5 |
| 2 | Dividends Paid to CMS | (3.6) |
| 3 | Return of Capital | (0.3) |
| 4 | New CMS Investment in Consumers Energy | 3.1 |
| 5 | **Total Change in Common Equity** | $ 3.7 |

**Table 2**

**CMS Energy**

**CMS Funds Available to Invest in Consumers Energy (Dec. 2020 - 2024)**

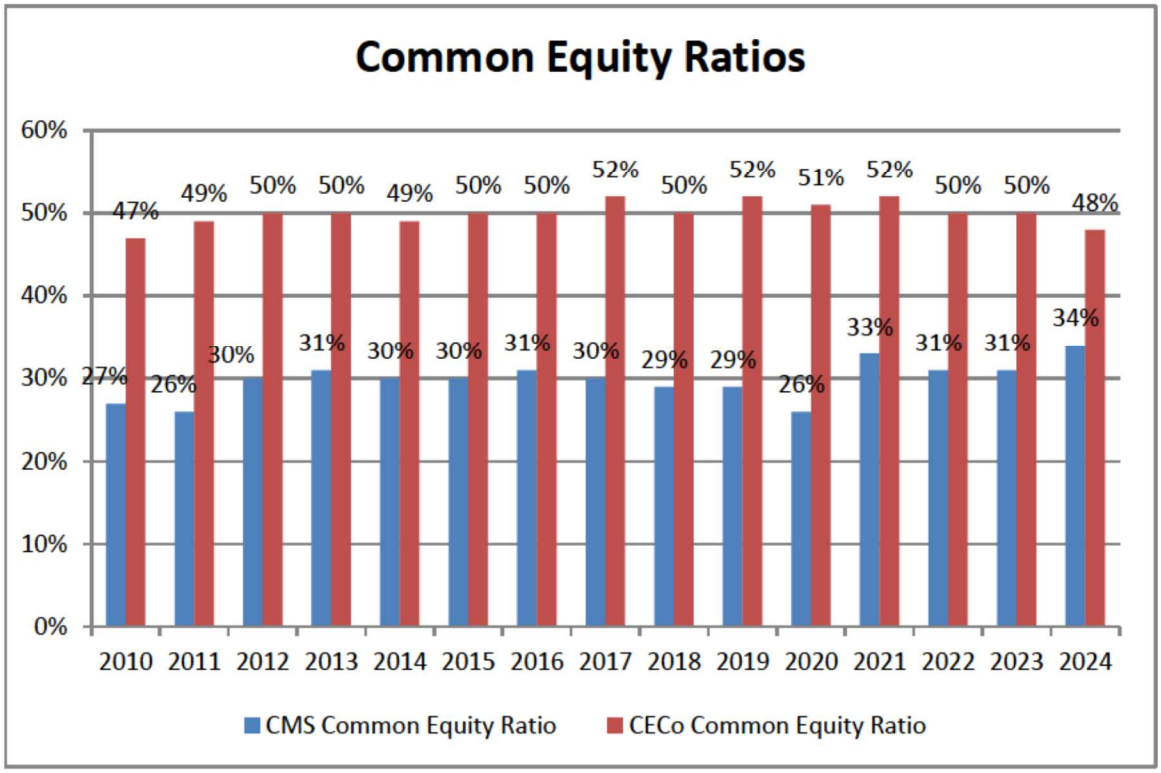
| | | $ Billions |
|---|---|---|
| a. | Dividends From Consumers Energy | $ 3.6 |
| b. | Less: Dividends to CMS Shareholders | (2.7) |
| c. | CMS Net Equity Issued | 0.8 |
| d. | Increase in CMS Equity Capital | 1.7 |
| e. | Increase in Parent Company Debt | 1.7 |
| f. | Other CMS Changes | (0.3) |
| g. | **Funds From CMS Invested in Consumers Energy** | $ 3.1 |

Clearly, as shown in table 2 above, of the $3.1 billion of new equity invested by CMS into Consumers, $1.7 billion (or 55%) is from new CMS debt (line e versus line g).

Second, to further support my point, CMS Energy is a frequent issuer of long-term debt in the capital markets. Over the last five years, CMS parent-only debt increased $1.7 billion

from $3.3 billion at year end 2019 to $5.0 billion at year end 2024.[126] Yet the only substantive business CMS Energy owns is Consumers Energy.

The following chart displays the gap in equity capital between Consumers Energy and CMS over the years 2010 to 2024. While cash raised from the issuance of long-term debt at CMS is not immediately injected into Consumers Energy, it is nonetheless being utilized in part to fund CMS's so-called equity infusions into CECo.




[126] From SEC filings on Form 10-K for the years ended 2020 (p. 124) and 2024 (p. 123).



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It is important to remember that nearly 95% of CMS' assets and revenue come from Consumers Energy.[127] Therefore, from a practical operating standpoint, CMS and Consumers Energy are one and the same.

My analysis clearly shows that CMS is using a form of double leverage by using debt capital to make its equity infusions into Consumers Energy. Although a strong argument could be made that the common equity capital of the Company should be less than 50% given the evidence I have presented, the Commission certainly should not permit a capital structure with common equity capital above 50%.

From the statements in Moody's credit reports and similar concerns expressed by other rating agencies, it appears that the debt-laden capital structure of CMS has contributed to a lower debt rating than the Company could have achieved if CMS was capitalized with more equity capital. For example, on page 1 of the May 31, 2023 credit report, Moody's states:

> Consumers Energy's stand-alone financial performance has historically been affected by the significant debt at its parent company CMS Energy Corporation (CMS, Baa2 stable). However, CMS has made notable progress in reducing the percentage of parent debt in its capital structure over the last 2-3 years. We now estimate that the percentage of parent debt will remain around mid-20% of total consolidated debt.

Similarly, on page 2 of the February 13, 2023 credit report, Fitch Investor Service states:

> There is parent-subsidiary rating linkage between CMS Energy and Consumers Energy. Fitch determines CMS Energy's standalone credit profile (SCP) based upon consolidated metrics. Fitch considers Consumers Energy's SCP to be stronger than CMS Energy's. Emphasis is placed on Consumers Energy's status as a regulated entity. Legal ring-fencing is considered porous given the general protections afforded by economic regulation. Access and control are also evaluated as porous. CMS Energy

[127] CMS Energy 2024 Form 10K at page 171.



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> centrally manages the treasury function for all of its entities. However, both the parent and Consumers Energy issue their own long-term debt. Due to the aforementioned linkage considerations, Fitch will limit the difference between the Long-Term Issuer Default Ratings (IDRs) of CMS Energy and Consumers Energy to two notches.

The result has been higher interest costs for customers. Partially to compensate for this significant leverage at CMS, the Company now wants a higher equity ratio in the capital structure that will further increase costs to customers.

Q. **YOU STATED THAT THE COMMON EQUITY RATIO OF THE PEER GROUP USED TO ASSESS THE COST OF COMMON EQUITY IS APPROXIMATELY 47%. PLEASE EXPLAIN WHY THIS IS RELEVANT IN DETERMINING THE COMMON EQUITY RATIO FOR THE COMPANY.**

A. As shown in Exhibit AG-44, the average common equity ratio of the peer company group for 2024 was 47.3%. The cost of equity for those companies in the peer group is highly dependent on the financial risk reflected in their capital structure. Thus, it is critical to synchronize the capital structure of the Company to the peer group average as closely as possible, in order to have consistency with the cost of equity capital derived from those peer group companies. The Company's proposed common equity capital ratio of 50.75% creates a disconnect that is not acceptable and is also more costly to customers.

**Q. WITNESS BLECKMAN SPONSORS EXHIBIT A-32 (MRB-10) SHOWING THE COMMON EQUITY RATIOS FOR VARIOUS GAS AND ELECTRIC UTILITY COMPANIES SUPPOSEDLY DECIDED IN RATE CASES DURING 2020 TO**

**2024. THE EXHIBIT SHOWS AN AVERAGE COMMON EQUITY RATIO OF 54.05%. DO YOU FIND THIS EXHIBIT WORTHY OF CONSIDERATION?**

A. No. It appears that Mr. Bleckman's purpose in presenting this exhibit showing an average common equity ratio of 54.05% is an attempt to support his recommended 50.75% equity ratio and to suggest that his rate is conservative and very reasonable compared to the equity ratios approved for other utility companies. The caption in column (c) of this exhibit is "Proxy Group Company". Yet, units of Black Hills, WEC Energy and CenterPoint Energy are not in the Company's peer group. As such, 16 of the 30 companies shown in this exhibit, or approximately one-half of the listed utilities are not in the Company's peer group in this rate case.

The Commission should not rely on the information provided by Mr. Bleckman in Exhibit A-32 because it is neither accurate nor comprehensive to provide a proper context to establish an appropriate common equity ratio for the Company. He presents only selective information. The major flaws are discussed below.

First, several of the companies in the exhibit reflect equity ratios calculated based on only long-term debt and common equity when the commissions in those jurisdictions also included a permanent layer of short-term debt as part of the permanent capital structure. The reality of the situation is that short-term debt is employed as a permanent financing tool, which results in a lower equity ratio if taken into account. Spire Missouri is one such company. A review of Mr. Bleckman's workpapers show the capital structure from the rate case as being 49.66% common equity, 41.83% long-term debt and 8.51% short-term

debt. For purposes of Exhibit A-32 (MRB-10), Mr. Bleckman recomputes a 54.28% equity ratio by looking only to common equity and long-term debt. Other companies have short-term debt factored into the rate-making capital structure as permanent financing, which lowers the equity ratios presented by Mr. Bleckman. The Commission should recognize that while CECo uses short-term debt strictly as a seasonal financing tool, many other companies use it both to meet short-term and long-term needs.

Second, several of the companies in Exhibit A-31 are relatively smaller utilities in comparison to Consumers Energy. Smaller utilities tend to have higher equity ratios to sustain them during potential volatility in their business, which larger utilities can better manage. For example, line 10 of this exhibit shows Cheyenne Light Fuel and Power with a 52% equity ratio. This small utility sells gas and electricity to approximately 80,000 customers in Wyoming. Another small utility on line 11 of the exhibit is CenterPoint's Arkansas operation with a capital base of only $658 million according to Mr. Bleckman's workpapers.

Mr. Bleckman also included North Shore Gas with 55.58% equity ratio when this company's rate base is approximately $450 million in 2024.[128] In contrast, Consumers Energy's electric rate base was $13.8 billion in 2023, and when including the gas business, the total company rate base is in excess of $22 billion with revenues of $7.2 billion for 2023, serving 3.7 million electric and gas customers.[129]. Also, the Atmos subsidiaries in

[128] Page 19 of the WEC Energy Group 2023 Form 10-K.
[129] Consumers Energy Exhibit A-1, Schedule A-1, in Case No. U-21490 and U-21585

all states, except for Texas, reflect smaller units with rate base of $600 million or less suggesting a "small company size" factor could be behind the higher equity ratios.

In summary, Mr. Bleckman has constructed a selective group of utilities in Exhibit A-32 that are not representative of the gas utility industry or the Company's peer group with the simple objective to create an inflated average equity ratio. For example, utilities on the east coast of the United States were not represented in Mr. Bleckman's exhibit, where equity ratios and ROEs tend to be lower and more conservative. The Commission should disregard the Company's attempt in Exhibit A-32 to present a misleading industry average equity ratio that is disconnected from the calculations of the cost of equity capital of the companies in the peer group.

**Q. WHAT IS THE REVENUE REQUIREMENT SAVINGS RELATED TO A LOWER COMMON EQUITY RATIO OF 50.0% IN COMPARISON TO THE COMPANY'S PROPOSED EQUITY RATIO OF 50.75%?**

A. The difference is approximately $8.0 million annually. This reflects (a) the difference between the pre-tax cost of common equity of approximately 14.1% versus the cost of long-term debt of 4.3%; (b) the Company's proposed rate base of approximately $11.8 billion; and (c) the percentage of total capital being shifted from common equity to long term debt.

**Q. DID YOU MAKE ANY OTHER ADJUSTMENTS TO OTHER ITEMS INCLUDED IN THE COMPANY'S PROPOSED CAPITAL STRUCTURE?**

A. No. Except for the common equity and long-term debt balances which I have changed (as explained earlier in my testimony), I have utilized the capital balances sponsored by witness Bleckman in Exhibit A-14 (MRB-1), Schedule D1, page 1.

## COST OF CAPITAL

**Q. WHAT RETURN ON EQUITY AND OVERALL RETURN ON CAPITAL ARE YOU RECOMMENDING IN THIS CASE?**

A. I am recommending an overall return on capital of 5.97%, which includes a return on common equity of 9.75%, as shown in Exhibit AG-41. Even though the average ROE calculated under the three methods discussed below is slightly less than 9.75%, I have used a 9.75% ROE rate to calculate the overall cost of capital for reasons I will explain later in my testimony.

**Q. WHAT COST RATE DID YOU UTILIZE FOR LONG TERM DEBT?**

**A.** For the long-term debt cost rate, I used a rate of 4.35% based upon Mr. Bleckman's recommendation.

**Q. WHAT COST RATE DID YOU UTILIZE FOR PREFERRED STOCK?**

A. For the preferred stock, I used a 4.5% rate, consistent with the rate recommended by Company witness Bleckman.

**Q. WHAT COST RATE DID YOU UTILIZE FOR SHORT TERM DEBT AND THE OTHER COMPONENTS OF THE CAPITAL STRUCTURE?**

A. For Short Term Debt and Deferred Taxes, I used the cost rates recommended by witness Bleckman. Cost rates for JDITC reflect those rates I used for the permanent capital sources.

**Q. PLEASE EXPLAIN THE DEVELOPMENT OF THE OVERALL COST OF CAPITAL IN EXHIBIT AG-41.**

A. To develop the overall cost of capital on line 12, column (f), I have first developed the percentage weighting of each capital component in column (d) by dividing the individual capital balances in column (b) by the total of all capital components in that column. Next, I have multiplied the weightings in column (d) by the cost rates in column (e) to arrive at the values in column (f). The total of the individual values in column (f) is the total cost of capital of 5.97%.

Regarding the pretax weighted cost of capital on line 12, column (h), I have multiplied each cost component in column (f) by the conversion factors in column (g). These conversion factors are included to reflect the impact of income and other taxes paid by CECo for calculation of the pretax weighted cost of 7.36% in column (h).

**Q. WHAT GENERAL PRINCIPLES HAVE YOU CONSIDERED IN DETERMINING THE COST OF COMMON EQUITY FOR THE COMPANY?**

A. A utility company is entitled to a fair return that will allow it to attract capital and be sufficient to assure investors of its financial soundness. In its opinion in Bluefield Water

Works and Improvement Company v Public Service Commission of West Virginia (the "Bluefield Case") 262 U.S. 679 (1923), the United States Supreme Court indicated that:

> *"A public utility is entitled to such rates as will permit it to earn a return on the value of the property which it employs for the convenience of the public equal to that being made at the same time…on investments in other business undertakings which are attended by corresponding risks and uncertainties; but it has no constitutional right to profits such as are realized or anticipated in highly profitable enterprises or speculative ventures. The return should be reasonably sufficient to assure confidence in the financial soundness of the utility and should be adequate, under efficient and economical management, to maintain and support its credit and enable it to raise the money necessary for the proper discharge of its public duties…"*

The principals of the Bluefield Case were re-affirmed by the U.S. Supreme Court in 1944 in the case FPC v Hope Natural Gas Company, 320 U.S. 591.

**Q. PLEASE EXPLAIN THE DEVELOPMENT OF THE COST OF COMMON EQUITY IN EXHIBIT AG-42.**

A. Determining the cost of common equity for an enterprise or an industry group is inexact since investors can only estimate what the future cash flows from any enterprise may be over time. Because of this uncertainty, most financial experts will not rely solely on any particular method. To determine the cost of common equity, I have utilized three approaches to assess this cost. These are the Discounted Cash Flow (DCF) Method, the Capital Asset Pricing Model (CAPM), and the Utility Risk Premium approach.

While Exhibit AG-42 shows an average ROE of 9.52% from the three methodologies, I recommend an allowed rate of return on equity of 9.75% for the reasons explained later in this section of my testimony. In connection with these methods for determining the cost

of common equity, I have considered the cost of common equity for a proxy group of peer companies.

Q. **PLEASE EXPLAIN THE DEVELOPMENT OF YOUR PROXY GROUP OF PEER COMPANIES.**

A. To develop an appropriate peer group, I started with the 9 utility companies followed by the Value Line Investment Survey in its "Natural Gas Utility Industry" section. I eliminated two of these companies from consideration which are (a) New Jersey Resources because it earns less than 50% of its income from the utility business; and (b) UGI Corporation due to its foreign investments and heavy reliance on propane sales.

Additionally, I have added one other company to my peer group which Value Line classifies as an electric utility. The additional company is Black Hills. This company earns approximately 50% of its income from natural gas distribution and as such is suitable to be included in CECo's natural gas distribution peer group.

The result is the group of eight companies shown in Exhibit AG-43, all of which have growing earnings and dividends.

**Q. HOW DOES YOUR PEER GROUP COMPARE TO THE COMPANY'S PEER GROUP?**

A. The Company's peer group contains six of the companies in my peer group. Potential peer companies excluded by the Company's witness were Chesapeake Utilities and Black Hills.

Chesapeake was excluded because it did not have a bond rating in 2024, which it now has with a rating of "A-" by Fitch. Black Hills presumably was excluded because Value Line classifies it as an electric utility even though its sales to gas customers represented 54% of total Operating Income in 2024.

***Discounted Cash Flow (DCF) Cost of Equity Method***

**Q. PLEASE DESCRIBE THE DISCOUNTED CASH FLOW ("DCF") APPROACH.**

A. The DCF approach is based on the proposition that the price of any security reflects the present value of all future cash flows (dividend flows) from the security discounted at a single discount rate which, in the case of common stocks, is the required return on equity. Expressed mathematically, the resulting equation can be reconfigured to solve for the required rate of return and this equation is:

$$R = D/P + g$$

*where "R" = the Required Equity Return*
*"D/P" = the Dividend Yield on the Security*
*and "g" = the expected growth rate in dividends*

**Q. PLEASE EXPLAIN THE RESULTS OF YOUR DCF ANALYSIS.**

A. The results of my DCF analysis are summarized in Exhibit AG-43. The stock price information in column (c) of this exhibit reflects the average of the high and low prices for each of these equity securities on each of the 30 trading days from February 3 to March 17, 2025. The annual dividend in column (d) is the forecasted average dividend level for 2025 and 2026 as projected by the Value Line Investment Survey. Column (h) shows the

average long-term earnings growth rate based on (1) the estimate of earnings growth through 2029 per Value Line; and (2) the earnings growth estimates per Zacks as included in the Company's DCF analysis.

The resulting calculation of the DCF Method is an average return on common equity for the proxy group of 9.11%.

**Q. PLEASE ASSESS THE RESULTS OF THE DCF ANALYSIS YOU PERFORMED.**

A. The DCF analysis relies upon financial market information for the dividend yield portion of the equation. It also relies upon judgments of dividend and earnings growth prospects of security analysts which reflects the consensus of the market on which investors rely. Therefore, I place a fairly high degree of reliability in the DCF results when considered in conjunction with the results of other methods in determining the cost of common equity.

**Q. HOW DOES YOUR DCF COST OF CAPITAL ESTIMATE COMPARE TO THE COMPANY'S DCF ESTIMATE?**

A. The results of my DCF analysis and those of witness Bulkley are dependent in large part upon the overall dividend yield in each case as well as the average growth rate of each peer sample. Company witness Bulkley's DCF result of 9.87% is 76 basis points higher than the 9.11% DCF result I calculated.[130]

[130] This Company's 9.87% DCF ROE rate is shown on page 1 of Exhibit A-14 (AEB-1).

The dividend yield in my analysis is 3.5% but the Company's is higher at 3.71%. This accounts for approximately 30% of the 76-basis point difference. Also, the projected growth rate is higher in the Company's case at 6.05% vs. 5.57% in my analysis.[131] I will point out that the data on the dividend yield and the earnings growth rates used by the Company were compiled sometime in the fourth quarter of 2024 and are now stale. The stock prices of the utilities in the peer group are now higher, thereby justifying a lower dividend yield compared to the Company's filed case. Also, the growth rates that I used include results for Black Hills and Chesapeake Utilities which are slightly lower than the six companies in the Company's peer group, resulting in a lower average earnings growth rate for the peer group. Therefore, the more recent information I included in my peer group analysis provides an updated and reasonable DCF result of 9.11%.

***Capital Asset Pricing Model***

**Q. PLEASE EXPLAIN THE CAPITAL ASSET PRICING MODEL (CAPM) APPROACH TO DETERMINING THE COST OF COMMON EQUITY CAPITAL.**

A. The Capital Asset Pricing Model (CAPM) is based on the proposition that the expected return on a common equity security is a function of risk as measured by the "Beta" of that security. In equation form, CAPM is as follows:

$$k_e = R_f + (B \times R_p)$$

*where* $k_e$ = *The market cost of common equity for a specific security*

$R_f$ = *the "risk free" rate of return*

[131] The 3.71% dividend yield and 6.05% growth rate of the Company's peer group analysis is from page 3 of n Exhibit A-14 (AEB-1)

*$R_P$ = the overall return of the market less the risk-free rate (over several years)*

*B = the systematic risk of a particular common equity security vs. the market*

**Q. PLEASE EXPLAIN THE BETA OR "*B*" COMPONENT OF THE EQUATION.**

A. This measure of risk reflects the extent to which the price of a particular security varies in relationship to the movement of the overall market. Securities that vary over time more than the overall market will have a Beta that is greater than 1.00. Some securities vary less in price over time than the overall market. In these cases, the Beta will be less than 1.00. Utility stocks tend to move less than the overall market. Reflective of this outcome, the average Beta of my Peer Group is 0.91.

**Q. PLEASE EXPLAIN EXHIBIT AG-44 SHOWING THE RESULTS OF THE CAPM APPROACH.**

A. Exhibit AG-44 shows the results of the CAPM method based upon (1) a 4.0% risk-free rate; (2) the Betas of the companies in the Peer Group taken from Value Line; and (3) the 7.30% historical Market Risk Premium ($R_p$) return from the years 1926 to 2023.[132]

Regarding the use of a risk-free rate for CAPM purposes, I used a 4.0% rate which is the 30-year U.S. Treasury Bond for the second quarter of 2026 sourced from economic projections provided by the Company.[133]

[132] WP-AG-44.
[133] Discovery response AG-CE-440 showing a 4.0% 30-Year U.S. Treasury rate.

The result of my CAPM approach using the 6.66% adjusted risk premium (7.30% Risk Premium x 0.91 Beta) plus the 4.0% risk-free rate is a cost of equity capital of 10.66% for the proxy group average.

**Q. PLEASE ASSESS THE CAPM APPROACH.**

A. I believe that CAPM has value in assessing the relative risk of different stocks or portfolios of stocks. As such, it can be useful. However, the key issue with CAPM is that it assumes that the entire risk of a stock can be measured by the "Beta" component. As such, the only risk to the investor is from fluctuations in the overall market. In actuality, investors take into consideration company-specific factors in assessing the risk of each particular security. Therefore, I give the CAPM approach less weight than the DCF approach in determining the cost of common equity.

***Utility Risk Premium Approach***

**Q. PLEASE EXPLAIN THE UTILITY RISK PREMIUM APPROACH OF ESTIMATING THE COST OF COMMON EQUITY.**

A. In general, the cost of common equity for a peer group of utility companies can be estimated by (1) projecting the cost of debt for the peer group and adding to this cost (2) the average return differential of utility common stocks over utility bonds.

**Q. PLEASE EXPLAIN YOUR UTILITY RISK PREMIUM ANALYSIS RESULTS.**

A. Exhibit AG-45 shows the components required to derive a cost of common equity capital for the peer companies on lines 3 and 4. The 5.40% on line 3 is the projected average rate for utility bonds rated "A" and "BBB". This rate is determined in footnote 2 of the exhibit from average spreads of 30-year utility bonds in 2024 compared to 30-year U.S. Treasury bonds. The spread rate of 3.80% on line 4 of the exhibit is the historical rate of gas utility returns versus "A" rated debt yields from 1952 to the present. The total of the two rates equals the Risk Premium return rate of 9.20% on line 5 of the exhibit.

**Q. DOES THE COMPANY PROVIDE A UTILITY RISK PREMIUM ANALYSIS?**

A. No, not in the traditional sense of measuring achieved returns on utility stocks relative to an interest rate benchmark such as utility bonds. Instead, Company witness Bulkley uses an unorthodox approach she refers as Bond Yield Risk Premium (BYRP).

**Q. PLEASE SUMMARIZE WITNESS BULKLEY'S TESTIMONY ON PAGES 30 THROUGH 33 STARTING UNDER THE HEADING "BYRP ANALYSIS" ON PAGE 30.**

A. Witness Bulkley states in her testimony that she compared authorized ROEs from gas utility rate case decisions from 1980 to 2024 and compared the authorized ROEs to 30-year U.S. bond yields. She ran a regression model with this data and claims to have found a strong relationship between these bond yields and authorized ROEs. Based on the results of the three cases prepared using this approach, she concludes that the average risk premium over the 1980-2024 period is 6.12%. To this 6.12% developed risk premium,

she adds an estimated rate of 4.13% for the 30-year U.S. bond yield for the projected test year to arrive at a 10.25% ROE rate for the projected test year under this unorthodox approach. The calculation is shown on page 22 of Exhibit A-14.

**Q. WHAT IS YOUR ASSESSMENT OF THE BYRP APPROACH PRESENTED BY MS. BULKLEY?**

A. There are three major flaws with Ms. Bulkley's Bond Plus Risk Premium methodology. First, it lacks any comparison of actual utility returns achieved from price appreciation and dividends to bond yields. It is the actual return on utility common equities that is the key and necessary measurement in any risk premium analysis. Using authorized ROEs as a substitute ignores investors' return expectations. Second, the analysis is biased because it covers a period when interest rates were declining from 12.1% in late 1980 to 4.2% in 2024[134].

Third, this analysis assumes a direct relationship between declining interest rates and ROE decisions as happening almost instantaneously on a monthly basis. Regulators approach the serious business of establishing ROEs based on many factors including the concept of gradualism in reducing or increasing ROEs that are not in lock step with interest rate changes. This analysis has no validity as a tool to determine an appropriate ROE rate in rate case proceedings.

[134] Exhibit A-14 (AEB-1) pages 23 and 25

**Q. HOW DO YOUR CAPM AND MARKET RISK PREMIUM RESULTS COMPARE TO THE RESULTS PRESENTED BY COMPANY WITNESS BULKLEY?**

A. Ms. Bulkley presents the results of her projected CAPM, Projected ECAPM, and Projected Risk Premium methods in Exhibit A-14, page 1. In the table below, I show the development of Ms. Bulkley's CAPM ROE results compared to mine.

**Comparison of CAPM Estimates of AG and Company High Case**

| Line | | AG Case* | Company High Case** |
|---|---|---|---|
| 1 | Market Risk Premium (MRP)*** | 7.30% | 7.74% |
| 2 | Beta (based on proxy group companies | 0.91 | 0.875 |
| 3 | MRP x Beta | 6.66% | 6.77% |
| 4 | Risk Free Rate | 4.00% | 4.30% |
| 5 | **CAPM Result (L 3 + L 4)** | **10.66%** | **11.07%** |

* Exh. AG-44.
** Exh. A-14, p. 8 of 29.
*** Company MRP = 12.04% less T bond Rate.

Key differences noted above are a higher Market Risk Premium and a higher Risk-Free Rate, both of which are discussed below. The Company's ECAPM results are all slightly higher than the CAPM results in the table above due to the different approach used. This is discussed below in my testimony.

**Q. PLEASE EXPLAIN THE COMPANY'S DECISION TO USE A 4.30% RATE FOR THE 30-YEAR U.S. TREASURY RATE AS THE RISK-FREE RATE AND YOUR**

**ASSESSMENT REGARDING THE USE OF THIS RATE TO DEVELOP THE ROE ESTIMATES FOR THE PROJECTED TEST YEAR.**

A. The Company developed multiple CAPM ROE estimates using 4%, 4.07%, and 4.30% Risk-Free rates. The Company's use of multiple rates seems to be a hunt for an approach that will result in a higher ROE rate. The use of the higher 4.30% 30-year forecasted U.S. Treasury bond rate is particularly flawed because it reflects U.S. Treasury rates forecasts for 2026 to 2030, which in large part includes periods beyond the test year ending October 2026. Instead, I used the single rate of 4.00% for the 30-year U.S. Treasury bond rate forecasted for the first quarter of 2026, which is about the mid-point of the projected test year.[135]

**Q. PLEASE PROVIDE YOUR ASSESSMENT OF THE COMPANY'S CALCULATED MARKET RISK PREMIUM OF 7.74%.**

A. Instead of using a proven historical market risk premium (MRP), the Company developed its MRP based largely on future expected stock price growth rates and dividends for a select group of companies from the S&P 500 stock index over the next three to five years**.** Based on her sample of companies, Ms. Bulkley calculates a forecasted stock market return of 12.04%. From this percentage, she deducts the forecasted 30-year U.S. Treasury risk-free rate of 4.30% to arrive at a forecasted of 7.74%.

[135] Discovery Response AG-CE-0440

There are a number of problems with this approach to developing an MRP. First, short-term fluctuations in expectations and projections of stock market returns for the sample companies can cause the forecasted MRP rates to vary significantly. Second, as can be seen from an examination of pages 16 to 21 of Exhibit A-14, many of the companies with dividend yields and long-term growth estimates are omitted. Approximately 125 companies or 25% of the named companies in the S&P 500 are not represented in the calculation of the 12.04% stock market return. In contrast, many large technology companies with high growth prospects have a larger than normal weighting in the calculation of the 12.04% return due to their relatively large market capitalization.

**Q. PLEASE EXPLAIN FURTHER THE SHORTCOMINGS WITH THE MARKET RISK PREMIUM DEVELOPED BY WITNESS BULKLEY?**

A. Witness Bulkley is using an extremely short period of 3 to 5 years to measure stock market returns in determining the MRP. The projected MRP does not include a complete cycle of economic expansion and contraction, which is what occurs over the long-term. To adopt the Company's approach would be akin to only selecting the positive return years over the 98-year historical period of stock market returns I used and not the losses in the downturn years. Expectedly and incorrectly, we would derive a far higher overall return for the market and far higher market risk premium, which is the flawed result achieved by witness Bulkley in the 12.04% market return and forecasted MRP.

These concerns are also echoed by Dr. Roger Morin, a recognized expert on regulatory finance matters, who strongly supports the use of the longest possible period for

calculating a market risk premium. On page 114 of his book "New Regulatory Finance" Dr. Morin states the following:

> Therefore, an historical risk premium study should consider the longest possible period for which data are available. Short-run periods during which investors earn a lower risk premium than they expect are offset by short-run periods during which investors earn a higher risk premium than they expect. Only over long time periods will investor return expectations and realizations converge. Clearly, the accuracy of the realized risk premium as an estimator of the prospective risk premium is enhanced by increasing the number of years used to estimate it…

Clearly, Ms. Bulkley's approach to calculating the projected market risk premiums is not academically or practically sound.

For the above reasons, witness Bulkley's development of the forecasted MRP used by the Company in the CAPM and ECAPM cost of equity calculations is seriously flawed and should be rejected.

**Q PLEASE COMMENT ON MS. BULKLEY'S USE OF THE ECAPM METHOD.**

The basic premise for the use of the ECAPM method is that the Beta factors published by Value Line when used in CAPM analysis do not accurately predict stock performance. However, as explained below, this argument is flawed.

Notwithstanding Ms. Bulkley's arguments, there is academic disagreement with the validity of the original studies that led to the use of ECAPM. First, the original study used raw betas and not the adjusted Value Line betas, which I use, and other cost of capital experts normally rely upon. Second, the original studies relied upon short-term risk-free

rates. Instead, cost of capital witnesses, including myself, who have been involved in the Company's rate cases use long-term risk-free rates in the CAPM model.

Dr. Morin points out this key difference on page 191 of his book "New Regulatory Finance" where he states that "…the long-term risk-free rate version of the CAPM has a higher intercept and a flatter slope than the short-term risk-free rate version which has been tested."

The ECAPM produces a faulty cost of equity rate with a bias toward overstating and inflating the true cost of equity capital. The Commission should continue to disregard this alternative approach to the traditional CAPM method.

**Q. HAVE OTHER REGULATORY COMMISSIONS WIDELY EMBRACED THE ECAPM METHODOLOGY FOR SETTING RETURN ON EQUITY RATES?**

A. No. In response to a discovery request in Case No. U-18424, the Company stated that ECAPM "… is supported by orders from regulatory bodies in Maryland, Mississippi and Alberta…" As a result of this claim, the Company was asked to provide the specific rate orders from these regulatory commissions.[136] The information provided in response to this discovery request was less than convincing.

[136] CECo responses to U-18424 AG-CE-206 and AG-CE-386.

Regarding the purported acceptance of the ECAPM in the State of Mississippi, the filing requirements of the Mississippi Commission require ECAPM filings. However, the extent to which Mississippi relies upon these estimates is unknown.

Regarding the Maryland commission, Company witness Maddipati pointed out on page 58 of his direct testimony in Case No. U-18424 that the Maryland Commission stated that they found the DCF and ECAPM "helpful" in Case 9326. However, in a more recent case involving PEPCO (case 9418) with an order issued on November 15, 2016, the result is different. As shown in the summary positions articulated in the order in this case, no party involved in the proceedings, other than the company, put forth an ECAPM ROE estimate. In this case, the Maryland commission basically adopted the Staff's position with no ECAPM estimate and rounded down the Staff's recommended ROE of 9.57% to 9.55%.

In this regard, the Maryland Commission stated on page 100 of the order the following. *"Our Decision today most closely aligns with Staff's recommendation of 9.57% although we do not expressly reach the same conclusion as Staff. We find that a slightly lower ROE of 9.55% is both adequate and appropriate for Pepco…"* Furthermore, in its decision in this case, the Maryland commission expressed no position on ECAPM. I am not aware of any more recent cases that show a change in the commission's view of the ECAPM methodology.

**Q. ON EXHIBIT AG-46, YOU PROVIDE INFORMATION REGARDING THE MIX OF UTILITY AND NON-UTILITY BUSINESSES OF THE PEER GROUP YOU**

**USE. WHAT DOES THIS ANALYSIS REVEAL ABOUT THE RISKS OF THE PEER GROUP RELATIVE TO THE COMPANY'S GAS BUSINESS?**

A. In general, the peer group has a higher degree of risk compared to the gas business of Consumers Energy. Some companies in the peer group are involved in energy ventures, energy services, and gas marketing. The non-utility, and often non-regulated, businesses place the peer group at greater risk. Also, the peer group companies are more financially leveraged with higher debt as a percentage of total capital, which makes them riskier.

**Q. PLEASE DISCUSS WHAT RETURN ON EQUITY RATES OTHER REGULATORY COMMISSIONS HAVE GRANTED IN 2023 AND 2024.**

A. Exhibit AG-48 shows the ROEs granted by state regulatory commissions for U.S. gas utilities in 2023 and 2024. The majority of the 36 ROE decisions in 2023 and 41 decisions in 2024 are at rates well below 9.9%, which is CECo's current authorized ROE.[137] As noted on page three of the exhibit, only three decisions in 2023 and nine decisions in 2024 are at rates of 9.9% or greater. These higher rates, which are summarized on page 3 of Exhibit AG-48, are primarily from regulatory commissions in California, Florida, and Michigan or pertain to small companies. ROEs in California have been at or above 10% reflecting the unique challenges for utilities in that state with wildfires and earthquakes. ROEs in Florida reflect damage to utility property and financial losses from hurricanes, which is an on-going challenge for the utilities in the state. High ROEs in other

[137] The 2023 and 2024 decisions exclude Limited Issue Rider cases.



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jurisdictions tend to reflect smaller utilities or unique geographical challenges, such as in Alaska, as shown on page 3 of Exhibit AG-48.

For most of the other gas utilities that have business and financial risks comparable to Consumers Energy's operations, the ROE rates have averaged around 9.5% in the past two years. This evidence supports my calculations of an overall cost of equity of 9.52% and suggests that the Company's current ROE rate of 9.90% is excessive and "out of line" with comparable gas utilities and the true cost of equity capital. The Company's proposed ROE rate of 10.25% is even further removed from reality and clearly unsupportable. My recommended ROE rate of 9.75% in this rate case provides a bridge to ultimately reach the true cost of capital for the Company and is quite reasonable.

I will also point out that the most current average ROE rate for the peer group of utility companies is 9.61%. Exhibit AG-50 shows that information. This is another benchmark that shows the 9.75% ROE rate I have proposed is reasonable, if not generous for the Company.

**Q. IN THIS RATE CASE, MR. BLECKMAN SPONSORS EXHIBIT A-33 (MRB-11) SHOWING THE ROE RATES AND COMMON EQUITY RATIOS OF SELECT UTILITY COMPANIES. WHAT IS YOUR ASSESSMENT?**

A. Much of the information in Exhibit A-33 is incorrect, misleading, and does not provide a proper context for the metrics noted in the exhibit. Below, I discuss the key problems with the information presented by Mr. Bleckman.

First, with regard to Florida Power & Light, the 10.60% ROE was established by the Florida Commission in 2021 as part of a multi-year agreement covering the years 2022 to 2025. Under this agreement rate increases are capped, and any other relief would be dependent upon extraordinary circumstances.[138] In addition, this Company's service territory is buffeted by hurricanes each year which can disrupt electric service for prolonged periods and potentially reduce revenues and profits. The ROE rate granted to Florida electric utilities is not applicable to Consumers Energy's gas business.

Second, Alabama Power information, a Southern Company subsidiary, shows a 55% Common Equity ratio and a 10.9% ROE. The utility may potentially increase it rates each year but on a rolling two-year basis. However, the increases are limited to no more than 8% in a two-year period or 4% on average annually. The increases are authorized under the company's Rate RSE (established before 2016) which is determined by considering the level of earned returns on equity and the percentage of equity in the capital structure based on the company's Weighted Equity Cost Rate (WECR).[139]

In 2018, the Alabama Commission and the company agreed to a higher common equity ratio of 55% by 2025 from 47% in December 2018. The change to Rate RSE for Alabama Power was approved in May 2018 with no compensating rate increases and the company at that time consented to a nominal reduction in the WECR with no annual Rate RSE increases in 2019, 2020 and 2022. Rates were increased by 4.09% in 2021, but the

[138] NextEra 2022 Form 10-K, page 9.
[139] Southern Company Form 2022 10-K starting at Page II-139 under "Rate RSE".



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Company also made refunds to customer via bill credits in the amount of $50 million for 2020, $181 million for 2021, and $62 million for 2022.[140] What is happening in this situation is that the Company is increasing the common equity ratio gradually with no compensating increases in the WECR. The practical effect of these rate actions is to reflect recognition of a lower cost of common equity. This special rate and capital structure arrangement is not applicable to Consumers Energy for purposes of establishing an appropriate ROE rate in this rate case.

Third, the exhibit shows Georgia Power, another Southern Company subsidiary, with a 56% common equity ratio and an 10.50% authorized ROE. Georgia Power has been in a special situation involving significant expenditures for two nuclear power plants where (1) the original contractor declared bankruptcy; and (2) the Company has been forced to write-off approximately $2.0 billion of cost overruns in 2021 and 2022; and (3) the Company has only recently completed one of the new nuclear units and may face uncertainty regarding the future recoverability of costs related to the new nuclear generating units.[141] The Georgia Commission has been very supportive of the company through this troubled time. The ROE and capital structure for Georgia Power are not applicable to Consumers Energy's gas business given the unusual circumstances.

Fourth, with regard to WEC, which owns gas and electric utilities in Wisconsin and other jurisdictions, the 10.16% ROE shown in the exhibit is unsupported and faulty. Recent

[140] Id.
[141] Id. page II-147.

decisions from the Wisconsin Commission in general rate cases have granted ROEs of 9.8%.[142] It appears that Mr. Bleckman may have increased the ROE rate in his chart by including Limited Issue Riders. These riders are not applicable to a general rate case and not applicable to Consumers Energy in this proceeding.

Fifth, for UGI, all of this utility's recent general rate cases in 2020 through 2024 have been settled without published rate metrics. So, the information shown in this exhibit is stale or inapplicable.

In summary, Mr. Bleckman's attempt to inflate his ROE recommendation by pointing to select and inapplicable ROE rates granted to other utilities fails to provide convincing evidence and should be rejected by the Commission.

**Q. SHOULD THE COMMISSION BE CONCERNED THAT ESTABLISHING AN AUTHORIZED ROE BELOW 9.90% IN THIS CASE WILL LEAD TO IMPAIRMENT OF THE COMPANY'S ABILITY TO ACCESS THE CAPITAL MARKETS?**

A. No. From time to time in general rate case proceedings, certain rate case applicants, including the Company, have raised arguments that they should receive higher ROEs to ensure the financial soundness of the business and to maintain its strong ability to attract capital in addition to being compensated for risk. However, those concerns are not supported by the evidence. Exhibit AG-48 shows several gas utilities that have accessed

[142] Regulatory Research Associates 2024 Report.

the capital markets at competitive interest rates since receiving a ROE near or below the average rate of 9.50%.

Similarly, there is no evidence equity investors have abandoned utilities that have been granted ROEs near or below the industry average. On the contrary, stock investors continue to migrate to utility stocks, recognizing that authorized ROEs are still above the true cost of equity. Exhibit AG-47 shows the market to book ratios for each of the peer group companies, and many of these companies have received rate orders during the past few years reflecting ROEs as low as 9.37%. Yet this group of companies has an average Market to Book common equity value ratio of approximately 1.5 times.

A market to book value greater than 1.0 shows that investors are attracted to the return (ROE) earned by utilities on their book value. A higher market to book ratio indicates that the utility is earning a higher return on book value than other utilities. It also indicates that the utility is earning a return on book value that is higher than the investor expects for that type of investment and is willing to pay a higher market price for the stock than book value.

This information is provided to dispel the myth that the Company must receive a high ROE above the industry average, or it will face dire consequences in the financial markets.

The fact that the Company needs to raise capital because of a large capital investment program to upgrade its infrastructure and for other purposes is not unique to Consumers Energy. Most gas utilities face the same issues and are able to raise capital with ROEs at or near the 9.5% average rate. Therefore, this issue is another "red herring".

**Q. ON PAGE 52 OF ITS SEPTEMBER 13, 2018 ORDER IN CASE NO. U-18999, THE COMMISSION POINTED TO INCREASED VOLATILITY IN THE CAPITAL MARKETS AS A REASON TO AUTHORIZE A 10% ROE RATE. SHOULD STOCK MARKET VOLATILITY OR THE VIX INDEX BE A CONCERN IN ESTABLISHING A FAIR ROE RATE FOR THE COMPANY?**

A. No. The stock market has historically been very volatile. Currently, this is measured by the VIX, which portrays volatility over the next 30 days. In some periods, stock prices move up and down more dramatically than at other times. The key factor is that the VIX is telling us something about risk in the market over the next 30 days and not the risk several months in the future. In setting ROE rates for utilities, the Commission's focus is the long-term financial health of the utility not the short-term gyrations of the stock market.

As a supporting point, in Exhibit AG-52, I have included a Value Line Funds article written by Mitchell Appel, President of Value Line Funds. Mr. Appel states that volatility is not risk. He also points out that volatility in 2017 was low by historical standards and it was near normal levels in 2018. Mr. Appel goes on to say later in this article that "…volatility is only risk if you act during down times, that is, only if you sell a stock." This principle still applies to events today.

Additionally, I will submit that those who invest money in equity portfolios over longer periods of time and particularly in utility stocks have an aversion to market volatility and the VIX. In fact, utility stocks are a safe haven for investors during times of uncertainty and volatility because they are not as susceptible to volatility as the general stock market.

This is reflected in the average Beta value of 0.91 of the utility peer group used in the CAPM discussed earlier, in contrast with the general stock market value of 1. The recent stock market volatility in April 2025 due to the imposition of trade tariffs is an example where utility stocks have outperformed the general stock market as a safer heaven for investment.[143] Therefore, the Commission should not give any weight to arguments that the Company's ROE should reflect investors' concerns with stock market volatility.

**Q. HAS THE MARKET FOR NEW LONG-TERM DEBT BEEN RECEPTIVE TO NEW UTILITY DEBT ISSUES IN 2023 AND 2024?**

A. Yes. As shown on Exhibit A-31(MRB-9), the market for new utility debt issues has been very robust with over 350 new issues completed in 2023 and the first nine months of 2024. Also, as can be seen from Exhibit AG-48, a large number of utility companies issued new debt shortly after receiving a rate order with ROEs below 9.50%.

Consumers Energy issued $700 million of long-term debt in July 2024 at an interest rate of 4.7% and a 5-year term. Also, in January of 2024, Consumers Energy issued $600 million of new 10-year debt at an interest rate of 4.6%. CMS Energy has also come to market and issued $1.0 billion of new 30-year debt at a rate of 6.5%. On my Exhibit AG-48, I show several utility companies who came to market not long after a rate case decision and issued significant quantities of new long-term debt.

[143] From the end of 2024 and through April 15, 2024, CMS Energy Stock is up 9.1% while the S&P 500 Index is down 8.2%.

Accordingly, the debt markets are receptive to utility companies' capital raising activities.

**Q. PLEASE EXPLAIN YOUR CONCLUSION CONCERNING THE APPROPRIATE RETURN ON EQUITY RATE THAT THE COMMISSION SHOULD APPROVE IN THIS RATE CASE.**

A. In Exhibit AG-42, I summarized the cost of equity rates from the three methods I discussed above. The range of returns for the industry peer group is from 9.11% at the low end, using the DCF approach and 10.66% at the high end using the CAPM approach.

As explained earlier in my testimony, I give 50% weight to the DCF method as a more reliable approach to estimating the cost of equity for a utility, which from my analysis is a rate of 9.11%. In this regard, on line 4 of Exhibit AG-42, I have calculated a weighted return on equity from the three methodologies using a 50% weight for DCF and 25% for each of the other two methods. The result is a weighted average cost of common equity of 9.52%. To this base cost of equity capital, I have added an additional premium adjustment of 23 basis points to arrive at a recommended ROE rate of 9.75% for Consumers Energy's gas business. I have added this additional ROE cushion to the calculated cost of capital due to the uncertainty of the timing in the decline in interest rates in the coming year. The 23-basis points cushion compensates for a potential increase in the 4.0% risk-free rate I used in the calculation of the cost of equity. Therefore, there is no need to further increase the ROE rate above the 9.75% for further interest rate risk and I urge the Commission to adopt this proposed rate.

**Q. IF THE COMMISSION APPROVES A 9.90% COST OF COMMON EQUITY IN THIS CASE, AS IT DID IN CASE NO. U-21585, WHAT IS THE ADDITIONAL COST TO CUSTOMERS COMPARED TO AN ROE OF 9.75%.**

A. If the Commission were to grant a 9.90% ROE in this case versus a 9.75% ROE, the additional cost to customers is approximately $10 million annually. There is absolutely no need to burden customers with this additional cost, when historically the Company has been earning well above its true cost of common equity.

I recommend that the Commission take note of the evidence and arguments I have presented in my testimony and grant the Company a ROE rate of no more than 9.75%.

## IX. Revenue

## Gas Sales and Transportation Revenue

**Q. WHAT ARE YOUR FINDINGS FROM ANALYZING THE COMPANY'S PROJECTED LEVEL OF GAS SALES AND TRANSPORTATION VOLUMES?**

A. In Exhibit A-15 (MA-6), Schedules E-2, Company witness Mustafa Ahmed presents the Company's forecast of gas sales and transportation deliveries for the projected test year ending October 2026. The Company forecasted total gas sales of 223.8 billion cubic feet (Bcf) and end-user transportation deliveries of approximately 84.0 Bcf for total gas deliveries of 307.7 Bcf for the projected test year. The projected sales represent an increase of approximately 4.0 Bcf from the most recently available actual weather-normalized sales

in 2024, while the projected transportation gas volumes represent a decrease of 0.5 Bcf from weather-normalized 2024 volumes.[144]

According to Mr. Ahmed's direct testimony and responses to discovery, the Company calculated the forecasted sales and transportation volumes based on various regression projection models applied to customers' historical gas consumption during the January 2013 to March 2024 timeframe.[145] The models also develop or make use of other historical and projected data, including number of customers, weather degree days, population changes, manufacturing activity, and other econometric data.

After reviewing the Company's sales and transportation forecast by customer class against the historical weather-normalized gas deliveries, I determined that the Company has captured the recent historical trend in gas sales and transportation deliveries to most customer classes relatively well, and I do not dispute those forecasts. However, I believe that the Company has underestimated commercial transportation volumes and the related revenues for the projected test year by a significant amount.

**Q. WHAT IS THE BASIS FOR YOUR CONCLUSION THAT COMMERCIAL GAS TRANSPORTATION DELIVERIES ARE UNDERSTATED?**

A. In response to discovery, the Company provided actual weather-normalized gas sales and transportation deliveries along with the related number of customers by customer class for

[144] Exhibit AG-53, column (k) plus Inter-Departmental sales of 114 MMcf and transportation volumes of 45 MMcf from DR AG-C-0310 Attachment 1 and Part III Information Schedule 15.
[145] DR AG-CE-0306.

each year from 2019 to 2024 and for the forecasted years 2025, 2026, and the projected test year. From the data provided by the Company, in Exhibit AG-53, I calculated the average weather-normalized annual gas usage per customer for each of the customer classes. The analysis on lines 11 and 12 of Exhibit AG-53 shows that from 2019 to 2024, the average annual gas usage per commercial transportation customer declined from 9,695.18 Mcf to 9,593.75 Mcf, or an average of 0.2% annually over the five-year period.

For the more recent three years, from the end of 2021 to the end of 2024, the annual rate of decline was 0.5%. In contrast, the Company projected a decline in gas usage of 5.5% in 2025 from actual weather-normalized gas deliveries in 2024 with an additional decline of 0.6% in 2026 for a cumulative decline of 5.9% between 2024 and the end of the projected test year. This large rate of decline over less than a two-year period is excessive and unsupported. Mr. Ahmed's direct testimony is devoid of any explanations as to the reasons for such a decline when other customer classes, including transportation gas deliveries, have considerably lower rates of decline over the 2024 to 2026 period or have increases in sales and transportation deliveries.

Exhibit A-15 (MA-4), Schedule E-10, shows a similar decline in overall transportation gas deliveries between the 2023 historical test year and the projected test year. The decline in transportation deliveries of 1,764 MMcf on line 13, column (e), is primarily attributable to the decline in commercial transportation volumes discussed above. In discovery, the Attorney General asked the Company to explain this unusual decline in forecasted volumes. In response, the Company had no specific or pertinent answer other than to state

that it was mathematical calculation driven by economic indicators and usage patterns in recent history.[146]

However, that explanation does not fit the evidence shown in Exhibit AG-53. The recent usage pattern in the most recent three years shows a decline of only 0.5% for the commercial transport class and an annual increase of 2.6% for the industrial transportation class, which has even larger delivery volumes than the commercial class. Therefore, overall transportation volumes should be increasing and not decreasing. Similarly, the economic indicators apply to both commercial and industrial customers, which also invalidates that explanation.

The logical conclusion that can be drawn from this analysis is that the Company's forecasting model provided a forecast for commercial transportation deliveries that is inaccurate.

**Q. DID YOU CALCULATE REVISED COMMERCIAL TRANSPORTATION VOLUMES AND THE RELATED REVENUE ADJUSTMENT BASED ON YOUR ANALYSIS?**

A. Yes. Exhibit AG-54 show the calculations of the incremental volumes and revenue for the forecasted test year for the commercial transportation customer class. To arrive at the revised volumes, I started with the actual weather-normalized sales per customer for 2024 from Exhibit AG-53 and adjusted those volumes down based on the underlying average

[146] Exhibit AG-55 includes DR AG-CE-0313 and 0746.

annual rate of decline in volume from the three-year period 2021 to 2024. The calculation includes those adjustments for the 10 months ending October 2025 and for the 12 months ending October 2026. The adjusted gas usage per customer for the projected test year was then multiplied by the number of customers forecasted by the Company for the projected test year.

Based on those calculations, I forecasted commercial transportation volumes of 26,373 MMcf for the projected test year, which is an increase of 1,325 MMcf over the Company's forecast. I then allocated the incremental volumes by rate schedule based on the allocation methodology provided by the Company and applied the respective current distribution rates to calculate the incremental revenue.

In total, the incremental forecasted revenue for the projected test year is $1,822,000.

**Q. WHY DID YOU USE THE 2024 AVERAGE USAGE PER CUSTOMER AND THE HISTORICAL THREE-YEAR RATE OF DECLINE IN COMMERCIAL VOLUMES TO FORECAST THE PROJECT TEST YEAR VOLUMES?**

A. The weather-normalized usage per customer for the year 2024 represents the most recent gas usage profile. The three-year rate of volume decline represents a realistic trendline over the most recent three years and normalizes any temporary annual variances in usage volumes. In that regard, it provides a more current and accurate forecast than the Company's forecasting model, which uses stale customer usage data from 11 years ago,

starting in 2013, and which has been tainted by unusual events, such as the Covid pandemic.

**Q. ON PAGE 8 OF HIS DIRECT TESTIMONY, MR. AHMED IMPLIES THAT HIS FORECASTING MODEL IS HIGHLY ACCURATE. HOW DO YOU RESPOND?**

A. In his testimony, Mr. Ahmed states that the mean absolute percentage error (MAPE), also known as the mean absolute percentage deviation, of his forecasting model is 0.6%. While that percentage may seem low, it means that on average the sales forecasted by the model are 2.6 Bcf lower or higher than the actual results. Those 0.6% and 2.6 Bcf deviations were calculated on average over a 7-year period. In the prior rate case No. U-21490, the Company calculated the deviation over a 10-year period with an average percentage of 1.0% and 4 Bcf, which is even a larger volume deviation in the forecasting model. In response to discovery in that case, the Company provided the standard deviation by year and the volume variance. That information shows that in any year the standard deviations can range from nearly zero to 3.5% and the volume variance can range from near zero to 10 Bcf.[147]

As shown in Exhibit AG-54, the transportation volume adjustment I proposed of 1.3 Bcf results in a revenue adjustment of nearly $1.8 million. Therefore, the 2.6 Bcf or 4.0 Bcf standard deviation volume variance that Mr. Ahmed considers highly accurate can still result in millions of dollars of lower or higher forecasted revenue.

[147] U-21490 DR AG-CE-0336.



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**Q. WHAT IS YOUR CONCLUSION AND RECOMMENDATION?**

A. The commercial transportation volumes and the related revenue forecasted by the Company are understated and need to be adjusted. I recommend that the Commission adopt my volume adjustment and increase the revenue forecasted by the Company for the projected test year by $1,822,000.

## X. Operations and Maintenance Expenses

**Q. WHAT ARE YOUR FINDINGS IN ANALYZING THE COMPANY'S LEVEL OF O&M EXPENSES INCLUDED IN THIS RATE CASE?**

A. Exhibit A-13 (HLR-41), Schedule C-5, shows the Company forecasted total O&M expenses of $297.9 million for the projected test year.[148] While this expense level is $23.0 million lower than the historical test year, the 2023 historical expense includes $52.9 million of expenses for the Appliance Service Plan, which the Company has sold. This expense has been excluded from the project test year. The decline in expense also reflects the increase in negative expense for Pension and Other Post Employment Benefits (OPEB) of $15.3 million primarily due to increased stock market returns. After adjusting for these expense items, the decrease in expense for the projected test year is actually an increase of $45.1 million.

[148] See line 34 of Exhibit A-13 (HLR-41), Schedule C-5, excluding LAUF and Company Use Gas.

In my testimony below, I recommend that the Company's forecasted O&M expense should be reduced by ~~$73.3~~$56.4 million. Exhibit AG-56 CONF revised shows a summary of my proposed O&M expense adjustments.

**Q. IN YOUR ANALYSIS, HAVE YOU DETERMINED SPECIFIC AREAS WHERE OTHER O&M EXPENSES SHOULD BE REDUCED?**

A. Yes. I have analyzed O&M expenses by major department or area, and I have identified more appropriate and reasonable expense levels that the Commission should consider.

## A. Inflationary Adjustments to O&M Expenses

**Q. HAVE YOU MADE ANY ADJUSTMENTS TO THE INFLATION AND MERIT INCREASE ADJUSTMENTS TO O&M EXPENSES PROPOSED BY THE COMPANY IN THIS RATE CASE?**

A. In Exhibit A-13, Schedule B-5.1, the Company shows inflation and merit adjustments totaling to $3.7 million from 2024 to the end of the projected test year. The calculation of these inflationary adjustments was based on forecasted CPI rates of 3.2% for 2024, 2.4% for 2025, and 2.5% for 2026. However, these adjustments apply to only a portion of the Company's historical O&M expenses. For other O&M expenses, the Company used inflationary increase and wage increase of 3.5% or higher. The Company's reasoning is that these other costs are increasing at rates higher than the CPI forecasted inflation factors

and should be accorded higher cost increases for 2024 through the end of the projected test year.

Although the assumed rates of increase are not often clearly disclosed and are excessive, in my analysis of the forecasted expenses within certain operating units and cost functions, I proposed specific adjustments to expenses where I found those cost increases excessive and unsupported. However, I recommend that the Commission direct the Company to clearly disclose by operating unit and cost function the forecasted inflationary cost increases it has included in the bridge period and the projected test year for specific expense items if those increases are different than the CPI forecasted inflation rates reported separately.

## B. Gas Engineering and Gas Supply

### 1. System Integrity Expense

**Q. PLEASE DISCUSS THE ADJUSTMENT THAT YOU PROPOSE TO THE FORECASTED O&M EXPENSE FOR SYSTEM INTEGRITY FOR THE PROJECTED TEST YEAR.**

A. On line 5 of page 5 of Exhibit A-81 (KAP-2), the Company shows an increase in O&M expense of $1,513,000 under Other Adjustments. On page 19 of her direct testimony, Ms. Pascarello attributes this and other expenses to the departmental reassessment of work activities with no further details. In discovery, the Attorney General asked the Company to specifically explain the increase of $1.5 million. In response, the Company stated that the $1.5 million does not represent an increase in workload, but instead a reclassification

of existing salaries and expenses. No additional information was provided from where those costs were reclassified, and no showing was made that a comparable decrease in expense was included in the function where those costs previously resided.[149]

In a related discovery request, the Attorney General asked the Company to provide a pro-forma comparison of the 2023 expense to the forecasted expenses for the subsequent years for the departments that were involved in the departmental reorganization to better assess how costs changed or did not change over the three-year period 2023-2026. In response, the Company refused to provide the request information, claiming that it had not prepared such information, and it would be difficult and burdensome to prepare it.[150]

In prior rate cases, the Commission ruled that the Company has the responsibility to provide sufficient and comparable historical information to explain and shows cost changes resulting from departmental reorganizations. In this case, the Company failed to do so. Without comparable and sufficient historical information clearly disclosed, it is not possible to trace and validate the historical costs and ensure they were removed and offset the increase in the new function or area where they now reside for the projected test year. Therefore, lacking this information, I recommend that the Commission remove the $1,513,000 expense from the Company's forecasted O&M expense for the projected test year.

[149] Exhibit AG-57 includes DR AG-CE-0381.
[150] Id. includes DR AG-CE-0374.

**2. Quality Lean Office Expense**

**Q. PLEASE DISCUSS THE ADJUSTMENT THAT YOU PROPOSE TO THE FORECASTED O&M EXPENSE FOR THE QUALITY LEAN OFFICE EXPENSE FOR THE PROJECTED TEST YEAR.**

A. On line 1 of page 5 of Exhibit A-81 (KAP-2), the Company shows forecasted O&M expenses of $3,152,000 for Gas Project Management and Quality Lean Office with an increase in expense of $1,843,000 from the 2023 historical level shown under Other Adjustments. On page 12 of her direct testimony, Ms. Pascarello discusses the functions within this department. With regard to the Quality Lean Office, she states that the key responsibilities for this function are to develop and implement policies, process, and procedures, among other tasks, to improve business efficiencies, reduce waste and errors, enhance customer satisfaction and create company-wide value streams. Ms. Pascarello also stated that in August 2024 the Company integrated the Enterprise Corrective Action Program with the Quality Lean office.

In discovery, the Attorney General asked the Company to provide the number of employees working in the Quality Lean Office, the O&M expense incurred by the department, and the list of major accomplishments achieved during the 2021-2024 period and the cost savings or financial benefits realized. In response, the Company identified 24 employees assigned to the gas side of the business within the total Quality Lean Office and an additional 32 employees assigned to the electric side of the company. The Company

also reported that the forecasted O&M expense for the gas portion of the department for the projected test year is $1,259,000.[151]

However, in response to the request for accomplishments and cost savings or financial benefits, the Company could not provide any pertinent information. Instead, it provided a general statement that the Quality Lean Office itself does not achieve improvements but provides support to other Company personnel.[152] That response does not provide any evidence that the cost paid by customers for this function is having a significant beneficial impact, reducing costs or achieving other financial benefits. Without that information, it is not possible to assess the value created by the Quality Lean Office.

Therefore, the forecasted expense is not justified and should be disallowed. I recommend that the Commission remove the $1,259,000 of O&M expense from this rate case.

**3. Advanced Methane Detection Expense**

**Q. PLEASE DISCUSS THE ADJUSTMENT THAT YOU PROPOSE TO THE FORECASTED O&M EXPENSE FOR THE ADVANCED METHANE DETECTION EXPENSE FOR THE PROJECTED TEST YEAR.**

A. In the Capital Expenditures section of my testimony, I proposed the removal of capital expenditures for the AMD program. Related to the capital expenditures, the Company forecasted $1,969,000 of O&M expense to implement the AMD program.[153] Consistent

[151] Id. includes DR AG-CE-0373 and 0378.
[152] Id.
[153] Id. includes DR AG-CE-0422 with attachments.

with my recommendation in the Capital Expenditures section, I recommend that the Commission also remove the O&M expense of $1,969,000 from this rate case.

## C. Operations, Maintenance & Metering

### 1. Leak Repair & Survey Expense

**Q. PLEASE DISCUSS THE ADJUSTMENT THAT YOU PROPOSE TO THE FORECASTED O&M EXPENSE FOR LEAK REPAIR AND SURVEY FOR THE PROJECTED TEST YEAR.**

A. On line 7 of page 1 of Exhibit A-87 (JPP-2), the Company shows forecasted O&M expenses of $17,680,000 for Leak Repair & Survey, which is an increase in expense of $2,814,000 from the 2023 historical level. On pages 34-40, Company witness James Pnacek discusses the major components of the increase in expense. Although some of the increase in the forecasted expense is meant to address a plan to reduce the backlog in outstanding gas leaks, the Company also included $1,300,000 of expense pertaining to the anticipated implementation of the new LDAR rule proposed by PHMSA. As discussed earlier under the Capital Expenditures section of my testimony, the proposed rule has been placed on hold, and it is not known at this time if and when it may be issued.

Therefore, the forecasted expense should not be incurred in the projected test year. I recommend that the Commission remove the $1,300,000 for the Company's forecasted O&M expense.

## 2. Gas Line Staking & Locating Expense

**Q. PLEASE BRIEFLY DESCRIBE THE COMPANY'S PROPOSED CHANGES TO THE GAS LINE STAKING AND LOCATING PROGRAM AND THE IMPACT ON FORECASTED O&M EXPENSE FOR THE PROJECTED TEST YEAR.**

A. On line 9 of page 1 of Exhibit A-87 (JPP-2), the Company shows Staking expense increasing from $12.4 million in 2023 to $24.4 million for the projected test year for an increase of $12.0 million or 97%. Beginning on page 43 of his direct testimony, Mr. Pnacek discusses the Staking and Locating program and on page 44 identifies the major drivers for the increase in expense. The largest increase at $15.1 million pertains to the expansion of the Gas Only locating program to other areas of the Company service area outside of the Oakland and Kent counties. Costs are also increasing in Oakland and Kent counties by $4.0 million and in other areas of the program by $1.0 million. This increases are partially reduced by terminating the shared staking and locating contracts.

Where typically gas, electric, water, and cable companies share the cost of locating underground facilities when Miss Dig is requested to locate underground facilities by customers, contractors, and other parties, in 2023, the Company began a program of staking only its own gas and electric facilities in Oakland and Kent counties and now wants to expand the program to the rest of the state.

**Q. WHAT IS YOUR ASSESSMENT OF THE COMPANY'S PROPOSED CHANGES TO THE GAS LINE STAKING AND LOCATING PROGRAM?**

A. The change to a dedicated model emanated from internal and external problems that the Company had in managing its staking and locating program in recent years primarily in Oakland and Kent counties. The Company-only dedicated staking and locating program started in Oakland County and was an experimental program to establish whether the incremental benefits justified the incremental cost of a dedicated program. That evaluation was never thoroughly presented in prior rate cases or this rate case.

On page 51 of his direct testimony, Mr. Pnacek tries to justify the expansion of the dedicated Company-only program by pointing to less than two years of data from Oakland and Kent counties. Throwing more resources at the problem at twice to three times the previous costs may show better statistics but does not mean it is the optimal approach to take. There has been no evidence presented in this rate case or previous rate cases that the Company attempted to work with the shared model staking and locating contractors to resolve whatever problems with performance existed and in turn minimize the cost of staking and location.

In this rate case, the Company proposes to expand the dedicated Company-only model to other counties in Michigan at an additional cost of $12 million without providing any evidence that a serious problem with staking and locating exists in those counties that cannot be resolved in other ways. This is not a prudent way to spend money that the Company seeks to recover from customers.

On page 52 of his testimony, Mr. Pnacek states that based on recent bids received from contractors the cost per unit is lower for the dedicated model than the shared model. This

is counter to the historical evidence presented by the Company. As shown in Table 29 on page 44 of Mr. Pnacek's direct testimony, the Company forecasted that the cost to expand the dedicated model to areas outside of Oakland and Kent will be $15.1 million while eliminating only $7.9 million in costs from the shared model. The bidding process that the Company went through in 2024 cannot be relied on. The Company has made it clear publicly in testimony in at least the last two rate cases that it prefers to move to a dedicated model and contractors have understood that preference. Contractors also prefer a dedicated model because it increases their revenue by expanding their services. Their bids likely reflect that common desire to move to a dedicated model and should not be relied on by the Commission in reaching a decision in this matter.

**Q. WHAT IS YOUR CONCLUSION AND RECOMMENDATION?**

A. The Company did not provide any compelling and convincing evidence that a problem exists in other counties outside of Michigan that cannot be resolved within the shared staking and locating model. The shift to the Company-only dedicated model is unsupported and very expensive. The bidding process showing of a lower cost for the dedicated model against the shared model is counter to recent historical evidence and cannot be relied on.

Therefore, I recommend that the Commission remove the incremental O&M expense of $11,184,000 included by the Company in the projected test year.[154]

**3. EIRP Training Expense**

**Q. PLEASE DISCUSS THE ADJUSTMENT THAT YOU PROPOSE TO THE FORECASTED O&M EXPENSE FOR EIRP TRAINING FOR THE PROJECTED TEST YEAR.**

A. On line 9 of page 1 of Exhibit A-88 (JPP-3), the Company shows forecasted O&M expenses of $5,048,000 for the EIRP, which is an increase in expense of $1,700,000 from the 2023 historical level. On pages 85-88 of his direct testimony, Company witness James Pnacek discusses the major components of the increase in expense. Table 62 shows that $1,656,000 of the increase pertains to EIRP Labor OM&C Training. Mr. Pnacek's direct testimony does not explain this increase in expense.

In discovery, the Attorney General asked the Company to expand the table on page 86 of Mr. Pnacek's testimony and provide the historical expenses for 2022-2024. The Company was also asked to explain the reasons for the increase of approximately $1.6 million. In response, the Company stated that the EIRP workforce continues to grow requiring additional training expense from 2023 to the projected test year.[155]

[154] James Pnacek direct testimony, Table 29: 2023: Shared Services of $7,865,196 + Dedicated Oakland & Kent $2,766,691 – PTY: Dedicated Services Oakland & Kent of $6,703,509 – Dedicated Other Areas of $15,112,608 = $11,184,000 rounded.
[155] Exhibit AG-58 includes DR AG-CE-561 Revised with attachment.

However, the actual expense for training incurred in 2023 declined by approximately $900,000 from 2022 and declined further in 2024 by an additional $300,000 to $1.8 million.[156] The $3.8 million forecast for the projected test year does not follow the trajectory of an expanding EIRP in recent years and is not adequately supported. The EIRP is a mature program and employees working on the program should already be knowledgeable and trained on how to install pipe, services, and other parts and equipment. No evidence of a high turnover in employees has been presented to justify the training of a larger number of employees or contractors. Furthermore, as I proposed in the Capital Expenditures section of my testimony, the EIRP should be scaled back beginning with the projected test year to stay within a reasonable cost budget. This reduction in spending will require fewer resources,

Therefore, I recommend that the Commission remove the increase of $1,656,000 from the Company's forecasted O&M expense.

## D. Transmission Expense

### 1. MAOP Related Expense

**Q. PLEASE DISCUSS THE ADJUSTMENTS THAT YOU PROPOSE TO FORECASTED TRANSMISSION O&M EXPENSE FOR THE PROJECTED TEST YEAR PERTAINING TO MAOP PROJECTS.**

[156] Id.

A. On page 29 of his direct testimony, Mr. Griffin discusses the O&M expense that the Company plans to incur to identify deficiencies with traceable, verifiable, and complete records to reestablish the MAOP for transmission, storage, and distribution pipelines. Page 16 of Ms. Pascarello's also briefly discusses this matter. In response to discovery, the Company confirmed that for the projected test year, it forecasted $1,122,000 to perform the MAOP records review.[157]

As discussed, in the Capital Expenditures section of my testimony regarding MAOP projects, the Commission ruled in a previous rate case that recovery of only 50% of this expense should be allowed and the remaining 50% should be disallowed. Therefore, I recommend that $561,000 of expense be removed from the Company's forecasted O&M expense.

**2. Corrosion Control Expense**

**Q. PLEASE DISCUSS THE ADJUSTMENTS THAT YOU PROPOSE TO FORECASTED TRANSMISSION O&M EXPENSE FOR THE PROJECTED TEST YEAR FOR CORROSION CONTROL.**

A. On line 2 of page 2 of Exhibit A-58 (MPG-1), the Company shows an increase of $1,263,000 in Corrosion Control under Other Adjustments from the 2023 historical expense to the projected test year. In discovery, the Attorney General asked the Company to explain this increase in expense and provide pertinent support for it. In response, the

[157] Exhibit AG-59 incudes DR AG-CE-0380 and 0778.

Company stated that the increase pertained to changes in the PHMSA regulations to prevent atmospheric corrosion and recoat pipelines and related facilities. The discovery response also provided a table showing historical and forecasted component expenses from 2023 to the projected test year. No work units or quantity of activities were provided to support the annual expenses.[158]

In a subsequent discovery response, the Company elaborated that the atmospheric corrosion work being done is basically repainting sections of pipelines and related facilities both above ground and below ground. Painting of pipelines and facilities is not a new requirement and any expansion of requirements under PHMSA regulations also existed in 2023 and 2024 when costs were less than half the amount forecasted for the projected test year.

The increase in expense for the projected test year is not supported by any increased work units or work activities and the PHMSA reference by itself does not justify the increase in expense. To arrive at a reasonable expense forecast, I applied the forecasted CPI inflation factors to the 2023 actual expense and calculated a forecasted expense of $1,024,000. This amount is $1,186,000 lower than the Company's forecasted expense of $2,210,000. Therefore, I recommend that the Commission remove $1,186,000 in expense from the Company's forecasted O&M expense for the projected test year.

[158] Id. includes DR AG-CE-0338.

### 3. Riverside Storage Field Expense

**Q. PLEASE DISCUSS YOUR PROPOSED ADJUSTMENT TO THE COMPANY'S FORECASTED AMORTIZATION EXPENSE FOR THE RIVERSIDE STORAGE FIELD LOSS.**

A. As discussed in the Working Capital section of my testimony, the Company had recorded a loss to a deferred regulatory asset account on the expectation that it would sell the field to a prospective buyer. The Company amortized and recorded one-third of the loss to expense in this rate case. With the sale no longer proceeding, the amortization expense of $2,959,000 should be removed from the expense. I recommend that the Commission remove this amount from the Company's forecasted expense from the projected test year.

## E. Customer Service Expense

### 1. Analytics & Outreach Expense

**Q. PLEASE DISCUSS THE ADJUSTMENTS THAT YOU PROPOSE TO FORECASTED CUSTOMER SERVICE O&M EXPENSE FOR THE PROJECTED TEST YEAR FOR ANALYTICS AND OUTREACH.**

A. On line 1 of page 3 of Exhibit A-37 (URB-2), the Company shows $2,325,000 of O&M expense for the Analytics and Outreach function. Witness Jessica Byrom's direct testimony is devoid of any testimony addressing this expense function. In discovery, the Attorney General asked the Company to provide the historical and forecasted number of employees and contractors, the number of work units or work activities, and the tasks and

outcomes accomplished in the past two years and planned for 2025 and 2026 in this department or function.

In response, the Company identified 58 employees and 14 contractors working in this area for total of 72 people in 2024, and that number increases to 74 for the projected test year. For work units, the Company identified 17 customer interactions in 2022, and that number fell to 7 interactions in 2024 and stays at 7 for the projected test year. From the response, it is not clear what customer interactions entail, why there are so few, and why they decline from 2022 and stay the same between 2024 and the projected test year when the number of employees and contractors in this function increases.[159]

Regarding tasks performed and accomplishments achieved, the information provided is very general about improving the customer experience, whatever that means, and does not make a compelling case that significant value is being generated for the $2.3 million expense.[160] The evidence is inadequate, and the expense remains unsupported. Therefore, I recommend that the Commission disallow recovery of the $2,325,000 from the Company's forecasted O&M expense for the projected test year.

[159] Exhibit AG-60 includes DR AG-CE-0659 with attachments.
[160] Id.



VERITEXT LEGAL SOLUTIONS

**2. Digital Customer Operations Expense**

**Q. PLEASE DISCUSS THE ADJUSTMENTS THAT YOU PROPOSE TO FORECASTED CUSTOMER SERVICE O&M EXPENSE FOR THE PROJECTED TEST YEAR FOR DIGITAL CUSTOMER OPERATIONS.**

A. On line 5 of page 3 of Exhibit A-37 (URB-2), the Company shows $1,072,000 of O&M expense for the Digital Customer Operations. Witness Jessica Byrom's direct testimony is devoid of any testimony addressing this expense item. In discovery, the Attorney General asked the Company to provide the historical and forecasted number of employees and contractors, the number of work units or work activities, and the tasks and outcomes accomplished in the past two years and planned for 2025 and 2026 in this department or function.

In response, the Company identified 23 employees and 5 contractors working in this area for total of 28 people in 2024, and that number increases to 29 for the projected test year. For work units, the Company identified 4 customer interactions in 2022, and that number fell to 3 in 2024 and stays at 3 for the projected test year. From the response, it is again not clear what customer interactions entail, why there are so few, and why they decline from 2022 to the projected test year.[161]

Regarding the task performed and accomplishments achieved, the information identified the major tasks performed. However, it is not clear why most of the system functions

[161] Exhibit AG-60 includes DR AG-CE-0659 with attachments.

already developed would require repeat work using the same number of employees and contractors every year. The general description of accomplishments does not make a compelling case that significant value is being generated. There is insufficient support to justify the number of resources assigned to this function. The evidence is inadequate, and the expense level remains unsupported. Therefore, I recommend that the Commission disallow recovery of at least 50% of the $1,072,000 or $536,000 from the Company's forecasted O&M expense for the projected test year.

## F. Company Use & LAUF Gas Expense

**Q.** ~~**PLEASE DISCUSS THE ADJUSTMENTS YOU PROPOSE TO COMPANY USE GAS AND LAUF GAS FOR THE PROJECTED TEST YEAR.**~~

~~A. Regarding Company Use Gas expense, in Exhibit A-75 (TKJ-4) the Company calculated the projected test year expense of $5,502,000 based on volumes determined in WP TKJ-15. In response to discovery, the Company reported that the volumes flowing from WP TKJ-14 into WP TKJ-15 were incorrect as filed. The Company provided revised credit volumes received from Act 9 transportation customers for the historical 5-year period, which average to 2,089 MMcf.[162] The forecasted volumes for the projected test year are set based on the historical 5-year average. Using the revised volumes in the Excel financial model for Exhibit A-75, I recalculated the forecasted expense for Company Use Gas at~~

[162] ~~Exhibit AG-61 includes DR AG-CE-0516 and Attachment 1 and 2.~~

~~$3,702,000.[163] This amount is $1,800,000 lower than the amount calculated by the Company.~~

~~The revised transportation volumes also affected the calculation of the LAUF Gas expense due to the partial transportation offset included in the calculation of this expense. The result is a revised expense for LAUF Gas of $8,551,000.[164] This amount is $4,158,000 lower than the $12,709,000 calculated by the Company.~~

~~Therefore, I recommend that the Commission remove the $1,800,000 and $4,158,000 from the Company filed O&M expense for Company Use and LAUF Gas, respectively, for the projected test year.~~

**Q. DO YOU PROPOSE ANY ~~OTHER~~ ADJUSTMENTS TO LAUF GAS EXPENSE?**

A. Yes. On pages 24 and 25, Mr. Joyce discusses several initiatives undertaken by the Company to reduce LAUF Gas, including the replacement of leaky pipes and its Net Zero Methane Emission goal. Beginning on page 77 of the most recent Natural Gas Delivery Plan, filed in this rate case as Exhibit A-42 (NPD-1), the Company outlined its Gas System Decarbonization plan and states that by 2030 it will reduce methane emissions by 80% from the 2023 level of 13,811 metric tons.

~~[163] Exhibit AG-62.~~
~~[164] Id.~~

The 80% reduction translates into 11,049 fewer metric tons of methane emissions, which is equivalent to 545,379 Mcf less natural gas in LAUF gas.[165] For the seven-year period from 2023 to 2030, the reduction is 77,911 Mcf per year. Over the 34 months from January 2024 to October 2026, the cumulative reduction is 220,748 Mcf.[166] This volume multiplied by the average cost of gas rate of $3.296 shown in Exhibit A-75 results in a LAUF Gas expense reduction of $728,000.

The Company appears committed to achieving the 80% target reduction and is planning to spend large sums in capital investments and O&M expense to achieve it. Within the context of a projected test year rate case, it is reasonable to expect that the Company will achieve its overall goal between 2023 and the projected test. Hence, the Company should be held accountable for the planned result. Therefore, I recommend that the Commission remove $728,000 of LAUF Gas expense from the Company's projected O&M expense.

## G. Information Technology Expense

### 1. IT Investment Expense

**Q. PLEASE DISCUSS YOUR PROPOSED ADJUSTMENT TO IT INVESTMENT O&M EXPENSE.**

A. On line 3 of page 1 of Exhibit A-19 (SHB-3), the Company forecasted IT Investment O&M expense of $16,814,000 for the projected test year. This level of expense is an increase of

[165] One Metric Ton = 49.36 Mcf.
[166] 77,911 Mcf ÷ 12 x 34 months.

$12,938,000 over the 2023 historical expense of $3,876,000. [Begin Conf] [redacted] [End Conf] of the increase pertains to the proposed SAP S/4 HANA ERP project.[167]

As I stated in the Capital Expenditures section of my testimony, the proposed ERP project is still premature and inadequately justified to include in rate base and all related capital expenditures should be removed from this rate case. Similarly, the Commission should remove the [Begin Conf] [redacted] [End Conf] in O&M expense from this rate case.

In a similar vein, the recommendation by Company witness Heidi Myers on page 15 of her testimony to establish deferred regulatory asset accounts to record the IT Investment O&M costs and the cloud implementation costs for development of the SAP/ERP projects should be denied at this time as premature and unnecessary.

**2. Cloud Computing Expense**

**Q. PLEASE DISCUSS YOUR PROPOSED ADJUSTMENT TO IT INVESTMENT O&M EXPENSE.**

A. As discussed in the Working Capital section of my testimony, the Company made an error in calculating the amortization expense for cloud computing fees and costs that have been deferred. The Company rate case filing included $17,351,545 of expense. The correct amortization expense should be $11,874,017.[168] Therefore, the difference of $5,478,000

[167] Stacy Baker confidential direct testimony at page 104.
[168] Exhibit AG-38.

should be removed from the expense forecasted by the Company for the projected test year. I recommend that the Commission remove this amount.

### 3. IT Projects Disallowed - Expense

**Q. PLEASE DISCUSS YOUR PROPOSED ADJUSTMENT TO IT INVESTMENT O&M EXPENSE PERTAINING TO IT CAPITAL PROJECTS YOU HAVE PROPOSED BE DISALLOWED.**

A. As discussed in the Capital Expenditures section of my testimony, the O&M expense for the following three capital IT projects should be disallowed in addition to the capital costs. The three projects and related O&M expense for the projected test year are:

1. The Utility Network: $517,000
2. Data Center Migration: $716,000
3. Gas Tracking and Traceability: $509,000

The total expense for the three projects is $1,742,000. I recommend that the Commission remove this amount from the Company's forecasted OM expense.

## H. Voluntary Separation Program Expense Savings

**Q. PLEASE DISCUSS YOUR PROPOSED O&M EXPENSE ADJUSTMENTS FOR THE VOLUNTARY SEPARATION PROGRAM.**

A. In 2023, the Company began a Voluntary Separation Program (VSP) to downsize its workforce. The downsizing program continued into 2024 and accumulated significant cost savings. In discovery, the Attorney General asked the Company to provide the

amount of cost savings since the beginning of the program and through the projected test year. The Company was also asked to provide the underlying calculations of the costs savings and a reference in which exhibit and line number the cost savings were reflected with supporting evidence through workpapers and other schedule that would show the cost savings were included in the forecasted expense of each department or area for the projected test year.

In response, the Company identified $7,989,000 of cost savings for the projected test year.[169] However, the Company did not provide the underlying calculations showing how the cost savings were calculated. No labor hours, labor rates, other cost savings, and reductions in employee benefits were disclosed. The Company also did not provide any workpapers or supporting schedules that would show the cost savings were actually included in the forecasted periods and the projected test year in each exhibit for each of the affected departments. The result is that the cost savings cannot be traced back to the various departments and the referenced exhibit lines and validated. Therefore, there is no certainty that the cost savings were incorporated in the projected test year forecasted O&M expense of each of the affected departments.

I recommend that the Commission remove the entire $7,989,000 of VSP cost savings from the Company's forecasted O&M expense for the projected test year to ensure that the cost savings are appropriately reflected in rates in this rate case

[169] Exhibit AG-63 includes DR AG-CE-0372 with ATT_1.

## I. ~~Corporate O&M Expense~~

~~**Q. PLEASE DISCUSS YOUR PROPOSED ADJUSTMENT TO CORPORATE O&M EXPENSE.**~~

~~A. On line 6 of Exhibit A-44 (MJF-2), the Company shows Corporate General Activities cost and credits from 2023 through the projected test year. The amount under the Labor column for 2023 of $7,428,000 is unusual and excessive. In discovery, the Attorney General asked the Company to expand Exhibit A-44 and provide similar information for actual years 2021, 2022, and 2024. The additional historical information shows that the Labor amount for General Activities in 2021 was a negative amount of $12.2 million. The 2022 amount was also negative at $1.6 million, and 2024 has a negative amount of $2,770,000.[170]~~

~~In discovery, the Attorney General asked the Company to provide the components of the $7,428,000 expense and a thorough explanation of the unusual positive amount in 2023 when the other years show negative amounts for Labor in this General Activities category. However, the requested cost components were not provided, and the explanations were not directly pertinent to the amount requested to be explained, and were inadequate.[171] The $7,428,000 labor amount from 2023 remains unexplained and unsupported by the Company~~

[170] ~~Exhibit AG-64 includes DR-AG-CE-0297 with Attachment.~~
[171] ~~Id. includes DR-AG-CE-0741.~~

~~To develop a reasonable forecast for General Activities, I used the negative amount of $2,770,000 from 2024, as the most recent basis to calculate the forecasted amount for the projected test year. After adjusting that amount for inflation, I arrived at the projected test year negative amount of $2,896,000.[172] After including the inflation adjustments calculated by the Company from 2023 to the projected test year, the $7,428,000 increased to $8,014,000 at the end of the projected test year.[173] The difference between the negative $2,896,000 and the $8,014,000 is $10,910,000 ( $2,896,000 – 8,014,00).~~

~~I recommend that the Commission remove the $10,910,000 from the Company's projected test year O&M expense for the Corporate General Activities.~~

## J. Active Health Care Expenses

**Q. PLEASE DISCUSS THE COMPANY'S PROJECTED EXPENSE FOR ACTIVE HEALTH CARE, LIFE INSURANCE AND LONG-TERM DISABILITY.**

A. Line 4 of Exhibit A-64 (KKG-1) shows actual health care, life insurance and long-term disability (Health Care & Other) expense of $19,765,000 for the projected test year, which is an increase of approximately $1.4 million or 10.6% over the 2023 historical expense. To arrive at the projected test year expense, the Company applied the forecasted CPI inflation rates of 3.2%, 2.4% and 2.5% from 2024 through the 10 months of 2026.

~~[172] $2,770,000 x 1.024 x 1.021 = $2,896,000.~~
~~[173] $7,428,000 + $238,000 for 2024 + $184,000 for 2025 – $164,000 for the 10 months in 2026 = $8,014,000.~~

In discovery, the Attorney General asked the Company to identify the cost savings of various initiatives taken in recent years and anticipated to be taken in 2025 and 2026 to reduce health care costs. In response, the Company identified cumulative cost savings by year from 2023 to 2026. For 2023, the Company realized $3,763,000 in cost savings. By 2025 and 2026, the Company expects to achieve cost savings of between $6,378,000 and $7,211,000.[174] The prorated amount for the projected test year based on those amounts is $6,517,000. This amount is $2,754,000 above the $3,763,000 realized in 2023.

**Q. WHAT IS YOUR PROPOSED ADJUSTMENT TO HEALTH CARE EXPENSE FOR THE PROJECTED TEST YEAR?**

A. I recommend that the Commission reduce the Company's Active Health Care expense for the projected test year by the estimated cost savings of $2,754,000.

## K. Incentive Compensation Expense

Through the testimony of witnesses Amy Conrad and Ashley Meschke, the Company proposes to recover in rates $1,546,000 of short-term incentive compensation.[175]

In the following pages of my testimony, I will analyze the Company proposal to include in rates the cost of incentive compensation and the alleged benefits to customers provided in the testimony of Ms. Meschke. Over the past few years, the Company has made several changes to the incentive plan that have made it easier for the Company to payout incentive

[174] Exhibit AG-65 includes DR AG-CE-0686.
[175] Exhibit A-41 (AMC-3).

compensation. For example, the operating performance measures that drive the short-term incentive payouts under the plan were revamped in recent years. Beginning in 2022, the ability to trigger a payout has been modified to make it much easier for employees to receive incentive compensation payments. I will discuss these changes in more detail later in my testimony.

**Q. PLEASE PROVIDE A BRIEF SUMMARY OF THE COMPANY'S SHORT-TERM INCENTIVE COMPENSATION PLAN.**

A. The Company has a short-term incentive compensation plan for officers and a slightly different plan for non-officer employees. The Company refers to each of these plans as the Employee Incentive Compensation Plan (EICP).

The major components of the EICP for non-officer employees are shown in Exhibit A-39 (AMC-1). Fifty percent (50%) of the target award in 2023 was based on achieving 6 performance measures related to employee safety, employee satisfaction surveys, customer experience surveys, electric reliability, waste elimination and methane emission reduction.

This 50/50 combination of operating and financial measures started in 2012. In 2010 and 2011, the calculation of the non-officer EICP was based solely on achieving operating performance measures. The requirement to achieve 100% payout of target was also stricter with accomplishment of 9 measures out of 11 needed. The Company then adjusted this percentage based on the percent payout of the officers' EICP. Over the last seven years,

non-officer employees have received incentive payouts as a percentage of target of 123% in 2018, 111% in 2019, 139% in 2020, 77% in 2021, 160% in 2022, 140% in 2023, and 136% in 2024.[176] The only year in the past fourteen years where a bonus payout was not made to non-officer employees was in 2011 when only 6 of the 11 operating measures were achieved. These consistent payouts indicate that incentive compensation is not at-risk compensation based on achieving superior performance, but it simply supplements base pay.

For the officers' EICP, the target payout has been based almost entirely on earnings per share and operating cash flow. However, more recently, 70% of the target payout is from achieving the CMS Energy earnings per share goal and 30% from achieving similar operating performance measures of non-officer employees.

**Q. WHAT IS YOUR OVERALL ASSESSMENT OF BOTH THE OFFICER AND NON-OFFICER EICP?**

A. Generally, the Company's short-term incentive plans are too heavily weighted toward financial measures that mostly benefit shareholders and not customers.

For the 2023 plan cycle, half of the non-officer employee EICP payouts and 70% of the Officer EICP payouts were dependent upon the financial metrics. As such, the officer group that sets the direction of the Company is still far too focused on financial results. Customers do not directly benefit from shareholders achieving a higher return on their

[176] DR AG-CE-00672 with attachments and U-21490 DR AG-CE-165 with attachment.

investment. Although the Company has argued in the past that happy investors will be more attracted to the Company debt and common stock issues and therefore provide a lower cost of capital, it has not offered direct proof to support this argument. The argument is particularly hollow since the Company has not issued any significant common stock in more than five years. Later in my testimony, I will discuss in more detail the customer benefits put forth by Ms. Meschke.

**Q. DO YOU SEE ANY OTHER PROBLEMS WITH THE MEASURES INCLUDED IN THE EICP?**

A. Yes. In the past, the Company had to achieve at least a minimum number of operating metrics to trigger an incentive payout. Although, the number of operating metrics to be achieved was relatively low to demonstrate exceptional performance even that minimal requirement has now been dropped. Therefore, even mediocre performance will be rewarded if only a single metric is achieved. This is a very generous incentive plan that is not directly connected to achieving superior customer benefits before making threshold incentive payouts.

Additionally, the fact that the performance measures use CMS Energy financial information and comingle electric and gas business measures is a concern. Although the Company is a combined gas and electric utility and makes up 95% of CMS Energy, appropriate cost segregation is required to avoid having gas customers subsidize other businesses, particularly non-utility operations.

Lastly, the Company has stated that it continues to pay salary increases each year of approximately 3.5%.

**Q. PLEASE BRIEFLY SUMMARIZE AND PROVIDE YOUR ASSESSMENT OF THE CUSTOMER BENEFITS PRESENTED BY THE COMPANY TO JUSTIFY RECOVERY OF INCENTIVE COMPENSATION COSTS.**

A. In her testimony, Ms. Meschke attempts to quantify certain benefits related to the operating performance measures that are part of the EICP. In Exhibit A-96 (AEM-2), Ms. Meschke shows the number of Safety Incidents, which were 102 in 2020 and 125 in 2023. The actual trend of safety incidents has been upwards. To calculate cost savings, the Company assumed it would be able to reduce the number of incidents to 81 in 2024 and based the calculation on that lower number. However, this is wishful thinking and not actual cost savings achieved. With higher safety incidents in 2023 than in 2020, costs have increased and not decreased. The exhibit also shows that the Company's Workers Compensation and other related costs have been erratic from 2020 to 2023 with no consistent downward trends to create cost savings. Clearly, these results do not show superior performance or an improving trend.

In Exhibit A-97 (RMS-3), Ms. Meschke shows the Company's SAIDI Index results as a measure of Electric Reliability. Instead of using actual SAIDI results for the past year to show a trend, she uses a four-year average from 2020 to 2023 and compares that average to a 2024 goal to calculated potential savings instead of actual savings. This approach of

estimating potential cost savings instead of realized actual savings is an attempt to show cost savings where none have existed.

Ms. Meschke also calculates certain savings related to the Company's Culture Index based on purported cost savings from lower employee turnover. However, Exhibit A-98 shows that employee turnover was 2.7% in 2023 compared to 1.1% in 2020. Clearly, this is not an improving trend. To try and show some costs savings, the Company makes a comparison to other utilities. However, there is a clear mismatch between the employee satisfaction measures which are solely based on internal company surveys and cost savings calculated based on peer company turnover rates.

In summary, the cost savings calculated by Ms. Meschke are inconsistent with recent trends in performance, aspirational, and not based on actual achievements. They do not justify the $1.5 million of incentive compensation that the Company seeks to recover in this rate case.

**Q. BASED ON YOUR REVIEW OF RESULTS DURING THE PAST FIVE YEARS, HAS THE COMPANY ACHIEVED THE TARGET LEVEL OF PERFORMANCE FOR THE OPERATING MEASURES DURING THOSE YEARS?**

A. No. In discovery, the Attorney General asked the Company to provide the target operating measures, and the actual performance achieved for each year from 2020 to 2024. The information provided by the Company shows that in 2020 the Company only met 7 of the 9 operating performance measures at 100% of target or higher for an average achievement

rate 78% of target. In 2021, only 6 of 9 were met at least at 100% for a 67% achievement rate. In 2022, 4 of the 6 operating measures were achieved at least at 100% of target for a 67% achievement rate. In 2023, only 3 of the 6 operating measures were met at least at 100% for a 50% achievement rate and in 2024 only 4 of the 6 measures were met at 100% of target for a 67% achievement rate. The average achievement rate for the past five years was 66%.[177]

In forecasting the amount of EICP expense of $1,546,000 included in the forecasted test year, the Company assumed that all operating measures would be achieved at least at 100% of target for both the officer and non-officer EICP. The results of the last five years do not support this expected performance level. Customers should not pay for expected performance that does not materialize. Therefore, recovery of incentive compensation at less than 100% of target is warranted. Using the 66% average performance achievement rate, the most that the Company should be allowed to recover in this rate case is $1,020,000 ($1,546,000 x 66%). The remaining amount of $526,000 should be disallowed.

**Q. WHAT CONCLUSIONS AND RECOMMENDATIONS HAVE YOU REACHED WITH REGARD TO RECOVERY OF INCENTIVE COMPENSATION COSTS IN RATES?**

A. As discussed above, the focus of the short-term incentive compensation plans is overwhelmingly directed at creating shareholder value, not customer benefits, and the

[177] Exhibit AG-66includes DR AG-CE-0672 with attachments and Part III Item 86 Information.

officer group that directs the day-to-day operations is only minimally incentivized to meet operational goals. Certain design flaws with the EICP tend to reward mediocre performance and diminish any real customer benefits. Incentive compensation should be paid for exceptional performance, at least to pass the test of cost recovery in rates. Performance that is ordinary and achieves basic goals and efficient operations is paid for in base salaries.

Both management and other employees have received large annual merit salary increases since at least 2009. The Company argues that it must pay a competitive compensation package to retain talented management and employees. Although that may be the case, it does not mean that customers should pay for all or most of that expense. Shareholders also significantly benefit from talented management, perhaps even more so than customers. Customers are paying for higher base pay each year. Shareholders can share the burden by paying for the incentive compensation that disproportionally favors their interests.

The Company's proposed incentive compensation expense of $1,546,000 for the projected test year assumes that the Company will achieve target performance for all its goals. There is no track record that supports that conclusion. It is probable that the Company may fall short of achieving 100% of the performance measures in the projected test year. Although I do not believe the Company has made a compelling case to justify recovery of any amount of incentive compensation and therefore no incentive compensation should be included in rates.

In recent rate cases the Commission has approved a portion of incentive compensation pertaining to operating measures and if it decides to do so in this case, I recommend that the Commission approve at most recovery of the $1,020,000 incentive compensation amount I calculated above based on the Company achieving just 66% of the operating performance measures. Therefore, the Commission should disallow at least the remaining amount of $526,000 if not the entire amount of $1,546,000 from the Company's forecasted O&M expense for the projected test year.

## L. O&M Adjustments - Summary

**Q. PLEASE SUMMARIZE YOUR RECOMMENDED ADJUSTMENTS TO O&M EXPENSE.**

A. Operations and maintenance expenses represent a large part of the Company's cost structure. My analysis of the expense level proposed by the Company has shown that in the following areas these expenses are excessive or not needed and should be removed.

| Summary of O&M Expense Reductions<br>Revised | Amount<br>($ Millions) |
|---|---|
| Gas Engineering | $ 4.7 |
| Gas Distribution Operations | 14.1 |
| Gas Transmission & Storage | 4.7 |
| Customer Service | 2.9 |
| Company Use and Lost Gas | 0.7 |
| Information Technology | 17.0 |
| Corporate Programs | 8.0 |
| Health Care Costs | 2.8 |
| Incentive Compensation | 1.5 |
| Total | $ 56.4 |

I recommend that the Commission reduce the amount of total O&M costs proposed by the Company by ~~$73.3~~$56.4 million and reduce the revenue deficiency accordingly. Exhibit AG-56 CONF Revised provides further details.

## XI. Adjustments To Revenue Deficiency

**Q. WHAT ARE THE TOTAL ADJUSTMENTS AND THE REVISED REVENUE DEFICIENCY YOU RECOMMEND?**

A. Revised Exhibit AG-67 summarizes the adjustments to rate base and operating income. The net result is a revised revenue deficiency of ~~$76.5~~$95.6 million, which is a reduction of ~~$171.5~~$152.4 million from the Company's requested level of $248 million.

I recommend the Commission adopt these adjustments and issue an order granting rate relief to the Company in an amount not exceeding ~~$76.5~~$95.6 million.

## XII. Deferred Accounting Requests

**Q. PLEASE PROVIDE YOUR RECOMMENDATIONS REGARDING THE DEFERRED ACCOUNTING REQUESTS MADE BY THE COMPANY.**

A. In their direct testimony both witnesses Heidy Myers and James Pnacek request that the Commission approve deferred accounting treatment of staking and locating expense because increasing staking volumes and external factors contribute to volatile expense. The Commission should reject this proposal. No compelling evidence has been presented that staking and locating requests have been highly volatile to cause significant expense variations from year to year. The only large variation in expense in this area has been the Company's pursuit to change from a shared contractor model to a Company-only dedicated model, as discussed in more detail in the O&M Expense section of my testimony.

Company witnesses Myers and Pnacek are also requesting that the Commission approve deferred accounting treatment for O&M expenses pertaining to the previously proposed LDAR rule by PHMSA. That rule is currently on hold, and it is not known if and when it will be issued. Approval of deferred accounting at this time is premature and the Commission should deny it.

Witnesses Griffin and Rayl request that the Company receive approval to capitalize MAOP retesting projects. In response to discovery, the Company stated that it does not currently

have any such expenses to capitalize.[178] This request is also premature and there is no need for the Commission to grant approval at this time. More information needs to be gathered from the Company once tangible examples of expenses arise to make a determination whether those expenses truly qualify for capitalization.

Ms. Myers has requested that O&M development costs for the new ERP project be deferred for later amortization and has requested deferred accounting treatment. As discussed earlier in my testimony under the Capital Expenditures section, this project has not been adequately justified, and the Company has not yet completed the vendor bidding process for it to be considered ripe for start of project execution. Until there is a real project ready for execution which has been adequately justified, the Commission should deny the request for deferral of O&M expenses.

## XIII. Rate Design

**Q. WHAT INCREASE IN THE MONTHLY SERVICE CHARGE FOR RESIDENTIAL CUSTOMERS HAS THE COMPANY PROPOSED?**

A. In his direct testimony, Company witness Austin Smith proposes to increase the monthly service charge for residential customers from $15.00 to $20.00 per month. According to his testimony, the proposed monthly service charge reflects a rate of increase considerably

[178] DR AG-CE-0693.

less than the actual customer-related fixed costs calculated in the Company's cost of service study.

**Q. DO YOU AGREE WITH THE COMPANY'S PROPOSAL?**

A. No. The proposed change from $15.00 to $20.00 per month represents an increase of 33%. Such a large increase could cause financial hardship to customers in smaller households who use less gas than the average customer. They would see their monthly gas bill increase without using any more gas. Fixed monthly charges also discourage energy conservation. It is best to increase the volumetric rate paid by customers because the higher cost encourages conservation. The customer can take steps to reduce usage and thus lower the gas bill. The customer cannot reduce fixed monthly charges.

**Q. WHAT DO YOU RECOMMEND?**

A. The Company received a 10% increase in the monthly service charge in the last rate case about one year ago from $13.60 to $15.00. I recommend that the Commission reject the proposed increase and keep the residential customer monthly charge at $15.00.

**Q. WHAT INCREASE IN THE MONTHLY SERVICE CHARGE FOR GENERAL SERVICE GS-1 CUSTOMERS HAS THE COMPANY PROPOSED?**

A. In his direct testimony, Mr. Smith proposes to increase the monthly service charge for customers on Rate GS-1 from $18.00 to $24.00 per month. Although not stated directly

in his testimony, it appears that the proposed monthly service charge for this rate schedule also reflects the actual fixed costs calculated in the Company's cost of service study.

**Q. DO YOU AGREE WITH THE COMPANY'S PROPOSAL?**

A. No. The proposed change from $18.00 to $24.00 per month represents an increase of 33%. Such a large increase could cause some hardship to customers with smaller businesses who use less gas than the average commercial customer. They would see their monthly gas bill increase without using any more gas. As stated above, fixed monthly charges also discourage energy conservation. It is best to increase the volumetric rate paid by customers because the higher cost encourages conservation. The customer can take steps to reduce usage and thus lower the gas bill. The customer cannot reduce fixed monthly charges.

**Q. WHAT DO YOU RECOMMEND?**

A. In the last rate case, the Company received approval to increase the GS-1 monthly customer charge by nearly 13% from $16.00 to $18.00. At this time, I recommend that the Commission should reject the Company's request and keep the month charge at $18.00.

**Q. DOES THIS CONCLUDE YOUR PREPARED DIRECT TESTIMONY?**

A. Yes, it does. However, I reserve the right to amend, revise and supplement my testimony to incorporate new information that may become available.

# Experience and Qualifications of Sebastian Coppola

Mr. Sebastian Coppola is an independent energy business consultant and president of Corporate Analytics, Inc., whose place of business is located at 5928 Southgate Rd., Rochester, Michigan 48306.

## EMPLOYMENT BACKGROUND

Mr. Coppola has been an independent consultant for 22 years. Before that, he spent three years as Senior Vice President and Chief Financial Officer of SEMCO Energy, Inc. with responsibility for all financial operations, corporate development and strategic planning for the company's Michigan and Alaska regulated and non-regulated operations. During the period at SEMCO Energy, he had also responsibility for certain storage and pipeline operations as President and COO of SEMCO Energy Ventures, Inc. Prior to SEMCO, Mr. Coppola was Senior Vice President of Finance for MCN Energy Group, Inc., the parent company of Michigan Consolidated Gas Company (now DTE Gas Company).

## ENERGY INDUSTRY EXPERTISE

During his 27-year career at SEMCO Energy, MCN Energy and MichCon, Mr. Coppola held various analytical, accounting, managerial and executive positions, including Manager of Gas Accounting with responsibility for maintaining the accounting records and preparing financial reports for gas purchases and gas production. In this role, he had also responsibility for preparing Gas Cost Recovery (GCR) reconciliation analysis and reports, and supporting preparation of testimony for the cost of gas reconciliation proceedings before the MPSC. Over the years, Mr. Coppola also held the positions of Treasurer, Director of Investor Relations, Director of Accounting Services, Manager of Corporate Finance, Manager of Customer Billing and Manager of Materials Inventory and Warehousing Accounting. In many



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of these positions he interacted with various operating areas of the company and was intricately involved in construction and operating programs, defining gas purchasing strategies, rate case analysis, cost of capital studies and other regulatory proceedings.

Mr. Coppola is intricately knowledgeable of capital markets and financial institutions. As Treasurer and Vice President of Finance, he directed the issuance of more than $2 billion in securities, including common stock, corporate bonds, tax-deductible preferred stock and high-equity value convertible securities. He established bank lines of credit, commercial paper and asset acquisition facilities. He has had extensive interactions with equity and debt investors, financial analysts, rating agencies and other members of the financial community.

## ENERGY INDUSTRY AND REGULATORY EXPERIENCE

As a business consultant, Mr. Coppola specializes in financial and strategic business issues in the fields of energy and utility regulation. He has more than forty years of experience in public utility and related energy work, both as a consultant and utility company executive. He has testified in several regulatory proceedings before State Public Service Commissions. He has prepared and/or filed testimony in electric and gas general rate case proceedings, power supply and gas cost recovery mechanisms, revenue and cost tracking mechanisms/riders, multi-year rate plans and incentive ratemaking, and other regulatory matters.

Mr. Coppola has extensive experience with gas and electric utilities in the areas of gas operations, gas supply and regulatory proceedings. He has led or participated in the financial operations, gas supply planning and/or gas cost recovery arrangements of two major gas utilities in Michigan and in Alaska. He has prepared

**Experience and Qualifications of Sebastian Coppola**

testimony in multiple electric and gas general rate cases, Power Supply Cost Recovery (PSCR) and Gas Cost Recovery (GCR) reconciliation proceedings, Cast Iron and Pipeline Replacement Programs and other regulatory cases on behalf of the Michigan Attorney General, Citizens Against Rate Excess (CARE), the Public Counsel Division of the Washington Attorney General, the Illinois Attorney General, the Maryland Office of Public Counsel, and the Ohio Office of Consumers Counsel in electric and gas utility rate cases, including AEP Ohio, Ameren-Illinois Utilities, Avista, Consumers Energy, DTE Electric Company, MichCon (DTE Gas Company), Michigan Gas Utilities Corp, Nicor Gas, PacifiCorp, Peoples Gas, Puget Sound Energy, SEMCO, Upper Peninsula Power Company, Washington Gas, and Wisconsin Public Service Company.

Mr. Coppola has also provided assistance and proposals to the Maryland Office of Peoples Counsel on Multi-Year Rate Plans and Performance-Based Ratemaking. Additionally, he prepared a report on the financial condition and risks of AltaGas and Washington Gas Light Company which was filed with the Maryland Public Service Commission in July 2019 in Case No. 9449.

As accounting manager and later financial executive for two regulated gas utilities, he has been intricately involved in construction materials procurement, gas purchase strategies and CGR reconciliation cases. He has had direct responsibility for preparing GCR reconciliation analysis and reports, and supporting preparation of testimony for the cost of gas reconciliation proceedings before the Michigan Public Service Commission (MPSC). He is intricately familiar with construction projects, the power supply and gas cost recovery mechanisms, gas supply and pricing issues, and regulatory issues faced by utilities.

## Experience and Qualifications of Sebastian Coppola

During his long career at DTE Gas, among other responsibilities, Mr. Coppola was responsible to oversee the operation of the MichCon Wet Header System, a pipeline that transported natural gas and gas liquids from Michigan gas producing fields in the Niagaran Reef in the northern area of the lower peninsula of Michigan to processing plants in Kalkaska, MI. His responsibility included ensuring the day-to-day flow of gas and liquids, and identifying operating issues requiring corrective action.

He was also responsible for the study to assess the feasibility of building the Saginaw Bay Pipeline, a transmission line to move Praire Du Chein natural gas reserves in the eastern area of Michigan to processing plants. Prior to the construction of the pipeline, Mr. Coppola worked with operating management to prepare requests for proposal for the construction project and the selection of qualified bids. During and subsequent to the construction of the pipeline, Mr. Coppola assisted in the management and oversight of the pipeline, including review of operating performance and profitability.

Additionally, as Manager of Materials Inventory, Warehousing and Procurement at DTE Gas, Mr. Coppola worked closely with suppliers of pipe, control valves, flanges, meters, fittings, equipment and thousands of other parts and materials used in the construction, repair and maintenance of DTE Gas's transmission, distribution and storage facilities, including repairs and upgrades to compressor stations, and replacement of cast iron mains, bare and wrapped steel pipelines and service lines. His responsibilities included the review of design and construction blueprints and plans with frequent visits to construction sites during excavation of new pipeline trenches, and during replacement of defective or leaky

**Experience and Qualifications of Sebastian Coppola**

pipes, and replacement of control valves. Mr. Coppola also made frequent visits and inspection to storage facilities owned by DTE Gas to understand materials requirements during planned construction projects. Mr. Coppola was also responsible to ensure that materials and equipment were ordered to meet material standards and safety codes.

Through these responsibilities, Mr. Coppola gained knowledge and expertise with field construction project procedures, pipeline trenching problems, installation inspections, operation and maintenance cycles, and the material procurement of pipe, valves, flanges, meters and thousands of other parts and equipment used in the construction of natural gas transmission, distribution and storage facilities.

During his career with MCN Energy Group, Mr. Coppola was responsible for the evaluation of investments in interstate pipelines, new gas storage facilities, gas cogeneration plants, and construction of new power plants in the U.S. and India. Mr. Coppola was a key member of the negotiating team with contractors and suppliers tasked to build the power facilities, including the evaluation of Engineering, Procurement and Construction (EPC) bids and contracts.

Subsequent to his move to SEMCO Energy Corporation in 1999, Mr. Coppola was responsible for the acquisition and integration of pipeline construction companies providing services to gas utilities and interstate pipelines. In addition to its gas utility business in Michigan and Alaska, serving approximately 350,000 customers, SEMCO Energy owned SEMCO Pipeline Construction, a non-regulated business providing gas pipeline and natural gas facilities construction services to gas utilities and interstate pipelines in the Midwest and Eastern regions of the U.S.

## Experience and Qualifications of Sebastian Coppola

SEMCO Pipeline Construction provided construction services similar to KS Energy, Northern Pipeline and other contractors used by the Company. During his tenure at SEMCO Energy, Mr. Coppola reviewed dozens of pipeline construction companies and acquired six companies. Mr. Coppola's responsibilities included management of the performance and profitability of the pipeline construction services business requiring field visits to construction projects and quality reviews. In this process, Mr. Coppola learned firsthand how pipeline construction companies operate, construction project challenges, their bidding practices and the bidding of construction projects, including pricing, bidding procedures and policies both from the contractor's side and the gas utility side.

Mr. Coppola has testified extensively on gas utility pipeline, service lines and inside meters replacement programs related to at-risk pipes that provide safety issues to customers and the general public.

In his role as Treasurer and Chairman of the MCN/MichCon Risk Committee from 1996 through 1998, Mr. Coppola was involved in reviewing and deciding on the appropriate gas purchase price hedging strategies, including the use of gas future contracts, over the counter swaps, fixed price purchases and index price purchases.

In March 2001, Mr. Coppola testified before the Michigan House Energy and Technology Subcommittee on Natural Gas Fixed Pricing Mechanisms. Mr. Coppola frequently participates in natural gas issue forums sponsored by the American Gas Association and stays current on various energy supply issues through review of industry analyst reports and other publications issued by various trade groups.

## Experience and Qualifications of Sebastian Coppola

Mr. Coppola performed rate case analyses and filed testimony in several electric general rate cases addressing issues on revenue requirement, sales level determination, operation and maintenance expenses, capital expenditures, cost allocations, cost of capital, cost of service and rate design, and various cost tracking mechanisms. In addition, he has performed analysis of power costs and filed testimony in power supply cost recovery cases, including reconciliation of annual power supply costs.

In his position as Senior Vice President of Finance at MCN, Mr. Coppola also had responsibility for project financing of independent power generation plants in which MCN was an owner. In this regard, he was intricately involved and became knowledgeable of PURPA qualified cogeneration plants in Michigan and other states. In addition, he was involved in negotiating the development and financing of power generation and electricity distribution plants in other countries, such as India.

- **Specific Regulatory Proceedings and Related Experience:**
  - Filed testimony on behalf of the Michigan Attorney General in Michigan Gas Utilities Corporation (MGUC) 2023-2024 GCR reconciliation in case No. U-21274.
  - Filed testimony on behalf of the Michigan Attorney General in DTE Electric Company (DTEE) 2023 PSCR reconciliation in case No. U-21260.
  - Filed testimony on behalf of the Michigan Attorney General in Consumers Energy Company (CECo) 2023-2024 GCR reconciliation in case No. U-21270.
  - Filed testimony on behalf of the Michigan Attorney General in SEMCO Energy Gas Company (SEMCO) 2023-2024 GCR plan reconciliation in case No. U-21278.
  - Filed testimony on behalf of the Michigan Attorney General in CECo 2023 PSCR reconciliation in case No. U-21258.

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- Filed testimony on behalf of the Michigan Attorney General in CECo 2024 electric rate case U-21585 on several issues, including operation and maintenance expenses, capital expenditures, cost of capital, and other items.
- Filed testimony on behalf of the Michigan Attorney General in DTEE 2024 electric rate case U-21534 on several issues, including operation and maintenance expenses, capital expenditures, cost of capital, and other items.
- Filed testimony on behalf of the Michigan Attorney General in the Upper Peninsula Power Company (UPPCO) 2024 gas rate case U-21555 on several issues, including operation and maintenance expenses, capital expenditures, cost of capital, and other items.
- Filed testimony on behalf of the Michigan Attorney General in MGUC 2024 gas rate case U-21540 on several issues, including operation and maintenance expenses, capital expenditures, cost of capital, and other items.
- Filed testimony on behalf of the Michigan Attorney General in SEMCO Energy Gas Company (SEMCO) 2023-2024 GCR plan in case No. U-21277.
- Filed testimony on behalf of the Michigan Attorney General in DTE Gas Company (DTE Gas) 2024 gas rate case U-21291 on several issues, including sales, operation and maintenance expenses, capital expenditures, cost of capital, and other items.
- Filed testimony on behalf of the Michigan Attorney General in DTE Gas 2022-2023 GCR reconciliation in case No. U-21065.
- Filed testimony on behalf of the Michigan Attorney General in CECo 2023 gas rate case U-21490 on several issues, including sales, operation and maintenance expenses, capital expenditures, cost of capital, and other items.
- Filed testimony on behalf of the Michigan Attorney General in DTM Michigan Lateral Company (DMLC) 2023 Act 9 Transportation Service rate update in case No. U-21525.
- Filed testimony on behalf of the Michigan Attorney General in DTEE 2022 PSCR reconciliation in case No. U-21051.

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- Filed testimony on behalf of the Michigan Attorney General in Michigan Gas Utilities Corporation (MGUC) 2022-2023 GCR plan in case No. U-21067.
- Filed testimony on behalf of the Michigan Attorney General in CECo 2023 PSCR reconciliation in case No. U-21049.
- Filed testimony on behalf of the Michigan Attorney General in Indiana Power Company 2023 electric rate Case U-21461 on several issues, including sales, operation and maintenance expenses, capital expenditures, cost of capital, and other items.
- Filed testimony on behalf of the Michigan Attorney General in DTE 2023-2024 GCR plan in case No. U-21271.
- Filed testimony on behalf of the Michigan Attorney General in CECo 2023-2024 GCR plan in case No. U-21269.
- Filed testimony on behalf of the Michigan Attorney General in CECo 2023 electric rate Case U-21389 on several issues, including operation and maintenance expenses, capital expenditures, cost of capital, and other items.
- Filed testimony on behalf of the Michigan Attorney General in SEMCO Energy Gas Company (SEMCO) 2023-2024 GCR plan in case No. U-21277.
- Filed testimony on behalf of the Michigan Attorney General in DTE Electric Company (DTEE) 2023 rate Case U-21297 on several issues, including operation and maintenance expenses, capital expenditures, cost of capital, and other items.
- Filed testimony on behalf of the Michigan Attorney General in MGUC 2023-2024 GCR plan in case No. U-21273.
- Filed testimony on behalf of the Michigan Attorney General in CECo 2022 gas rate Case U-21308 on several issues, including sales revenues, operation and maintenance expenses, capital expenditures, cost of capital, and other items.
- Filed testimony on behalf of the Michigan Attorney General in DTE Gas 2021-2022 GCR plan reconciliation case No. U-20817.
- Filed testimony on behalf of the Michigan Attorney General in DTEE 2021 PSCR plan reconciliation case No. U-20827.

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- Filed testimony on behalf of the Michigan Attorney General in MGUC 2021-2022 GCR plan reconciliation case No. U-20819.
- Filed testimony on behalf of the Michigan Attorney General in Upper Peninsula Power Company 2022 general rate case No. U-21286.
- Filed testimony on behalf of the Michigan Attorney General in SEMCO 2021-2022 GCR plan reconciliation case No. U-20823.
- Filed testimony on behalf of the Michigan Attorney General in CECo 2022-2023 GCR plan case No. U-21062.
- Filed testimony on behalf of the Michigan Attorney General in SEMCO 2022-2023 GCR plan case No. U-21070.
- Filed testimony on behalf of the Michigan Attorney General in CECo 2022 electric rate Case U-21224 on several issues, including operation and maintenance expenses, capital expenditures, cost of capital, and other items.
- Filed testimony on behalf of the Public Counsel Division of Washington Attorney General in the Avista 2022 electric and gas rate cases on several issues, including operation and maintenance expenses, capital expenditures, and other items.
- Filed testimony on behalf of the Michigan Attorney General in the Act 9 application in Case No. U-20993 by Saginaw Bay Pipeline Company to set transportation rates for services to DTE Gas Company.
- Filed testimony on behalf of the Michigan Attorney General in DTEE 2022 electric rate Case U-20836 on several issues, including operation and maintenance expenses, capital expenditures, cost of capital, and other items.
- Filed rebuttal testimony on behalf the Illinois Attorney General for the reconciliation of the rate surcharge for the Qualified Infrastructure Program (Rider QIP) of the Peoples Gaslight & Coke Company (Peoples Gas) in Docket 17-0137.
- Filed testimony on behalf of the Michigan Attorney General in CECO 2021 gas rate Case U-21148 on several issues, including operation and maintenance expenses, capital expenditures, cost of capital, and other items.

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- Filed testimony on behalf of the Michigan Attorney General in DTE Gas 2020-2021 GCR plan reconciliation case No. U-20554.
- Filed rebuttal testimony on behalf of the Illinois Attorney General for the reconciliation of the rate surcharge for the Qualified Infrastructure Program (Rider QIP) of the Northern Illinois Gas Company (Nicor Gas) in Docket 20-0330.
- Filed testimony on behalf of the Michigan Attorney General in SEMCO 2020-2021 GCR plan reconciliation case No. U-20552.
- Filed testimony on behalf of the Michigan Attorney General in MGUC 2020-2021 GCR plan reconciliation case No. U-20546.
- Filed testimony on behalf of the Michigan Attorney General in CECo 2020 PSCR plan reconciliation case No. U-20526.
- Filed testimony on behalf of the Michigan Attorney General in DTEE 2020 PSCR plan reconciliation case No. U-20528.
- Filed testimony on behalf of the Michigan Attorney General in DTE Gas 2019-2020 GCR plan reconciliation case No. U-20236.
- Filed rebuttal testimony on behalf of the Illinois Attorney General for the reconciliation of the rate surcharge for the Qualified Infrastructure Program (Rider QIP) of the Ameren Illinois Company (Ameren) in Docket 20-0323.
- Filed testimony on behalf of the Michigan Attorney General in DTE Gas 2021-2022 GCR plan case No. U-20816.
- Filed testimony on behalf of the Michigan Attorney General in SEMCO 2021-2022 GCR plan case No. U-20822.
- Filed testimony on behalf of the Michigan Attorney General in CECo 2021 electric rate Case U-20963 on several issues, including operation and maintenance expenses, capital expenditures, cost of capital, and other items.
- Filed testimony on behalf of the Michigan Attorney General in DTE Gas 2021 gas rate Case U-20940 on several issues, including sales, operation and maintenance expenses, capital expenditures, cost of capital, and other items.

## Experience and Qualifications of Sebastian Coppola

- Filed testimony on behalf of the Michigan Attorney General in DTE Michigan Lateral Company (DMCL) 2021 Act 9 filing to convert a pipeline and build two interconnections for transportation services to DTE Gas Company in case No. U-20894.
- Filed testimony on behalf of the Michigan Attorney General in DTEE 2021 power plant and tree trimming securitization costs in case No. U-21015
- Filed testimony on behalf of the Michigan Attorney General in CECo 2021 PSCR plan case No. U-20802.
- Filed testimony on behalf of the Michigan Attorney General in CECo 2019-2020 GCR reconciliation case No. U-20234.
- Filed testimony on behalf of the Maryland Office of Public Counsel in Washington Gas Light Company's 2020 rate Case 9651 on several issues, including operation and maintenance expenses, capital expenditures, and other items.
- Filed testimony on behalf of the Michigan Attorney General in CECo 2020 Karn 1 & 2 Retirement Cost and Bond Securitization Case U-20889.
- Filed testimony on behalf of the Michigan Attorney General in DTEE 2019 PSCR Reconciliation in case U-20222.
- Filed testimony on behalf of the Michigan Attorney General in DTE Gas 2020-2021 GCR plan case No. U-20543.
- Filed testimony on behalf of the Michigan Attorney General in SEMCO Gas Company (SEMCO) 2020-2021 GCR plan case No. U-20551.
- Filed testimony on behalf of the Michigan Attorney General in CECo 2020 electric rate Case U-20697 on several issues, including operation and maintenance expenses, capital expenditures, cost of capital, and other items.
- Filed testimony on behalf of the Michigan Attorney General in in the complaint against Upper Peninsula Power Company's (UPPCO) Revenue Decoupling Mechanism (RDM) in Case No. U-20150.
- Filed testimony on behalf of the Michigan Attorney General in CECo 2019 gas rate Case U-20650 on several issues, including sales,

operation and maintenance expenses, capital expenditures, cost of capital, and other items.

- Filed testimony on behalf of the Michigan Attorney General in DTE Gas Company 2019 gas rate Case U-20642 on several issues, including sales, operation and maintenance expenses, capital expenditures, cost of capital, and other items.
- Filed testimony on behalf of the Michigan Attorney General in DTE Gas 2018-2019 GCR reconciliation Case U-20210.
- Prepared a report on the financial condition and risks of AltaGas and Washington Gas Light Company on behalf of the Maryland Office of People's Counsel filed with the Maryland Public Service Commission in July 2019 in Case No. 9449.
- Filed rebuttal testimony on behalf of the Illinois Attorney General for the reconciliation of the rate surcharge for the Qualified Infrastructure Program (Rider QIP) of the Northern Illinois Gas Company (Nicor Gas) in Docket 19-0294.
- Filed testimony on behalf of the Michigan Attorney General in CECo 2018-2019 GCR reconciliation case U-20209.
- Filed testimony on behalf of the Michigan Attorney General in SEMCO 2018-2019 GCR reconciliation case U-20215.
- Provided assistance and proposals to the Maryland Office of Peoples Counsel on Multi-Year Rate Plans and Performance-Based Ratemaking.
- Filed testimony on behalf of the Michigan Attorney General in DTEE 2018 PSCR Reconciliation in case U-20203.
- Filed testimony on behalf of the Michigan Attorney General in CECo 2018 PSCR Reconciliation in case U-20202.
- Filed direct testimony on behalf of the Illinois Attorney General for the reconciliation of the rate surcharge for the Qualified Infrastructure Program (Rider QIP) of the Northern Illinois Gas Company (Nicor Gas) in Docket 19-0294.
- Filed testimony on behalf of the Michigan Attorney General in DTEE 2019 electric rate Case U-20561 on several issues, including sales,

**Experience and Qualifications of Sebastian Coppola**

operation and maintenance expenses, capital expenditures, cost of capital, and other items.

- Filed testimony on behalf of the Michigan Attorney General in Indiana Michigan Power Company (I&M) 2019 electric rate Case U-20239 on several issues, including operation and maintenance expenses, capital expenditures, cost of capital, rate design and other items.
- Filed testimony on behalf of the Michigan Attorney General in SEMCO 2019 gas rate Case U-20479 on several issues, including sales, operation and maintenance expenses, capital expenditures, cost of capital, rate design and other items.
- Filed testimony on behalf of the Michigan Attorney General in SEMCO 2019-2020 GCR Plan case U-20245.
- Filed testimony on behalf of the Michigan Attorney General in CECo 2019-2020 GCR Plan case U-20233.
- Filed testimony on behalf of the Michigan Attorney General in DTEE 2019 PSCR Plan case U-20221.
- Filed testimony on behalf of the Michigan Attorney General in DTE Gas 2019-2020 GCR Plan case U-20235.
- Filed testimony on behalf of the Michigan Attorney General in Michigan Gas Utilities Corporation (MGUC) 2019-2020 GCR plan case U-20239.
- Filed rebuttal testimony on behalf of the Illinois Attorney General in Nicor Gas 2018 rate case on capital expenditures and rate base additions in Docket 18-1775.
- Filed testimony on behalf of the Michigan Attorney General in DTE Gas 2017-2018 GCR reconciliation case U-20076.
- Filed testimony on behalf of the Michigan Attorney General in CECo 2017-2018 GCR reconciliation case U-20075.
- Filed testimony on behalf of the Michigan Attorney General in CECo 2018 gas rate Case U-20322 on several issues, including operation and maintenance expenses, capital expenditures, cost of capital, rate design and other items.

## Experience and Qualifications of Sebastian Coppola

- Filed testimony on behalf of the Michigan Attorney General in I&M Tax Credit C Calculation in case U-20317.
- Filed direct testimony on behalf of the Illinois Attorney General in Nicor Gas 2018 rate case on capital expenditures and rate base additions in Docket 18-1775.
- Filed testimony on behalf of the Michigan Attorney General in DTE Gas Tax Credit C Calculation in case U-20298.
- Filed testimony on behalf of the Michigan Attorney General in MGUC 2017-2018 GCR Reconciliation case U-20078.
- Filed testimony on behalf of the Michigan Attorney General in CECo Tax Credit C Calculation for the Gas and Electric Divisions in case U-20309.
- Filed testimony on behalf of the Michigan Attorney General in Upper Peninsula Power Company 2018 electric rate Case U-20276 on several issues, including excess deferred taxes, cost of capital, rate design and other items.
- Filed testimony on behalf of the Michigan Attorney General in CECo 2017 PSCR Reconciliation in case U-20068.
- Filed testimony on behalf of the Michigan Attorney General in DTEE 2018 rate Case U-20162 on several issues, including operation and maintenance expenses, capital expenditures, cost of capital, rate design and other items.
- Filed testimony on behalf of the Michigan Attorney General in CECo 2018 Tax Credit B refund for the Electric Division in case U-20286.
- Filed testimony on behalf of the Michigan Attorney General in CECo 2018 Integrated Resource Plan in case U-20165.
- Filed testimony on behalf of the Michigan Attorney General in CECo 2018 Tax Credit B refund case U-20287 for the natural gas business.
- Filed testimony on behalf of the Michigan Attorney General in DTE Gas 2018 Tax Credit B refund case U-20189.
- Filed testimony on behalf of the Michigan Attorney General in CECo 2018 electric rate Case U-20134 on several issues, including capital expenditures, cost of capital, rate design and other items.

## Experience and Qualifications of Sebastian Coppola

- Filed direct testimony on behalf of the Illinois Attorney General for the reconciliation of the rate surcharge for the Qualified Infrastructure Program (Rider QIP) of the Peoples Gas and Coke Company's (Peoples Gas) in Docket 16-0197.
- Filed testimony on behalf of the Michigan Attorney General in DTE Gas 2016-2017 GCR reconciliation case U-17941-R.
- Filed testimony on behalf of the Michigan Attorney General in SEMCO 2018-2019 GCR Plan case U-18417.
- Filed testimony on behalf of the Michigan Attorney General in CECo 2018 Tax Credit A refund case U-20102.
- Filed testimony on behalf of the Michigan Attorney General in I&M 2018 PSCR Plan case U-18404.
- Filed testimony on behalf of the Michigan Attorney General in DTE Gas 2018-2019 GCR Plan case U-18412.
- Filed testimony on behalf of the Michigan Attorney General in Upper Peninsula Power Company (UPPCO) 2018 Tax Credit A refund case U-20111.
- Filed testimony on behalf of the Michigan Attorney General in DTE Gas 2018 Tax Credit A refund case U-20106.
- Filed testimony on behalf of the Michigan Attorney General in DTEE 2018 PSCR Plan case U-18403.
- Filed testimony on behalf of the Michigan Attorney General in CECo 2018 PSCR Plan case U-18402.
- Filed testimony on behalf of the Michigan Attorney General in DTE Gas 2017 gas rate Case U-18999 on several issues, including revenue, operations and maintenance costs, capital expenditures, cost of capital, rate design and other items.
- Filed testimony on behalf of the Michigan Attorney General in CECo 2017 gas rate Case U-18424 on several issues, including revenue, operations and maintenance costs, capital expenditures, cost of capital, rate design and other items.
- Filed testimony on behalf of the Michigan Attorney General in CECo 2016 PSCR reconciliation case U-17918-R.

## Experience and Qualifications of Sebastian Coppola

- Assisted the Michigan Attorney General in the review of several GCR and PSCR cases during 2017 and 2018, and proposed terms for settlement of those cases.
- Assisted the Michigan Attorney General in the filing of comments with the Michigan Public Service Commission relating to rate case filing requirements in case U-18238, refunds of tax savings from the lower federal tax rate in case U-18494 and Performance Based Regulation.
- Filed direct and rebuttal testimony on behalf of the Illinois Attorney General for the reconciliation of the rate surcharge for the Qualified Infrastructure Program (Rider QIP) of the Peoples Gas and Coke Company's (Peoples Gas) in Docket 15-0209.
- Filed testimony on behalf of the Michigan Attorney General in DTEE 2017 electric Rate Case U-18255 on a several issues, including revenue, operations and maintenance costs, capital expenditures, cost of capital, rate design and other items.
- Filed testimony on behalf of the Michigan Attorney General in CECo 2017 electric rate Case U-18322 on a several issues, including revenue, operations and maintenance costs, capital expenditure programs, cost of capital and other items.
- Filed direct and rebuttal testimony on behalf of the Illinois Attorney General for the re-opening of proceedings in the restructuring of the Peoples Gas's main replacement program and gas system modernization plan in Docket 16-0376.
- Filed testimony on behalf of the Michigan Attorney General in the Upper Michigan Energy Resources Corporation (UMERC) application for a certificate of public necessity and convenience to build two power plants in the Upper Peninsula of Michigan in case U-18202.
- Filed testimony on behalf of the Michigan Attorney General in SEMCO application for a certificate of public necessity and convenience to build a pipeline in the Upper Peninsula of Michigan in case U-18202.
- Filed testimony on behalf of the Public Counsel Division of the Washington Attorney General in Puget Sound Energy's 2016 Complaint for Violation of Gas Safety Rules in Docket No. UE-160924.

## Experience and Qualifications of Sebastian Coppola

- Filed testimony on behalf of the Michigan Attorney General in DTEE 2017 PSCR Plan case U-18143.
- Filed testimony on behalf of the Michigan Attorney General in CECo 2015 Power Supply Cost Recovery (PSCR) reconciliation case U-17678-R.
- Filed testimony on behalf of the Michigan Attorney General in CECo 2016 gas general rate case U-18124 on a several issues, including revenue, operations and maintenance costs, capital expenditures, working capital, cost of capital and other items.
- Filed testimony on behalf of the Illinois Attorney General for the restructuring of the Peoples Gas's main replacement program in Docket 16-0376.
- Filed testimony on behalf of the Michigan Attorney General in DTE Gas 2014-2015 GCR Plan reconciliation case U-17332-R.
- Filed testimony on behalf of the Michigan Attorney General in the formation of UMERC and the transfer of Michigan assets of Wisconsin Public Service Corporation and Wisconsin Electric Company to UMERC in Case U-18061.
- Filed testimony on behalf of the Michigan Attorney General in CECo Court of Appeals Remand Case U-17087 for review of the Automated Meter Infrastructure (AMI) opt-out fees.
- Filed testimony on behalf of the Michigan Attorney General in CECo 2016 electric Rate Case U-17990 on a several issues, including revenue, operations and maintenance costs, capital expenditure programs, cost of capital, rate design and other items.
- Filed testimony on behalf of the Michigan Attorney General in Michigan Gas Utilities Corporation (MGUC) 2016-2017 GCR Plan case U-17940.
- Filed testimony on behalf of the Michigan Attorney General in DTEE 2016 electric Rate Case U-18014 on a several issues, including revenue, revenue decoupling, operations and maintenance costs, capital expenditures, cost of capital, rate design and other items.
- Filed testimony on behalf of the Michigan Attorney General in SEMCO 2016-2017 GCR Plan case U-17942.

## Experience and Qualifications of Sebastian Coppola

- Filed testimony on behalf of the Michigan Attorney General in DTE Gas 2016-2017 GCR Plan case U-17941.
- Filed testimony on behalf of the Michigan Attorney General in DTE Gas 2015 gas general rate case U-17999 on a several issues, including revenue, operations and maintenance costs, capital expenditures, main replacement program, Revenue Decoupling Mechanism (RDM) program, cost of capital and other items.
- Filed testimony on behalf of the Michigan Attorney General in CECo 2016-2017 GCR Plan case U-17943.
- Filed testimony on behalf of the Michigan Attorney General in CECo 2016 PSCR Plan case U-17918.
- Filed testimony on behalf of the Michigan Attorney General in CECo 2014-2015 GCR Plan reconciliation case U-17334-R.
- Filed testimony on behalf of the Michigan Attorney General in DTEE 2016 PSCR Plan case U-17920.
- Filed testimony on behalf of the Michigan Attorney General in SEMCO 2014-2015 GCR Plan reconciliation case U-17333-R.
- Filed testimony on behalf of the Michigan Attorney General in CECo 2015 gas general rate case U-17882 on a several issues, including revenue, operations and maintenance costs, capital expenditures, main replacement program, infrastructure cost recovery mechanism, cost of capital and other items..
- Filed testimony on behalf of the Michigan Attorney General in CECo Gas Choice and End-User Transportation tariff changes case U-17900.
- Analyzed the gas rate case filings of MGUC in Case U-17880 and assisted the Michigan Attorney General in settlement of the case.
- Filed testimony on behalf of the Michigan Attorney General in CECo 2014 PSCR reconciliation case U-17317-R.
- Filed testimony on behalf of the Michigan Attorney General in DTE Gas 2013-2014 GCR Plan reconciliation case U-17131-R.
- Filed testimony on behalf of the Michigan Attorney General in DTEE 2014 electric Rate Case U-17767 on a several issues, including

**Experience and Qualifications of Sebastian Coppola**

operations and maintenance costs, capital expenditures, AMI program, cost of capital and other items.

- Filed testimony on behalf of the Michigan Attorney General in DTE Gas 2015-2016 GCR Plan case U-17691.
- Filed testimony on behalf of the Illinois Attorney General in Ameren Illinois Company's 2015 general rate case on operation and maintenance costs in Docket 15-0142.
- Filed testimony on behalf of the Michigan Attorney General in CECo 2014 electric Rate Case U-17735 on a several issues, including sales, operations and maintenance costs, capital expenditures, cost of capital, AMI program, revenue decoupling and infrastructure cost recovery mechanisms.
- Filed testimony on behalf of the Michigan Attorney General in CECo 2015-2016 GCR Plan case U-17693.
- Filed testimony on behalf of the Michigan Attorney General in MGUC 2015-2016 GCR Plan case U-17690.
- Filed testimony on behalf of the Michigan Attorney General in CECo 2015 PSCR Plan case U-17678.
- Analyzed the electric rate case filings of Northern States Power in Case U-17710 and Wisconsin Public Service Company U-17669, and assisted the Michigan Attorney General in settlement of these cases.
- Filed testimony on behalf of the Michigan Attorney General in CECo 2013-2014 GCR Plan reconciliation case U-17133-R.
- Filed testimony on behalf of the Michigan Attorney General in MGUC 2013-2014 GCR Plan reconciliation cases U-17130-R.
- Filed testimony on behalf of the Michigan Attorney General in SEMCO 2013-2014 GCR Plan reconciliation case U-17132-R.
- Filed testimony on behalf of the Michigan Attorney General in CECo 2014 gas general rate case U-17643 on a several issues, including revenue, operations and maintenance costs, capital expenditures, main replacement program, cost of capital and other items..

## Experience and Qualifications of Sebastian Coppola

- Filed testimony on behalf of the Illinois Attorney General in Wisconsin Energy merger with Integrys on the Peoples Gas and Coke Company's Accelerated Main Replacement Program Docket 14-0496.
- Filed testimony on behalf of Citizens Against Rate Excess in Wisconsin Public Service Company's 2013 PSCR plan reconciliation case U-17092-R.
- Filed testimony on behalf of the Michigan Attorney General in CECo 2014 PSCR plan case U-17317.
- Filed testimony on behalf of the Michigan Attorney General in CECo 2014 OPEB Funding case U-17620.
- Filed testimony on behalf of the Michigan Attorney General in SEMCO 2014-2015 GCR Plan case U-17333.
- Filed testimony on behalf of the Michigan Attorney General in MGUC 2014-2015 GCR Plan case U-17331.
- Filed testimony on behalf of the Michigan Attorney General in CECo 2014-2015 GCR Plan case U-17334.
- Filed testimony for Citizens Against Rate Excess in Wisconsin Public Service Company's 2014 PSCR plan case U-17299.
- Filed testimony in March 2013 on behalf of the Michigan Attorney General in CECo's electric Rate Case U-15645 on remand from the Michigan Court of Appeals for review of the AMI program.
- Filed testimony for Citizens Against Rate Excess in Upper Peninsula Power Company's 2012 PSCR plan case U-17298.
- Filed testimony on behalf of the Michigan Attorney General in MGUC 2012-2013 GCR Reconciliation case U-16920-R.
- Filed testimony on behalf of the Michigan Attorney General in DTE Gas Company 2012-2013 GCR Reconciliation case U-16921-R.
- Filed testimony on behalf of the Michigan Attorney General in CECo 2012-2013 GCR Reconciliation case U-16924-R.
- Filed testimony on behalf of the Michigan Attorney General in SEMCO 2012-2013 GCR Reconciliation case U-16922-R.

## Experience and Qualifications of Sebastian Coppola

- Filed testimony for Citizens Against Rate Excess in Upper Peninsula Power Company's 2012 Power Supply Cost Recovery (PSCR) reconciliation case U-16881-R.
- Filed testimony in Puget Sound Energy's 2013 Power Cost Only Rate Case on behalf of the Public Counsel Division of the Washington Attorney General in Docket No. UE-130167 on the power costs adjustment mechanism.
- Filed testimony in PacifiCorp's 2013 General Rate Case on behalf of the Public Counsel Division of the Washington Attorney General in Docket No. UE-130043 on power costs, cost allocation factors, O&M expenses and power cost adjustment mechanisms.
- Filed testimony on behalf of the Michigan Attorney General in SEMCO 2013-2014 GCR Plan case U-17132.
- Filed testimony on behalf of the Michigan Attorney General in MGUC 2013-2014 GCR Plan case U-17130.
- Filed testimony on behalf of the Michigan Attorney General in CECo's 2012 electric Rate Case U-17087 on a several issues, including cost of service methodology, rate design, operations and maintenance costs, capital expenditures and infrastructure cost recovery mechanism and other revenue/cost trackers.
- Filed reports on gas procurement and hedging strategies of four gas utilities before the Washington Utilities and Transportation Commission on behalf of the Washington Attorney General – Office of Public Counsel in April 2013.
- Filed testimony on behalf of the Michigan Attorney General in MGUC and SEMCO 2011-2012 GCR Plan reconciliation cases U-16481-R and U-16483-R.
- Filed testimony for Citizens Against Rate Excess in Upper Peninsula Power Company's 2012 Power Supply Cost Recovery (PSCR) plan case U-17091.
- Filed testimony in MichCon's 2012 gas Rate Case U-16999 on a several issues, including sales volumes, revenue decoupling mechanism, operations and maintenance costs, capital expenditures and infrastructure cost recovery mechanism.

## Experience and Qualifications of Sebastian Coppola

- Filed testimony on behalf of the Washington Attorney General – Office of Public Counsel on executive and board of directors' compensation in the 2012 Avista general rate case.
- Filed testimony for Citizens Against Rate Excess in Upper Peninsula Power Company's 2011 Power Supply Cost Recovery (PSCR) reconciliation case U-16421-R.
- Filed testimony on behalf of the Ohio Office of Consumers Counsel in AEP Ohio's power supply restructuring case in June 2012.
- Filed testimony on behalf of the Michigan Attorney General in MGUC and SEMCO 2012-2013 GCR Plan cases U-16920 and U-16922.
- Filed testimony for Citizens Against Rate Excess in Upper Peninsula Power Company's 2012 PSCR plan case U-16881.
- Filed testimony for Citizens Against Rate Excess in Wisconsin Public Service Corporation's 2012 PSCR plan case U-16882.
- Filed testimony for the Michigan Attorney General in CECo's gas business Pilot Revenue Decoupling Mechanism in case U-16860.
- Filed testimony for the Michigan Attorney General in Consumers Energy Gas 2011 Rate Case U-16855 on several issues, including sales volumes, operations and maintenance cost, employee benefits, capital expenditures and cost of capital.
- Filed testimony for the Michigan Attorney General in SEMCO and MGUC 2010-2011 GCR Plan reconciliation cases U-16147-R and U-16145-R.
- Filed testimony for the Michigan Attorney General in Consumers Energy 2011 electric Rate Case U-16794 on several issues, including electric sales forecast, revenue decoupling mechanism, operations and maintenance cost, employee benefits, capital expenditures and cost of capital.
- Filed testimony for the Michigan Attorney General in CECo's electric business Pilot Revenue Decoupling Mechanism in case U-16566.
- Filed testimony on behalf of the Michigan Attorney General in SEMCO and MGUC 2011-2012 GCR Plan cases U-16483 and U-16481.

## Experience and Qualifications of Sebastian Coppola

- Filed testimony for the Michigan Attorney General in Detroit Edison 2010 electric Rate Case U-16472 on several issues, including revenue decoupling mechanism, operations and maintenance cost, executive compensation and benefits, capital expenditures and cost of capital.
- Filed testimony for the Michigan Attorney General in SEMCO 2009-2010 GCR reconciliation case U-15702-R.
- Filed testimony for Michigan Attorney General in MGUC 2009-2010 GCR reconciliation case U-15700-R.
- Filed testimony for Michigan Attorney General, in Consumers Energy Gas 2010 Rate Case U-16418 on several issues, including sales volumes, operations and maintenance costs, capital expenditures and cost of capital.
- Filed testimony for Michigan Attorney General, in SEMCO 2010 Rate Case U-16169 on several issues, including sales volumes, rate design, operations and maintenance cost, executive compensation and benefits, capital expenditures and cost of capital.
- Filed testimony, for Michigan Attorney General in Consumers Energy 2009 electric Rate Case U-16191 on several issues, including sales volumes, revenue decoupling mechanism, operations and maintenance cost and capital expenditures.
- Filed testimony for Michigan Attorney General, in MichCon 2009 gas Rate Case U-15985 on several issues, including sales volumes, revenue decoupling mechanism, operations and maintenance cost, capital expenditures and cost of capital.
- Filed testimony for Michigan Attorney General and was cross-examined in Consumers Energy 2009 gas Rate Case U-15986 on several issues, including sales volumes, revenue decoupling mechanism, operations and maintenance cost, capital expenditures and cost of capital.
- Prepared testimony and assisted the Michigan Attorney General in discussions and settlement of SEMCO and MGUC 2010-2011 GCR Plan cases U-16147 and U-16145.
- Prepared testimony and assisted Michigan Attorney General in settlement of SEMCO 2009-2010 GCR case U-15702.

## Experience and Qualifications of Sebastian Coppola

- Prepared testimony and assisted Michigan Attorney General in settlement of MGUC 2009-2010 GCR case U-15700.
- Prepared testimony and assisted the Michigan Attorney General in discussions and settlement of SEMCO 2008-2009 GCR case U-15452 and reconciliation case U-15452-R.
- Prepared testimony and assisted Michigan Attorney General in discussions and settlement of MGUC 2008-2009 GCR reconciliation case U-15450-R.
- Prepared testimony for Michigan Attorney General in SEMCO GCR 2007-2008 Reconciliation Case U-15043-R.
- Prepared testimony for Michigan Attorney General filed in MGUC 2007-2008 GCR Reconciliation Case U-15040-R.
- Participated in drafting of testimony for all aspects of SEMCO rate case filing with the Regulatory Commission of Alaska (RCA) in 2001.
- Filed testimony in 2001 before the (RCA) and was cross-examined on the financing plans for the acquisition of Enstar Corporation and the capital structure of SEMCO.
- Developed a cost of capital study in support of testimony by company witness in the Saginaw Bay Pipeline Company rate request proceeding in 1989.
- Prepared testimony for company witness on cost of capital and capital structure in MichCon 1988 gas rate case.
- Filed testimony in MichCon gas conservation surcharge case in 1986-87.
- Testified before MPSC ALJ in MichCon customer bill collection complaints in 1983.
- Participated in analysis of uncollectible gas accounts expense for inclusion in rate filings between 1975 and 1988.
- Participated in analysis of allocation of corporate overhead to subsidiaries and use of the “Massachusetts Formula” at MichCon and at SEMCO in 1975 and 2000.
- Prepared support information on GCR and rate case-O&M testimony at MichCon from 1975 to 1988.

**Experience and Qualifications**
**of Sebastian Coppola**

- Filed testimony in MichCon financing orders in 1987 and 1988.
- Participated in rate case filing strategy sessions at MichCon and SEMCO from 1975 to 2001.
- Provided Hearing Room assistance and guidance to counsel on financial and policy issues in various cases from 1975 to 2001.

**EDUCATIONAL BACKGROUND**

Mr. Coppola did his undergraduate work at Wayne State University, where he received the Bachelor of Science degree in Accounting in 1974. He later returned to Wayne State University to obtain his Master of Business Administration degree with major in Finance in 1980.



(Revised Direct Testimony bound in the Confidential Record)

MS. GILL: And then also, Your Honor, in lieu of cross-examining certain Consumers Energy witnesses, the Company has agreed and the Attorney General moves for the admission of various discovery responses as exhibits. Those exhibits were previously uploaded to the Sharepoint site for the case and have been organized as Exhibits AG-68 through AG-85.

JUDGE VARCHETTI: All right. Are there any objections to the admission of Exhibits AG-68 through AG-85?

I am hearing none, so those exhibits are admitted.

MS. GILL: Okay. And that completes the Attorney General's presentation.

JUDGE VARCHETTI: Thank you.

Is there any party that wishes to go next in their evidentiary presentation? Mr. Campbell, I'm seeing you raise your hand.

MR. CAMPBELL: Yes. Thank you, Your Honor. We can go next, if that's appropriate.

JUDGE VARCHETTI: That is wonderful. You can proceed.

MR. CAMPBELL: Thank you. And we have

three witnesses. Would you like me to pause after each one?

JUDGE VARCHETTI: Yes, please.

MR. CAMPBELL: Thank you, Your Honor.

At this time, on behalf of the Association of Businesses Advocating Tariff Equity, I'd move to bind into the record the prefiled direct and rebuttal testimony of ABATE witnesses Jessica A. York, Colin T. Fitzhenry, and Christopher C. Walters, and for admission of their associated exhibits.

Ms. York's testimony consists of a cover page, a table of contents, 39 pages of questions and answers, an Appendix A setting out her qualifications, and along with her direct testimony, Ms. York sponsored Exhibits AB-1 through AB-4.

And Ms. York's rebuttal testimony consists of a cover page, a table of contents, 14 pages of questions and answers, and along with her rebuttal testimony, Ms. York sponsored Exhibits AB-21 through AB-23.

JUDGE VARCHETTI: All right. Are there any objections to the admission of Ms. York's direct and rebuttal testimony or the associated exhibits?

I am hearing none, so her testimony is bound into the record, and the associated exhibits are

admitted.

MR. CAMPBELL: Thank you, Your Honor.

(Direct, Appendix A, and Rebuttal Testimony bound in)

**STATE OF MICHIGAN**
**BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION**

| | | |
|---|---|---|
| **In the matter of the application of CONSUMERS ENERGY COMPANY for authority to increase its rates for the distribution of natural gas and for other relief.** | ) | **Case No. U-21806** |

Direct Testimony and Exhibits of

**Jessica A. York**

On behalf of

**Association of Businesses Advocating Tariff Equity**

April 23, 2025

BRUBAKER & ASSOCIATES, INC.

Project 11775

**STATE OF MICHIGAN**
**BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION**

| | | |
|---|---|---|
| **In the matter of the application of CONSUMERS ENERGY COMPANY for authority to increase its rates for the distribution of natural gas and for other relief.** | ) | **Case No. U-21806** |

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Appendix A: Qualifications of Jessica A. York

Exhibit AB-1: Referenced Responses to Discovery Requests

Exhibit AB-2: Information from Consumers' Gas Cost Recovery Plan for YE March 31, 2025

Exhibit AB-3: Calculation of 2024 Revenue Sufficiency

Exhibit AB-4: Proposed Transportation Rate Design

**STATE OF MICHIGAN**
**BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION**

| | | |
|---|---|---|
| **In the matter of the application of CONSUMERS ENERGY COMPANY for authority to increase its rates for the distribution of natural gas and for other relief.** | ) | **Case No. U-21806** |

# Direct Testimony of Jessica A. York

## I. INTRODUCTION

**Q PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.**

A Jessica A. York. My business address is 16690 Swingley Ridge Road, Suite 140, Chesterfield, MO 63017.

**Q WHAT IS YOUR OCCUPATION?**

A I am a consultant in the field of public utility regulation and a Principal with the firm of Brubaker & Associates, Inc. ("BAI"), energy, economic and regulatory consultants.

**Q PLEASE DESCRIBE YOUR EDUCATIONAL BACKGROUND AND EXPERIENCE.**

A This information is included in Appendix A to my testimony.

**Q ON WHOSE BEHALF ARE YOU APPEARING IN THIS PROCEEDING?**

A I am appearing on behalf of the Association of Businesses Advocating Tariff Equity ("ABATE"). ABATE consists of large usage customers that purchase substantial amounts of electric power and/or delivery service from Consumers Energy Company ("Consumers" or "Company").

**Q PLEASE BRIEFLY SUMMARIZE ABATE'S WITNESSES IN THIS PROCEEDING AND THE ISSUES THEY ARE ADDRESSING IN DIRECT TESTIMONY.**

A ABATE is providing Direct Testimony in this proceeding from three witnesses: Colin T. Fitzhenry, Christopher C. Walters, and myself.

I provide an overview of the Direct Testimonies of ABATE's witnesses and then address: (i) Consumers' use of a projected test year; (ii) Consumers' proposed Class Cost of Service Study ("CCOSS"); (iii) Consumers' proposed revenue allocation; and (iv) Consumers' proposed gas transportation rate design.

Mr. Fitzhenry addresses Consumers' proposed projected test year Operation and Maintenance ("O&M") expense levels as well as certain capital expenditure amounts that Consumers has projected it will incur either during its proposed projected test year or during the bridge period between the end of Consumers' proposed historic year and the beginning of its proposed projected test year.

Mr. Walters addresses Consumers' proposed Return on Equity ("ROE") and capital structure.

Table JAY-1 summarizes ABATE's recommended downward adjustments to the Company's proposed revenue requirement increase. In total, ABATE's adjustments reduce the Company's claimed revenue deficiency in this proceeding by $67.9 million. The Capital Expenditure adjustments in Table JAY-1 assume the Michigan Public Service Commission ("MPSC" or "Commission") adopts Mr. Walters' Rate of Return ("ROR") recommendation of an equity ratio of 50% and an authorized ROE of 9.45%. If despite Mr. Walters' recommendation the Commission were to instead adopt an authorized ROE greater than 9.45%, the listed downward revenue requirement adjustment associated with projected capital expenditures would be larger. Mr. Fitzhenry details this in his Direct Testimony.

**TABLE JAY-1**

**ABATE Revenue Requirement Adjustments**
**($ Millions)**

| Line | Description | Amount |
|---|---|---|
| | Adjustments: | |
| 1 | O&M Expenses | $1.7 |
| 2 | Projected Capital Expenditures[1] | $6.2 |
| 3 | Return on Equity and Equity Ratio | $60.0 |
| 4 | Total of ABATE Revenue Requirement Adjustments | $67.9 |

Notes:
[1] This is at ABATE's recommended ROE of 9.45% and common equity ratio of 50%. At Consumers' proposed ROE of 10.25% and equity ratio of 50.75%, this adjustment would be $7.2 million.

My silence in this testimony, or that of my colleagues in their own testimony, with regard to any issue should not be construed as an endorsement of Consumers' position on that issue. In particular, I would like to emphasize that we did not attempt to identify all of the downward adjustments that should be made to Consumers' proposed revenue deficiency and it is likely other intervenors and the Commission Staff ("Staff") will propose additional downward adjustments beyond those we have recommended which should be adopted.

**Q PLEASE BRIEFLY SUMMARIZE YOUR CONCLUSIONS AND RECOMMENDATIONS IN THIS PROCEEDING.**

A My conclusions and recommendations are as follows:

1. As detailed in the Direct Testimony of ABATE witnesses Mr. Fitzhenry and Mr. Walters, at least $67.9 million of Consumers' proposed $248.0 million rate increase in this proceeding is unwarranted, unsupported or both. As a minimum, this portion of Consumers' proposed rate increase should be denied.

2. Consumers' recent rate increases have been driven by the use of projected rather than historical test years for ratemaking and aggressive capital expenditures[1] coupled with the filing of frequent rate cases.

3. In this proceeding, and in seven out of eight of Consumers' most recent previous rate filings, the Company has reported a revenue sufficiency for its filed historical test year indicating recurring instances of Consumers earning revenues in excess of its authorized amount due to the continuing use of a projected test year. Given this track record with respect to the use of a projected test year, the Commission should reject the Company's proposed use of a projected test year in this proceeding and require it to use its proposed historical test year as the basis of its revenue requirement. Given that Consumers is reporting a revenue sufficiency for its historical test year in this proceeding, this would result in no revenue requirement increase in this case.

4. If, despite my recommendation, the Commission allows Consumers to use a projected test year in this proceeding, the Commission should be vigilant to ensure the following: (i) that the projected expenses and investments included in the Company's projected test year are truly necessary to provide reliable service at the lowest reasonable cost; (ii) that Consumers is essentially irrevocably committed to incur them or otherwise cannot avoid them; and (iii) they are precisely quantified by Consumers with respect to their amount and timing.

5. As was recommended in ABATE's May 14, 2021 and August 11, 2021 filed Comments in Case No. U-18238, and its September 27, 2024 filed Comments in Case No. U-21637, the Commission, within the context of the Commission's minimum filing requirements or a generic proceeding, should examine the issue of projected test years continuing to result in excess revenue being collected from customers.

6. The Company's proposed CCOSS relies on the Peak and Average ("P&A") method for the allocation of Transmission and Distribution ("T&D") capacity costs. The P&A method does not accurately reflect cost-causation.

7. The Company's proposed revenue apportionment results in about a 2.0 times system average increase for Rate ST, and approximately a 1.6 times system average increase for Rates LT and XLT. These proposed increases are based on the results of a flawed and inaccurate CCOSS.

8. The Company has provided evidence showing that Design Day Demand is the load characteristic that drives investment in T&D capacity costs. Thus, a Design Day Demand allocation of these costs would produce the most accurate measure of the Company's cost of providing service to each customer class.

9. However, to the extent that the Commission prefers to continue relying on a partial energy-weighted method of allocating capacity costs, it would be more reasonable

[1]For example, Consumers filing is driven by continued infrastructure investment and increasing operations and maintenance costs. Furthermore, Consumers identified $135 million of its $248.0 million proposed revenue requirement increase being related to growth in its rate base. (Direct Testimony of Heidi Myers at page 4).

to rely on the Average and Excess Demand ("AED") method instead of the P&A method.

10. Relative to the P&A method, the AED method more accurately assigns the T&D capacity costs to the lower-load factor, weather-sensitive customer classes that drive the need for capacity in excess of the amount needed to provide firm service to the system and each customer class on non-peak days.

11. I recommend an alternative revenue apportionment and rate design which considers the results of both Consumers' proposed revenue allocation and the AED CCOSS and reflects a more equitable revenue allocation than proposed by the Company. My recommended revenue apportionment is shown in Table JAY-4, and my recommended transportation rate design is shown in Exhibit AB-4.

## II. PROJECTED TEST YEAR

**Q YOU HAVE ALLEGED THAT, ALONG WITH THE PURSUIT OF AGGRESSIVE CAPITAL EXPENDITURES, CONSUMERS' USE OF A PROJECTED TEST YEAR IS A MAJOR DRIVER OF ITS PROPOSED RATE INCREASE IN THIS PROCEEDING. PLEASE EXPLAIN WHY THIS IS THE CASE.**

A The best starting point for exploring this issue is to compare Consumers' own historical and projected test year calculations for this case and several of its most recent gas rate cases. I present this comparison in Table JAY-2.

**TABLE JAY-2**

**Historical Test Year and Projected Test Year**
**Rate Sufficiency / (Deficiency)**

| Line | Case No. | Historical Test Year Sufficiency / (Deficiency) (1) | Projected Test Year Sufficiency / (Deficiency) (2) | Difference Between Historical and Projected (3) |
|---|---|---|---|---|
| 1 | U-18124 | $ 264,000 | $ (90,485,000) | $ (90,749,000) |
| 2 | U-18424 | 35,283,000 | (178,194,000) | (213,477,000) |
| 3 | U-20322 | 33,458,000 | (229,258,000) | (262,716,000) |
| 4 | U-20650 | (83,936,000) | (244,744,000) | (160,808,000) |
| 5 | U-21148 | 29,000,000 | (278,421,000) | (307,421,000) |
| 6 | U-21308 | 17,658,000 | (211,900,000) | (229,558,000) |
| 7 | U-21490 | 2,682,000 | (136,034,000) | (138,716,000) |
| 8 | U-21806 | 9,443,000 | (248,008,000) | (257,451,000) |
| 9 | Total | $ 43,852,000 | $ (1,617,044,000) | $ (1,660,896,000) |

Sources:
Case No. U-18124, Exhibit A-1 (JRF-1) and Exhibit A-7 (JRF-37), Schedule A-1
Case No. U-18424, Exhibit A-1 (JRC-1) and Exhibit A-11 (JRC-1), Schedule A-1
Case No. U-20322, Exhibit A-1 (AGV-1) and Exhibit A-11 (JRC-37), Schedule A-1
Case No. U-20650, Exhibit A-1 (JRC-1) and Exhibit A-11 (JRC-38), Schedule A-1
Case No. U-21148, Exhibit A-1 (HLR-1) and Exhibit A-11 (HLR-27), Schedule A-1
Case No. U-21308, Exhibit A-1 (HLR-1) and Exhibit A-11 (HLR-28), Schedule A-1
Case No. U-21490, Exhibit A-1 (HLR-1) and Exhibit A-11 (HLR-28), Schedule A-1

What this shows is that even under Consumers' own numbers, it would not have been able to seek the large rate increases it has sought in seven out of its eight most recent rate cases, including this proceeding, but for basing its requested rate increases on projected test years. To put it another way, the use of a projected test year allows Consumers to begin recovery of costs before those costs have been verified as being real and prudently incurred. This has had and continues to have several adverse impacts on customers.

First, it has caused and continues to cause customers to experience rate increases sooner than they would under the use of a historical test year.

Second, it has eliminated and continues to eliminate the incentive for Consumers to contain costs that would otherwise exist due to the regulatory lag effect associated with the use of a historical test year.

Third, it has allowed and continues to allow Consumers to fill its projections with proposed capital expenditures and expenses that either Consumers has not irrevocably committed to making or otherwise can avoid if it finds it advantageous to do so to improve its realized ROR for its shareholders. This can allow the Company to collect revenue from its customers for capital expenditures or expenses it does not ultimately incur or has not yet incurred when rates are placed into effect. This unreasonably benefits shareholders at the expense of Consumers' customers.

Finally, the use of a projected test year greatly handicaps the Staff and intervenors in reviewing Consumers' rate filings to ensure the projected capital expenditures and expenses are reasonable because they are not actual capital expenditures and expenses reflected on the Company's books, but rather projections developed over many separate cost subaccounts and revenue categories. This requires much more time and greater resources than are necessary in a rate proceeding that utilizes a historical test year, all while the rate case timing has been compressed down to a 10-month time frame. As a result, while some inappropriate cost projections by Consumers may be identified and successfully disallowed as a result of Staff and intervenor review of Consumers' projections, many other inappropriate cost projections may be missed and inappropriately included in the Company's rates at the expense of its customers as I have outlined above.

**Q ARE CONSUMERS' PROJECTED BRIDGE PERIOD CAPITAL EXPENDITURES AND FORECASTED TEST YEAR EXPENSES AND CAPITAL EXPENDITURES KNOWN AND MEASURABLE CHANGES TO ITS HISTORICAL TEST YEAR?**

A No, they are not. Known and measurable changes are changes to costs that are inescapable and precisely identifiable in amount and timing. Future capital expenditures and projected expenses are often not inescapable, not precisely identifiable in amount and timing, or both. When they are escapable or not precisely identifiable with respect to amount and timing, they are not known and measurable changes from the historical test year. Furthermore, many of the capital expenditures and expenses that Consumers has attempted to recover in past general rate cases and is attempting to recover in this current proceeding, as shown by the Direct Testimony of my colleague, Mr. Fitzhenry, are highly speculative, and others have not been adequately supported. These include capital expenditures and expenses that Consumers has not irrevocably committed to make. These too are not known and measurable changes from the historical test year.

**Q PLEASE PROVIDE SOME EXAMPLES OF CHANGES FROM A HISTORICAL TEST YEAR THAT ARE KNOWN AND MEASURABLE CHANGES.**

A Examples of valid known and measurable changes to historical test year amounts include:

- Normalization to address the effects of volatility, such as those related to economic conditions or weather, and unusual events such as extended forced generation outages that distort the amounts that fall within the historical test year;

- Annualization to address costs, such as those associated with nuclear generation refueling outages and other types of extended planned generation outages, that regularly occur on a periodic basis, but not in every year;

- Costs that only occurred during the later months of the historical test year and are expected to continue at that same level on a going forward basis; and

- Imminent changes in costs that will occur during the period between the end of the historical test period and the date new base rates go into effect and are expected to continue on a going forward basis.

**Q IS THERE ANY EVIDENCE THAT SUGGESTS THAT CONSUMERS HAS BEEN MORE THAN FAIRLY COMPENSATED AS A RESULT OF BEING ALLOWED TO USE A PROJECTED TEST YEAR?**

A Yes. As my Table JAY-2 shows, in its rate filing in this proceeding, Consumers has reported a revenue sufficiency of approximately $9.4 million for its historical test year. This means that, in that historical test year (calendar year 2023), Consumers received revenues $9.4 million higher than necessary to earn its authorized ROR during that historical test year. In addition, in six out of seven of the Company's previous gas rate filings, it reported a revenue sufficiency for its historical test year and in four of those, the sufficiency was large, falling between $17.7 million and $35.3 million depending on the filing.

It is also important to note that the historical test year values presented in my Table JAY-2 are Consumers' reported historical test year values. If these historical test year values were closely examined, they might very well reveal costs that are not recoverable in rates. As a result, Consumers' actual revenues in excess of its authorized ROR in its historical test year for this proceeding (calendar year 2023) may very well have been well in excess of the approximately $9.4 million Consumers has reported. For example, as discussed in Mr. Fitzhenry's Direct Testimony, Consumers spent nearly $16 million more than forecasted on three Asset Relocation projects in the historical test year, and provided little explanation to support the cost variances.[2]

[2]Details are included in Section IIB of ABATE witness Colin Fitzhenry's Direct Testimony.

**Q IS THE COMMISSION REQUIRED TO SET RATES USING A PROJECTED TEST YEAR?**

A No. As the Commission discussed in its November 2, 2009 Order in Case No. U-15645, page 8, Section 6a(1) of Act 286, MCL 460.6a(1), provides that a utility "may use projected costs and revenues for a future consecutive 12-month period" to develop its requested rates and charges. The Commission added that the Staff and intervenors should direct their focus "upon the strengths and weaknesses of the evidentiary presentations of the parties regarding specific expense and revenue projections." In a case where a utility decides to base its filing on a fully projected test year, however, the utility bears the burden to substantiate its projections.[3] Recognizing the statutory time constraints present in a base rate case, the Commission has directed utilities to include all evidence (or sources of evidence) in support of their test year projections in their initial rate case filings.[4] If the utility cannot or will not provide sufficient support for a particular revenue or expense item (particularly for an item that substantially deviates from the historical data), "the Commission may choose an alternative method for determining the projection."[5] That alternative method should be the use of the historical test year amount for that item adjusted for only known and measurable changes to the amount for that item.

**Q WHAT DO YOU RECOMMEND TO THE COMMISSION WITH RESPECT TO THIS ISSUE?**

A Given the Company's track record with respect to its use of a projected test year, and the Commission's invitation to reconsider its approach to evaluating rate case

[3] *In re Detroit Edison Application for Rate Increase*, MPSC Case No. U-15768, January 11, 2010 Order at page 9.
[4] *Id*.
[5] *Id*.

applications as exemplified in its opening of the U-21637 docket, my primary recommendation is that the Commission reject Consumers' proposed use of a projected test year in this proceeding and reject Consumers' request for a rate increase in this proceeding.

**Q IF, DESPITE YOUR RECOMMENDATION, THE COMMISSION ALLOWS CONSUMERS TO USE A PROJECTED TEST YEAR IN THIS PROCEEDING, WHAT DO YOU INSTEAD RECOMMEND TO THE COMMISSION?**

A If, despite my recommendation, the Commission decides to allow Consumers to use a projected test year for this proceeding, I have a near-term recommendation and one longer-term recommendation, discussed further below, that the Commission should instead adopt.

First, I recommend the Commission be much more vigilant with respect to ensuring the expenses and investments being projected by Consumers for its projected test year are truly expenses and investments that are necessary to provide reliable service at the lowest reasonable cost. The Commission should also ensure that Consumers is irrevocably committed to incur its projected expenses and investments or otherwise cannot avoid them. Finally, the Commission should ensure that Consumers' projected investments and expenses are precisely quantified with respect to both amount and the specific quarter in which Consumers will incur these investments and expenses. It is clear from the recent track record of Consumers reporting historical test year revenues significantly in excess of its authorized return in several recent gas rate proceedings, as shown in Table JAY-2, that it is likely to some extent either questionable projections of Consumers are not being caught by intervenors and/or Staff in their review of the Company's proposals given the

complexity of verifying those projections, the Commission has provided too great of a benefit of doubt to Consumers with respect to the costs found to be questionable by intervenors and/or Staff, Consumers is not actually incurring the costs it has projected, or some combination of the three has been occurring. Consumers will essentially continue to earn a ROR higher than authorized by the Commission unless and until this issue is brought under control. It is very important the Commission make progress in this regard in order to ensure Consumers does not continue to abuse its use of a projected test year.

**Q WHAT IS YOUR LONGER-TERM RECOMMENDATION TO THE COMMISSION?**

A ABATE recommended in its May 14, 2021 and August 11, 2021 filed Comments in Case No. U-18238 that, as part of reconvening a collaborative work group to discuss the experience and impact of the rate case filing requirements set forth in its July 31, 2017 Order in Case No. U-18238, the Commission should have the collaborative workgroup address the use of projected test years and utility ROE requests continuing to result in excess revenue collection from customers under the Commission's current minimum filing requirements.[6] As detailed in its May 14, 2021 Comments, the Commission should examine: (i) customer benefits and detriments that have resulted from the use of projected test years; (ii) conditions under which the Commission would reject the use of a projected test year; (iii) categories of expenses/revenues that are uniquely difficult to predict so as to render their inclusion in a projected test year inappropriate; (iv) minimum criteria to reasonably demonstrate a sufficient commitment by the utility to actually incur the expenses it projects; (v) length of time between the end of the historical test year and the beginning of the proposed

[6]Case No. U-18238, ABATE's May 14, 2021 Comments at page 1.

projected test year; (vi) a method of tracking projections for various costs to determine consistency and extent of over- or under-projection and potential projection guardrails or limits; and (vii) whether the use of a projected test year by a utility should factor into its authorized ROE. Further attention to these issues could help tailor and bolster the Filing Requirements and utility rate case applications to ensure that projected test year filings more accurately and reasonably align projections with utility revenue requirements.[7] While the Commission's August 11, 2022 Order in Case No. U-18238 did not adopt ABATE's recommendation, ABATE continues to urge the Commission to pursue resolution of these issues through a collaborative workgroup as reiterated in its September 27, 2024 filed Comments in Case No. U-21637.

## III. REVENUE APPORTIONMENT

**Q HAVE YOU REVIEWED THE COMPANY'S PROPOSED REVENUE ALLOCATION?**

A Yes. A comparison of the Company's Preferred CCOSS results to its proposed revenue apportionment is presented in Table JAY-3.

[7] *Id.* at 5-6.

**TABLE JAY-3**

**Consumers' Preferred CCOSS (Version 2) vs.**
**Proposed Revenue Apportionment ($000)**

| Line | Rate Schedule | Delivery Revenues at Current Rates[1] (1) | Increase / (Decrease) to Reach Cost of Service[2] Amount (2) | Percent (3) | Index (4) | Consumers Proposed Increase / (Decrease)[1] Amount (5) | Percent (6) | Index (7) |
|---|---|---|---|---|---|---|---|---|
| 1 | Residential[3] | $1,110,994 | $201,968 | 18.2% | 1.13 | $195,779 | 17.6% | 1.10 |
| 2 | GS-1[3] | 172,968 | 14,530 | 8.4% | 0.52 | 16,171 | 9.3% | 0.58 |
| 3 | GS-2[3] | 131,566 | 2,882 | 2.2% | 0.14 | 7,432 | 5.6% | 0.35 |
| 4 | GS-3[3] | 28,958 | 2,184 | 7.5% | 0.47 | 1,037 | 3.6% | 0.22 |
| 5 | ST | 34,864 | 11,149 | 32.0% | 1.99 | 11,814 | 33.9% | 2.11 |
| 6 | LT | 27,199 | 7,080 | 26.0% | 1.62 | 7,765 | 28.5% | 1.78 |
| 7 | XLT | 30,204 | 7,334 | 24.3% | 1.51 | 7,923 | 26.2% | 1.64 |
| 8 | XXLT | 10,129 | 882 | 8.7% | 0.54 | 87 | 0.9% | 0.05 |
| 9 | Total | $1,546,883 | $248,008 | 16.0% | 1.00 | $248,008 | 16.0% | 1.00 |

Sources and Notes:

[1] Exhibit No. A-16 (SAS-1), Schedule F-2, page 2.

[2] Exhibit No. A-16 (SMG-2), Schedule F-1.1.

[3] Proposed revenues include incremental late payment revenue totaling $498,000 from WP-SAS-2.

As shown in column (4) of the table, the Company's Preferred CCOSS would result in increases well above the system average for Rate ST, Rate LT, and Rate XLT, due to the flawed P&A methodology. While Consumers' proposed revenue apportionment is generally based on the results of its Preferred CCOSS, the proposed revenue apportionment actually increases the revenue requirement for Rate ST, Rate LT, and Rate XLT above the level indicated by the flawed CCOSS. On the other hand, the Company's proposed revenue allocation mitigates the increase that would be required for the Residential, GS-3, and Rate XXLT classes to reach cost of service based on Consumers' Preferred CCOSS.

**Q IS THE COMPANY'S PROPOSED SPREAD OF THE REVENUE DEFICIENCY REASONABLE?**

A No. The Company's proposed revenue apportionment and rate design are based on the results of an inaccurate CCOSS, and do not sufficiently reflect an equitable revenue apportionment. As discussed below in greater detail, the Company's CCOSS does not allocate T&D main capacity costs in accordance with the load characteristic that drives Consumers' investment in T&D main capacity. A CCOSS based on the Design Day Demand method of capacity cost allocation would be the most accurate based on cost-causation. However, given the Commission's preference for a partial energy weighting allocation method, a reasonable alternative would be to rely on the Company's AED (Version 3) CCOSS.

**Q ARE YOU RECOMMENDING AN ALTERNATIVE REVENUE APPORTIONMENT?**

A Yes. My recommended revenue apportionment would be as shown in Table JAY-4.

**TABLE JAY-4**

**Alternative Revenue Apportionment ($000)**

| Line | Rate Schedule | Delivery Revenues at Current Rates[1] (1) | Consumers Proposed Increase / (Decrease)[1] Amount (2) | Percent (3) | Index (4) | ABATE Proposed Increase / (Decrease) Amount (5) | Percent (6) | Index (7) |
|---|---|---|---|---|---|---|---|---|
| 1 | Residential[2] | $1,110,994 | $195,779 | 17.6% | 1.10 | $200,560 | 18.1% | 1.13 |
| 2 | GS-1[2] | 172,968 | 16,171 | 9.3% | 0.58 | 16,171 | 9.3% | 0.58 |
| 3 | GS-2[2] | 131,566 | 7,432 | 5.6% | 0.35 | 7,432 | 5.6% | 0.35 |
| 4 | GS-3[2] | 28,958 | 1,037 | 3.6% | 0.22 | 3,192 | 11.0% | 0.69 |
| 5 | ST | 34,864 | 11,814 | 33.9% | 2.11 | 8,681 | 24.9% | 1.55 |
| 6 | LT | 27,199 | 7,765 | 28.5% | 1.78 | 5,154 | 18.9% | 1.18 |
| 7 | XLT | 30,204 | 7,923 | 26.2% | 1.64 | 5,195 | 17.2% | 1.07 |
| 8 | XXLT | 10,129 | 87 | 0.9% | 0.05 | 1,624 | 16.0% | 1.00 |
| 9 | Total | $1,546,883 | $248,008 | 16.0% | 1.00 | $248,008 | 16.0% | 1.00 |

Sources and Notes:

[1] Exhibit No. A-16 (SAS-1), Schedule F-2, page 2.

[2] Proposed revenues include incremental late payment revenue totaling $498,000 from WP-SAS-2.

My recommended revenue spread considers both the Company's proposed revenue allocation (based on the results of the P&A CCOSS Version 2) and the results of the AED CCOSS (Version 3), and also reflects a more equitable distribution of the claimed revenue deficiency than proposed by the Company. My recommended revenue allocation makes a gradual but meaningful movement toward cost of service, and ensures that no class receives an increase greater than 1.6 times the system average.

**Q WHAT IS THE BASIS FOR YOUR RECOMMENDATION TO ALLOW THE AED CCOSS TO INFORM REVENUE ALLOCATION AND RATE DESIGN?**

A I recommend allowing the AED CCOSS to inform the revenue spread and rate design in this case because it more accurately reflects cost-causation on the Company's

system than the P&A method, while satisfying the Commission's preference to recognize a volumetric component in the allocation of demand-related costs. However, I do not recommend a sole strict reliance on the AED CCOSS, and instead recommend it be used as a guide to how revenue responsibility should be apportioned through the revenue allocation and rate design in this case, thus, reflecting a more equitable revenue apportionment than proposed by the Company.

**Q HAS THE COMMISSION CONSIDERED THE RESULTS OF MULTIPLE CCOSS IN SETTING RATES FOR OTHER GAS UTILITIES?**

A Yes. In DTE Gas Company's most recent rate case (Case No. U-21291), Staff's proposed rate design was informed by both the Company's P&A CCOSS and its Alternate CCOSS,[8] with the objective of moving toward a more rational distribution of revenue responsibility, particularly for the transportation rate schedules.[9] The Commission ultimately adopted the Staff's rate design recommendations.[10]

Allowing the AED CCOSS to inform rate design in this case would accomplish the same objective. That is, it would move classes toward a more rational revenue allocation based on a more accurate measure of class cost of service.

**Q IS YOUR PROPOSED REVENUE ALLOCATION CONSISTENT WITH THE COMPANY'S STATED RATE DESIGN OBJECTIVES?**

A Yes. The Company states that it has generally designed rates based on the results of its Preferred CCOSS, and indicates that its rate design goals are: (i) establishing rates that promote efficient use of the gas system and energy efficiency; (ii) establishing rates

[8]Case No. U-21291, Direct Testimony of Madison Todd at page 6, lines 15-16.
[9]Case No. U-21291, Direct Testimony of Nicholas Revere at page 7, lines 9-23 through page 8, lines 1-3.
[10]Case No. U-21291, Order dated November 27, 2024 at pages 235-236.

that promote a favorable business climate; and (iii) designing rates to provide the Company with a fair opportunity to collect its revenue requirement.[11] My recommended revenue allocation, which considers the AED CCOSS, accomplishes these objectives.

**Q WHAT IS THE IMPACT OF YOUR PROPOSAL ON THE RESIDENTIAL CLASS?**

A As shown in Table JAY-5 (in Section IV of my testimony), the difference between the Company's Preferred CCOSS (Version 2) and the AED CCOSS (Version 3) for the Residential class is minimal. However, my proposed increase for the Residential class is 1.13 times the system average increase instead of Consumers' proposed increase of 1.10 times the system average. My recommendation moves Residential revenues halfway between the level indicated by the Company's Preferred CCOSS and the AED CCOSS. At the Company's claimed revenue deficiency, this difference equates to about $0.23 per Residential customer per month.[12] To the extent the Commission approves a system average increase lower than the amount requested by Consumers, the impact would be less. For example, if the Commission approves two-thirds of the Company's requested increase, the impact would be about $0.16 per Residential customer per month.

## IV. CONSUMERS' CCOSS

**Q PLEASE DESCRIBE THE COMPANY'S CCOSS MODELS IN THIS CASE.**

A The Company has provided three CCOSS models in this case, which are sponsored by Mr. Samuel M. Geller. The Version 1 CCOSS employs methodologies previously approved by the Commission in Case No. U-20650, updated for the financial

[11]Direct Testimony of S. Austin Smith at page 4, lines 7-12.

[12]($200.6 million – $195.8 million) / 1,709,595 customers / 12 months = $0.23 / customer / month.

information in this case.[13] The Version 2 CCOSS (Consumers' Preferred CCOSS) relies on the P&A allocation of T&D capacity costs, but also incorporates three modifications that are responsive to issues raised in the previous rate case, Case No. U-21490.[14] Specifically, the Company's CCOSS Version 2 reflects the following modifications:

1. Removes Asset Retirement Costs ("ARC" or the Asset Retirement Obligation "ARO") from the calculation of Other Distribution Plant;

2. Breaks out and allocates Other Distribution Plant by Federal Energy Regulatory Commission ("FERC") account, consistent with the Settlement Agreement in Case No. U-21490; and

3. Breaks out and separately allocates Customer Care Center ("CCC") and Business Customer Care ("BCC") expenses. The Preferred CCOSS is consistent with the allocation methods that have been previously approved by the Commission.[15]

In addition, the Company has provided a Version 3 CCOSS for informational purposes as agreed upon in the Settlement Agreement in Case No. U-21490. The Version 3 CCOSS replaces the P&A method with the AED method as recommended by ABATE in that case.[16]

**Q ARE THE COMPANY'S PROPOSED MODIFICATIONS TO THE CCOSS TO ADDRESS ISSUES RAISED IN THE PREVIOUS RATE CASE REASONABLE?**

A Yes. I generally support the Company's proposed modifications to the CCOSS to address the concerns raised by parties in the past.

[13]Direct Testimony of Mr. Geller at page 2, lines 20-22.
[14]*Id.* at lines 22-24.
[15]*Id.* at 3, lines 1-6.
[16]*Id.* at lines 9-11.

**Q PLEASE DESCRIBE THE P&A ALLOCATION METHOD.**

A The Company uses the P&A cost allocation method to allocate the costs of T&D main capacity across customer classes in its Version 1 and Version 2 CCOSS models.

The P&A allocation factor consists of a weighting of two system load characteristics: the Design Day Demand allocator (weighted by 1 minus the system load factor) and the Average Demand (or annual volume) allocator (weighted by the system load factor).

**Q ON WHAT BASIS HAS THE COMMISSION APPROVED THE P&A METHOD FOR ALLOCATING T&D MAIN COSTS IN PRIOR CASES?**

A The Commission's prior adoption of the P&A method has been based on the following:

1) A gas distribution system has to produce both peak day service and off-peak service to be economically viable.[17] Peak day load alone is insufficient to pay for the cost of building the plant.[18]

2) To focus only on the peak demand services that the system provides does not sufficiently account for how the system operates every other day of the year, when customers still expect the safe, reliable delivery of natural gas.[19]

**Q ARE THERE COST ALLOCATION METHODS OTHER THAN THE P&A THAT WOULD RESOLVE THE COMMISSION'S CONCERNS WITH THE DESIGN DAY DEMAND METHOD WHILE MORE ACCURATELY REFLECTING COST-CAUSATION?**

A Yes. For example, the AED method using each class's Non-Coincident Peak ("NCP") demand to determine the excess demand component would satisfy the Commission's objectives of setting rates based on sound cost-causation principles.

[17]Case No. U-18124, July 31, 2017 Final Order at page 114.
[18]*Id.*
[19]*Id.*

**Q ARE YOU RECOMMENDING THE COMMISSION RECONSIDER THE COST ALLOCATION METHOD IN THIS RATE CASE?**

A Respectfully, yes. I believe the Commission is supportive of setting rates based on sound cost-causation principles, while simultaneously managing customer class rate impacts. Therefore, first, I will discuss the load characteristics that truly drive Consumers' investment in T&D main capacity. Second, I will describe the AED methodology. Third, I will explain how the AED method reflects cost-causation on Consumers' system and meets the Commission's CCOSS objectives.

**Q DO YOU HAVE ANY OTHER COMMENTS ON WHY YOU RECOMMEND THE COMMISSION RECONSIDER ITS PRIOR POSITIONS ON THE P&A METHOD?**

A Yes. The Company claims that its rate design objectives include establishing rates that promote efficient use of the gas system, and rates that promote a favorable business climate.[20] However, establishing rates based on the flawed and inaccurate P&A allocation method undermines this objective.

In addition, large energy intensive customers, such as ABATE members, are aware of the cost allocation methods used in Michigan as compared to other jurisdictions. In order to remain competitive within their industries and across the jurisdictions in which they operate, these customers make investment decisions based on that knowledge. Thus, it is important to note that other jurisdictions have adopted cost allocation methods that more accurately measure each class's cost of service than the P&A method. Examples include Georgia,[21] Manitoba,[22] Missouri, and Pennsylvania

[20]Direct Testimony of S. Austin Smith at page 4, lines 9-11.

[21]The Georgia Public Service Commission's February 14, 2020 Order in Docket No. 42315 approved the Design Day Demand method for Atlanta Gas Light Company.

[22]The Public Utilities Board of Manitoba, Canada's October 12, 2022 Final Order in Centra Gas Manitoba's rate case found that the P&A method was not reflective of cost-causation, as the system is designed to meet Design Day Demand. Manitoba Board Final Order, available at:

to name a few. Missouri and Pennsylvania are discussed in greater detail later in this testimony.

## A. Load Characteristics that Drive Investment in T&D Main Capacity

**Q PLEASE EXPLAIN HOW CONSUMERS DESIGNS ITS T&D SYSTEM.**

A Gas local distribution companies design and size their T&D systems based on the peak demands of their customers, including the hour of maximum demand. Consumers is no different.

**Q HOW DOES THE COMPANY DEFINE PEAK DAY DESIGN REQUIREMENT?**

A The peak day design requirement, also referred to as a design peak day, is the total maximum daily load for all natural gas customers that Consumers would expect to serve under the most extreme cold weather conditions, as explained in the Direct Testimony of Company witness Joseph McDonnell, page 13, lines 14-19 in Case No. U-21437 (attached as Exhibit AB-2). Throughout my testimony, I will refer to this peak day design requirement as Design Day Demand.

**Q WHAT EVIDENCE HAS CONSUMERS PROVIDED TO CONFIRM IT DESIGNS ITS T&D MAINS TO MEET DESIGN DAY DEMAND?**

A Consumers has provided multiple discovery responses supporting the fact that T&D main capacity is designed to meet system peak demand (i.e., Design Day Demand).

http://www.pubmanitoba.ca/v1/proceedings-decisions/orders/pubs/22-orders/109-22.pdf (last visited April 16, 2025); see also *Centra Gas Manitoba Inc. - 2021 Cost of Service Study*, Public Utilities Board of Manitoba, docket available at: http://www.pubmanitoba.ca/v1/proceedings-decisions/appl-current/centra-2021-coss.html (last visited April 16, 2025).

The specific evidence is summarized below, and included in Consumers' discovery responses attached as Exhibit AB-1.

1) The system is designed so that the Company can provide continued service during times of peak demand on the system.[23]

2) The Company does not design mains to meet average demand.[24]

3) Hydraulic modeling is used to ensure the system can meet operational objectives including maintaining deliveries to customers throughout the entire year, including design peak day conditions.[25]

4) The Company does not use load factor to determine the facilities required.[26]

5) The Company agreed that an asset designed just to meet average demand could face challenges in providing reliable service if demand exceeds the average.[27]

**Q WHY DOES THE COMPANY RELY ON THE PEAK DAY DESIGN REQUIREMENT FOR CAPACITY PLANNING PURPOSES?**

A The objective of using Design Day Demand for capacity planning is to ensure sufficient supply under extreme and potentially dangerous cold conditions,[28] which protects the Company's ability to serve its customers under all other conditions when load is less than the Design Day Demand requirement.

[23]Consumers' Response to Discovery Request U21806-AB-CE-0476. Attached as Exhibit AB-1 at page 1.

[24]Consumers' Response to Discovery Requests U21806-AB-CE-0477, U21806-AB-CE-0482. Attached as Exhibit AB-1 at pages 2-3.

[25]Consumers' Response to Discovery Requests U21806-AB-CE-0482, part a., and U21806-AB-CE-0483, part b. Attached as Exhibit AB-1 at pages 3-5.

[26]Consumers' Response to Discovery Request U21806-AB-CE-0484. Attached as Exhibit AB-1 at page 6.

[27]Consumers' Response to Discovery Request U21806-AB-CE-0487. Attached as Exhibit AB-1 at pages 7-10.

[28]Case No. U-21437, Direct Testimony of Joseph McDonnell at page 19, lines 17-19. Included as Exhibit AB-2.

**Q THE COMPANY EXPLAINS THAT THE PRIMARY PURPOSE OF ITS T&D MAINS IS TO MEET ALL CUSTOMER DEMANDS FOR NATURAL GAS AT ALL TIMES. IF T&D MAINS WERE DESIGNED TO MEET AVERAGE DEMAND, WOULD THIS PRIMARY OBJECTIVE BE ACCOMPLISHED?**

A No. If T&D main capacity was designed to meet average demand, then the Company would not be able to provide firm service on days when demand exceeds the average. In this scenario, the Company would fail to achieve its objective of meeting all customer demands for natural gas at all times. However, if mains are designed to serve Design Day Demand (which they are), then it follows that the Company can meet all customer demands at all other times when demand is less than the Design Day Demand. It is clear that Design Day Demand is the driver of T&D main capacity and provides the Company with the ability to achieve its stated purpose of meeting all customer demands for natural gas at all times.

**Q WHAT IS THE PRIMARY DRIVER OF CONSUMERS' SYSTEM PEAK DEMAND?**

A Weather, specifically outside air temperature, is the primary driver of natural gas demand. The Company's 2025 – 2035 Natural Gas Delivery Plan confirms this, as it states that Michigan's winter demand peaks are due to residential heating and, therefore, significantly affected by weather conditions.[29]

**Q ARE THERE OTHER FACTORS THAT CONFIRM THAT SYSTEM PEAK DEMAND IS THE CAUSE OF INVESTMENT IN T&D MAIN CAPACITY?**

A Yes. Once this capacity is installed, the costs are fixed and do not change for any amount of gas flowing through the system – whether that is a peak day or any other

[29]Exhibit No. A-42 (NPD-1), page 22.

day. Absent the addition of new customers or a change in system design day requirements, the cost of mains will not change regardless of changes in annual throughput that result from weather and conservation.

Further, consider an example in which Consumers serves two customers with the same Design Day Demand requirements from identical distribution mains (i.e., same material, diameter, installed cost). However, one customer's annual throughput is twice as much as the other's. Thus, the demand-related cost to serve each customer is the same. However, each customer would be allocated a different amount of those capacity costs if an annual throughput allocator is used. Specifically, the customer with greater annual throughput (i.e., the higher load factor customer) would be allocated a greater share of capacity costs than the other customer. The use of a throughput allocator effectively penalizes the higher load factor customer for its more efficient utilization of the installed distribution main capacity. This is contrary to the objective of setting rates based on sound cost-causation principles.

**Q PLEASE SUMMARIZE YOUR CONCLUSIONS REGARDING THE LOAD CHARACTERISTICS THAT DRIVE INVESTMENT IN T&D MAINS.**

A The Company has clearly demonstrated that its T&D main capacity is designed to meet the natural gas demand of all ratepayers at all times. The only way to accomplish this service objective is to install T&D main capacity that meets Design Day Demand. Thus, from a cost-causation standpoint, Design Day Demand is the most appropriate capacity allocator to use in the CCOSS.

**Q ARE YOU RECOMMENDING THE USE OF A DESIGN DAY DEMAND CCOSS IN THIS CASE?**

A No. While the Design Day Demand method is most accurate from a cost-causation standpoint, the Commission has expressed a preference for relying on a capacity allocator which includes an average demand component. The AED method would accommodate the Commission's preference, while more accurately reflecting cost-causation.

## B. AED CCOSS

**Q PLEASE DESCRIBE THE AED METHOD.**

A The AED method is similar to the P&A method, in that they both include a component based on average demand that is weighted by the utility's system load factor. Both methods also provide a measure of each class's peak demand. However, the two methods differ in the approach to determining the demand component, which results in the AED method being superior.

The demand component of the P&A allocator reflects each class's contribution to system peak day demand (i.e., coincident peak demand), which also includes the average demand. On the other hand, the AED allocator reflects the difference between each class's NCP demand and average demand (i.e., demand in excess of average demand), and as such does not suffer from the inherent flaw of double counting the average demand like the P&A method does.

Thus, the AED method assigns greater cost responsibility to gas deliveries that are more variable due to weather sensitivity or other factors. This is more reflective of cost-causation, as the excess T&D main capacity is held in reserve to meet the demand of weather-sensitive loads that spike on a peak day.

**Q IS THE AED METHOD MATHEMATICALLY EQUIVALENT TO THE DESIGN DAY DEMAND METHOD?**

A The AED method is not equivalent to the Design Day Demand method, as long as each class's NCP demand is used to develop the demand component of the allocation factor, rather than each class's contribution to system peak day demand.

**Q HAS CONSUMERS PROVIDED NCP DEMAND DATA FOR EACH CLASS IN THIS CASE?**

A Yes. Consumers has derived the customer class NCP values using each class's maximum monthly throughput, consistent with ABATE's recommendations in the prior rate case, Case No. U-21490.[30]

**Q DOES CONSUMERS BELIEVE THE AED METHOD IS REASONABLE?**

A Yes. Company witness Mr. Geller states that the AED method is reasonable and makes some improvements to the P&A method.[31]

**Q FROM THE COMPANY'S PERSPECTIVE, WHAT IMPROVEMENTS DOES THE AED METHOD MAKE RELATIVE TO THE P&A METHOD?**

A The Company stated that the P&A method calculates peak demand inclusive of average demand volumes, while the AED method only considers the amounts of each rate class's peak demand over and above its average demand.[32] The Company

[30]Direct Testimony of Mr. Geller at page 11, lines 13-19.
[31]*Id.* at 12, lines 2-3.
[32]Consumers' Response to Discovery Request U21806-AB-CE-0475. Attached as Exhibit AB-1 at page 11.

confirmed that the AED method avoids the double counting of average demand that exists in the P&A method.[33]

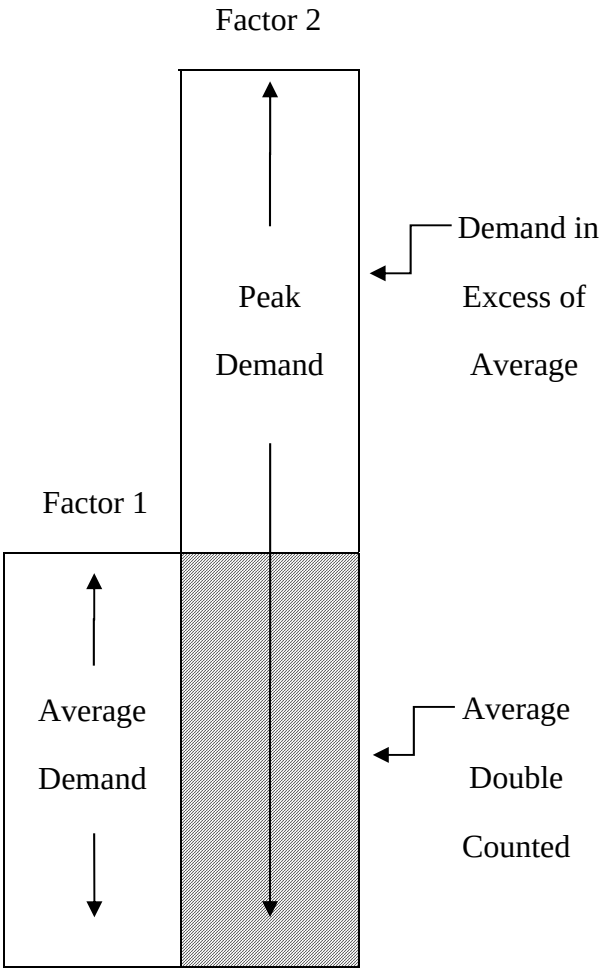
**Q YOU MENTIONED THAT THE P&A METHOD DOUBLE COUNTS AVERAGE DEMAND. CAN YOU PLEASE ILLUSTRATE THIS?**

A Yes. Average Demand is counted twice in the cost allocation: once in the Average Demand component and again in the Design Day Demand component.

This is represented graphically in Diagram 1. The Average Demand (Factor 1) is weighted by the system Load Factor ("LF"). Peak demand (Factor 2) is weighted by (1 – LF). The two weighted demands are added together to arrive at the P&A allocation factor. As a result, arithmetically, Average Demand receives a full weight of 1, while demand in excess of the average is weighted less than 1 (i.e., by (1 – LF)).

[33] *Id.*

**Peak and Average Method**




Peak and Average =

(LF x Factor 1) + (1 – LF) x Factor 2

**Diagram 1**

Diagram 1 illustrates the two steps in the process of calculating the P&A factors, the first of which is to determine the Average Demand component. The double counting of Average Demand occurs in the next step of the process where each class's

contribution to the system's Peak Demand is determined. In this second step, the P&A method considers the entire Peak Demand, including the Average Demand.

**Q ARE YOU AWARE OF ANY OTHER JURISDICTIONS THAT HAVE AGREED THAT THE AED METHOD RESOLVES THE ISSUE OF DOUBLE COUNTING AVERAGE DEMAND?**

A Yes. In PECO Energy Gas's 2020 base rate case, the Pennsylvania Public Utility Commission ("Pennsylvania Commission") approved the utility's proposed AED cost allocation method, and cited the issue of double counting as evidence for support of the AED methodology. Specifically, the Pennsylvania Commission stated the following:

> "Moreover, we are also persuaded by PECO's argument regarding the implicit double counting of Average Demand in the P&A methodology. Again, the AED methodology allocates mains costs based, in part, on Average Demand, and, in part, on the portion of Peak Demand that exceeds Average Demand. Alternatively, mains costs are allocated under the P&A methodology based, in part, on Average Demand, and, in part, on the total Peak Demand. Consequently, Average Demand is included in the Average Demand component and in the Peak Demand component, which includes Average Demand. Accordingly, due to residential customers having temperature sensitive demand and corresponding low-load factors, double-counting Average Demand understates the residential cost of service while overstating the cost of service of more efficient gas users."[34]

In addition, the Missouri Public Service Commission on several occasions has found that the double counting of Average Demand in the P&A method is a flaw. The Missouri Public Service Commission in its May 28, 2010 Order, at page 85 for Case No. ER-2010-0036, an AmerenUE electric rate case, found that:

> "The Peak and Average method, in contrast, initially allocates average costs to each class, but then, instead of allocating just the excess of the peak usage period to the various classes to the cost causing classes, the method reallocates the entire peak usage to the classes that contribute to the peak. Thus, the classes that contribute a large amount to the average usage of the system but add little to the peak, have their

[34]Case No. R-2020-3018929, June 22, 2021 Opinion and Order, at pages 229-230.

average usage allocated to them a second time. Thus, the Peak and Average method double counts the average system usage, and for that reason is unreliable."[35]

In 2011, the Missouri Public Service Commission again found the P&A method to be unreliable in Case No. ER-2011-0028,[36] and rejected the use of the P&A method in Case No. ER-2014-0258[37] because of the double counting of Average Demand.

**Q DOES THE AED (VERSION 3 CCOSS) INCLUDE THE MORE GRANULAR ALLOCATION OF DISTRIBUTION PLANT, BCC, AND CCC EXPENSES AS WAS REFLECTED IN THE COMPANY'S PREFERRED CCOSS (VERSION 2)?**

A Yes. This change is reasonable, regardless of which CCOSS is used.

## C. The AED Method Resolves the Commission's Concerns with a Pure Demand Method

**Q HOW DO THE RESULTS OF THE AED CCOSS COMPARE TO THE P&A CCOSS?**

A A comparison of the P&A and AED CCOSS results are presented in Table JAY-5.

[35]Missouri Public Service Commission Report and Order available at: https://efis.psc.mo.gov/Document/Display/81315 (last visited April 16, 2025).

[36]Missouri Public Service Commission Report and Order dated July 23, 2011 at pages 114-115. https://efis.psc.mo.gov/Document/Display/76964 (last visited April 16, 2025).

[37]Missouri Public Service Commission Report and Order dated April 29, 2015 at pages 70-71. https://efis.psc.mo.gov/Document/Display/101982 (last visited April 16, 2025).

**TABLE JAY-5**

**Comparison of CCOSS Results ($000)**
**Consumers' Preferred (Version 2) vs. AED (Version 3)**

| Line | Rate Schedule | Delivery Revenues at Current Rates[1] (1) | Version 2 CCOSS Increase / (Decrease) to Reach Cost of Service[2] Amount (2) | Percent (3) | Index (4) | Version 3 CCOSS Increase / (Decrease) to Reach Cost of Service[3] Amount (5) | Percent (6) | Index (7) |
|---|---|---|---|---|---|---|---|---|
| 1 | Residential[3] | $1,110,994 | $201,968 | 18.2% | 1.13 | $199,152 | 17.9% | 1.12 |
| 2 | GS-1[3] | 172,968 | 14,530 | 8.4% | 0.52 | 15,340 | 8.9% | 0.55 |
| 3 | GS-2[3] | 131,566 | 2,882 | 2.2% | 0.14 | 903 | 0.7% | 0.04 |
| 4 | GS-3[3] | 28,958 | 2,184 | 7.5% | 0.47 | 4,200 | 14.5% | 0.90 |
| 5 | ST | 34,864 | 11,149 | 32.0% | 1.99 | 13,828 | 39.7% | 2.47 |
| 6 | LT | 27,199 | 7,080 | 26.0% | 1.62 | 6,208 | 22.8% | 1.42 |
| 7 | XLT | 30,204 | 7,334 | 24.3% | 1.51 | 5,116 | 16.9% | 1.06 |
| 8 | XXLT | 10,129 | 882 | 8.7% | 0.54 | 3,261 | 32.2% | 2.01 |
| 9 | Total | $1,546,883 | $248,008 | 16.0% | 1.00 | $248,008 | 16.0% | 1.00 |

Sources and Notes:
[1] Exhibit No. A-16 (SAS-1), Schedule F-2, page 2.
[2] Exhibit No. A-16 (SMG-2), Schedule F-1.1.
[3] Exhibit No. A-54 (SMG-3), page 1.

As shown in the table, the AED CCOSS produces similar results as the Company's Preferred CCOSS for the Residential class, but shows that closer-to-system average increases are needed to bring Rate LT and Rate XLT to cost of service.

**Q DOES THE AED METHOD RECOGNIZE THAT THE UTILITY PROVIDES BOTH PEAK DAY SERVICE AND OFF-PEAK SERVICE, CONSISTENT WITH LANGUAGE CITED IN THE COMMISSION'S ORDER IN CASE NO. U-18124?**

A Yes. The AED method distinguishes between the amount of capacity needed to serve base or average load, and the amount of capacity needed to serve peak demand that

exceeds average demand. The cost of that capacity is spread over annual billing determinants and recovered from customers throughout the year.

**Q DOES THE AED METHOD ASSIGN CAPACITY COSTS TO CUSTOMERS IN A MANNER THAT REFLECTS HOW THE SYSTEM OPERATES TO PROVIDE SAFE, RELIABLE DELIVERY OF NATURAL GAS EVER DAY OF THE YEAR?**

A Yes. The Company incurs the cost of mains to meet the aggregate demand of its customers on the expected day of its greatest system demand. The Company acknowledged that its system peak demand is primarily driven by weather-sensitive customer classes who use natural gas for space heating. Through the use of the excess demand component of the allocator, the AED method assigns greater cost responsibility to gas deliveries that are more variable due to weather-sensitivity or other factors. Relative to the P&A method, the AED method is more reflective of cost-causation on Consumers' system, as the excess T&D main capacity is held in reserve to meet the demand of weather-sensitive loads that spike on a peak day.

**Q DOES THE AED METHOD PRODUCE FAIR AND REASONABLE RESULTS?**

A Yes. Relative to the P&A method, the AED method more closely reflects how the system is designed and used. Thus, the results are fair and reasonable, and more accurately reflect cost-causation on Consumers' gas system.

**Q PLEASE SUMMARIZE YOUR RECOMMENDATIONS WITH RESPECT TO CAPACITY COST ALLOCATION IN THE COMPANY'S CCOSS.**

A The evidence provided by Consumers makes clear that Design Day Demand is the load characteristic that drives investment in capacity to provide safe, reliable firm

service to customers on the peak day and all other days throughout the year. Thus, from a cost-causation standpoint, Design Day Demand would produce the most accurate measure of the Company's cost of providing service to each rate class.

However, to the extent that the Commission prefers to continue relying on a partial energy-weighted method, then the AED approach is more accurate and reasonable than the P&A method for the reasons I have described. Therefore, as noted above, I recommend allowing the AED CCOSS to inform the revenue spread and rate design in this case to more accurately reflect cost-causation on the Company's system, while satisfying the Commission's preference to recognize a volumetric component in the allocation of demand-related costs, and reflecting a more rational and equitable revenue apportionment for the cost allocation adopted in this proceeding.

## V. TRANSPORTATION RATE DESIGN

**Q HAS THE COMPANY IDENTIFIED ITS OBJECTIVES FOR RATE DESIGN IN THIS CASE?**

A Yes. The Company states that it has generally designed rates based on the results of its Preferred CCOSS, and indicates that its rate design goals are: (i) establishing rates that promote efficient use of the gas system and energy efficiency; (ii) establishing rates that promote a favorable business climate; and (iii) designing rates to provide the Company with a fair opportunity to collect its revenue requirement.[38]

[38]Direct Testimony of S. Austin Smith at page 4, lines 7-12.

**Q PLEASE DESCRIBE THE COMPANY'S RATE DESIGN FOR THE TRANSPORTATION RATE SCHEDULES.**

A The Company's transportation rates include Rates ST, LT, XLT, and XXLT. Customers may choose the service category under which they take service, provided that to qualify for Rate XXLT, a customer must have a minimum annual throughput of 4 million Mcf and must operate at an Authorized Tolerance Level ("ATL") of 4% or less.

The transportation rate structure consists of principal customer charges, contiguous customer charges, and volumetric distribution charges.[39] The rates differ between service categories.

**Q HOW HAS THE COMPANY DEVELOPED ITS PROPOSED TRANSPORTATION RATES IN THIS CASE?**

A The principal customer charges for Rate ST and Rate XXLT are set based on the results of the Company's Preferred CCOSS (Version 2), and the principal customer charges for Rates LT and XLT are set to maintain the existing economic breakeven points.[40] This results in customers' charges for Rates LT and XLT being less than the customer charge indicated by the Company's CCOSS by 5% and 7%, respectively.[41]

The volumetric distribution charge is designed to recover the remaining portion of each transportation rate schedule's allocated revenue requirement.

[39]Direct Testimony of S. Austin Smith at page 11, lines 5-7.
[40]*Id.* at lines 7-9.
[41]Consumers' Response to Discovery Request U21806-AB-CE-0495, part f. Included as Exhibit AB-1 at page 12.

**Q DOES THE COMPANY'S PROPOSED RATE DESIGN FOR TRANSPORTATION CUSTOMERS ALIGN WITH THE RESULTS OF ITS PREFERRED CCOSS?**

A Not entirely. As noted above, the principal customer charges for Rate ST and Rate XXLT are tied to the Company's Preferred CCOSS. However, the remaining rate design reflects shifts in revenue requirement between the Transportation rate schedules in order to maintain existing economic breakeven points.

**Q PLEASE EXPLAIN THE CONCEPT OF ECONOMIC BREAKEVEN POINTS.**

A The Company defines the economic breakeven point as the point of volumetric usage where revenue collected from one rate would equal revenue collected on a different rate.[42]

**Q WHAT IS THE COMPANY'S RATIONALE FOR DESIGNING TRANSPORTATION RATES TO MAINTAIN ECONOMIC BREAKEVEN POINTS?**

A The Company claims that maintaining breakeven points allows for greater precision in revenue prediction and, therefore, greater accuracy in setting rates, and minimizing confusion for customers.[43] The Company wishes to prevent rate shifting, because if customers frequently shift from rate to rate on a large scale, this could create revenue volatility for the Company.[44]

[42]Direct Testimony of S. Austin Smith at page 11, lines 18-19.
[43]*Id.* at 12, lines 5-6.
[44]*Id.* at lines 6-10.

**Q WHAT DOES THE COMPANY MEAN WHEN IT REFERS TO FREQUENT SHIFTS FROM RATE TO RATE?**

A In response to a discovery request, the Company indicated that the reference to "frequent shifts from rate to rate" means a circumstance in which a customer switches rate schedules every time the Company receives a rate order.[45]

**Q DO YOU AGREE WITH THE COMPANY'S RATIONALE FOR USING ECONOMIC BREAKEVEN POINTS?**

A No. The Company has not provided evidence to show that frequent rate shifting and revenue volatility would occur if rates for all Transportation rate schedules were based on the CCOSS rather than a desire to maintain economic breakeven points. Indeed, minimal rate shifting has occurred over the last several years. In addition, the Company's tariff provides that after a transportation customer selects a rate under which it will take service, the customer shall not be permitted to change from that rate to another rate until at least 12 months have elapsed.[46] Further, the greatest level of transportation customer rate switching in recent years occurred in 2024 (despite no change in economic breakeven points),[47] and involved 87 Rate LT customers. However, the Company was not negatively affected by this rate switch, as it experienced an approximate $37 million revenue sufficiency in 2024. This calculation is attached as Exhibit AB-3.

[45]Consumers' Response to Discovery Request U21806-AB-CE-0495, part a. Included as Exhibit AB-1 at page 12.

[46]Consumers' Tariff Sheet No. C-19.00, Section C4.2, Choice of Rates.

[47]Consumers' Response to Discovery Request U21806-AB-CE-0495, parts b-e. Included as Exhibit AB-1 at page 12.

**Q HAS THE COMPANY PROVIDED INSIGHT ON HOW MANY TRANSPORTATION CUSTOMERS HAVE SWITCHED RATES OVER THE LAST FEW YEARS?**

A Yes. Table JAY-6 shows the annual number of transportation customers that left each service category each year. For example, the table shows that 1 customer switched from Rate ST to another Transportation rate schedule in 2020, and 3 customers switched from Rate XLT to another Transportation rate schedule in 2023.

**TABLE JAY-6**

**No. of Transportation Customers that Left Each Service Category from 2020 through 2025 YTD**

| Line | Description | ST (1) | LT (2) | XLT (3) | XXLT (4) |
|---|---|---|---|---|---|
| 1 | CY 2020 | 1 | 5 | 3 | 0 |
| 2 | CY 2021 | 2 | 0 | 0 | 0 |
| 3 | CY 2022 | 0 | 0 | 0 | 0 |
| 4 | CY 2023 | 1 | 0 | 3 | 0 |
| 5 | CY 2024 | 1 | 87 | 0 | 0 |
| 6 | CY 2025 | 0 | 0 | 0 | 0 |
| 7 | Test Year Customer Count | 1,282 | 359 | 128 | 3 |

Sources and Notes:
[1] U-21806-AB-CE-0495, included in Exhibit AB-1.
[2] TY no. of customers is from Exhibit A-15 (MA-11).
[3] For example, 1 ST customer switched from ST to another transportation rate schedule in CY 2020.

While the table shows that 87 customers switched from Rate LT to another Transportation rate schedule in 2024, this did not negatively affect Consumers as the Company experienced a significant revenue sufficiency of about $37 million that year.

**Q IS SHIFTING REVENUES BETWEEN TRANSPORTATION RATE SCHEDULES TO MAINTAIN BREAKEVEN POINTS CONSISTENT WITH THE COMPANY'S RATE DESIGN OBJECTIVES?**

A No. The Company claims that revenue is shifted to promote rate stability and to moderate rate impacts.[48] However, it is unclear how rate impacts are moderated by a transportation rate design that produces class average rate increases ranging from 26% to 34% (or up to 2 times the system average) for the ST, LT and XLT classes.

**Q ARE YOU RECOMMENDING AN ALTERNATIVE TRANSPORTATION RATE DESIGN?**

A Yes. I recommend that the principal customer charges for the transportation rate schedules be set based on the Company's AED CCOSS, the distribution charges are set to recover the remaining portion of the class revenue requirements shown in Table JAY-4, and that the breakeven points be recalculated accordingly. My recommended transportation rate design is shown in Exhibit AB-4. My recommended rate design reflects the Company's claimed revenue deficiency, and would need to be modified based on the final revenue requirement approved by the Commission.

**Q DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?**

A Yes, it does.

[48]Consumers' Response to Discovery Request U21806-CB-CE-0494. Included as Exhibit AB-1 at page 14.

## Qualifications of Jessica A. York

**Q PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.**

A Jessica York. My business address is 16690 Swingley Ridge Road, Suite 140, Chesterfield, MO 63017.

**Q PLEASE STATE YOUR OCCUPATION.**

A I am a consultant in the field of public utility regulation and a Principal with the firm of BAI, energy, economic and regulatory consultants.

**Q PLEASE IDENTIFY THE JURISDICTIONS IN WHICH YOU HAVE PREVIOUSLY SPONSORED TESTIMONY.**

A I have sponsored expert testimony in front of the Idaho Public Utilities Commission, the Illinois Commerce Commission, Indiana Utility Regulatory Commission, the Iowa Utilities Commission, the Kansas Corporation Commission, the Michigan Public Service Commission, the Minnesota Public Utilities Commission, the Missouri Public Service Commission, the Public Utilities Commission of Nevada, the Oklahoma Corporation Commission, the Virginia State Corporation Commission, and the Public Service Commission of Wisconsin.

**Q PLEASE STATE YOUR EDUCATIONAL BACKGROUND AND PROFESSIONAL EMPLOYMENT EXPERIENCE.**

A I graduated from Truman State University in 2008 where I received my Bachelor of Science Degree in Mathematics with minors in Statistics and Actuarial Science. I earned my Master of Business Administration Degree with a concentration in Finance from the University of Missouri-St. Louis in 2014.

I joined BAI in 2011 as an analyst. Then, in March 2015, I joined the consulting team of BAI.

I have worked in various electric, natural gas and water and wastewater regulatory proceedings addressing cost of capital, sales revenue forecasts, revenue requirement assessments, class cost of service studies, rate design, and various policy issues. I have also conducted competitive power and natural gas solicitations on behalf of large electric and natural gas users, have assisted those large power and natural gas users in developing procurement plans and strategies, assisted in competitive contract negotiations, and power and natural gas contract supply administration. In the regulated arena, I have evaluated cost of service studies and rate designs proffered by other parties in cases for various utilities, including in Idaho, Illinois, Indiana, Kansas, Wisconsin and others. I have conducted bill audits, rate forecasts and tariff rate optimization studies.

I have also provided support to clients with facilities in deregulated markets, including drafting supply requests for proposals, evaluating supply bids, and auditing competitive supply bills. I have also prepared and presented to clients reports that monitor the electric market and recommend strategic hedging transactions.

BAI was formed in April 1995. BAI and its predecessor firm have participated in more than 700 regulatory proceedings in forty states and Canada.

BAI provides consulting services in the economic, technical, accounting, and financial aspects of public utility rates and in the acquisition of utility and energy services through RFPs and negotiations, in both regulated and unregulated markets. Our clients include large industrial and institutional customers, some utilities and, on occasion, state regulatory agencies. We also prepare special studies and reports, forecasts, surveys and siting studies, and present seminars on utility-related issues.

In general, we are engaged in energy and regulatory consulting, economic analysis and contract negotiation.

In addition to our main office in St. Louis, the firm also has branch offices in Corpus Christi, Texas; Louisville, Kentucky and Phoenix, Arizona.

**STATE OF MICHIGAN**
**BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION**

| | | |
|---|---|---|
| **In the matter of the application of CONSUMERS ENERGY COMPANY for authority to increase its rates for the distribution of natural gas and for other relief.** | ) | **Case No. U-21806** |

Rebuttal Testimony and Exhibits of

**Jessica A. York**

On behalf of

**Association of Businesses Advocating Tariff Equity**

May 14, 2025

BRUBAKER & ASSOCIATES, INC.

Project 11775

**STATE OF MICHIGAN**
**BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION**

| | | |
|---|---|---|
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**STATE OF MICHIGAN**
**BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION**

| | | |
|---|---|---|
| **In the matter of the application of CONSUMERS ENERGY COMPANY for authority to increase its rates for the distribution of natural gas and for other relief.** | ) | **Case No. U-21806** |

# Rebuttal Testimony of Jessica A. York

## I. INTRODUCTION

**Q PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.**

A Jessica A. York. My business address is 16690 Swingley Ridge Road, Suite 140, Chesterfield, MO 63017.

**Q ARE YOU THE SAME JESSICA A. YORK WHO PREVIOUSLY FILED TESTIMONY IN THIS PROCEEDING?**

A Yes. I filed Direct Testimony on behalf of the Association of Businesses Advocating Tariff Equity ("ABATE") on April 23, 2025. ABATE consists of large usage customers that purchase substantial amounts of natural gas and/or delivery service from Consumers Energy Company ("Consumers" or "Company").

**Q WHAT IS THE PURPOSE OF YOUR REBUTTAL TESTIMONY?**

A My Rebuttal Testimony will address certain recommendations made by the Michigan Public Service Commission ("MPSC" or "Commission") Staff ("Staff"), the Citizens Utility Board ("CUB"), and the Lansing Board of Water & Light ("LBWL") and Michigan State University ("MSU") (together "LBWL/MSU") regarding the Class Cost of Service

Study ("CCOSS"), revenue apportionment, and rate design. Specifically, I will respond to CUB witness Richard Bunch's and Staff witness Kevin Krause's recommendations regarding the allocation of uncollectible expense. In addition, I will comment on Staff witness Nicholas Revere's and LBWL/MSU witness Timothy Lyons' recommended allocation of Other Distribution Plant. Lastly, I will address Staff witness Nancy Rademacher's revenue apportionment and rate design recommendations for the transportation classes.

My silence with regard to any issue should not be construed as an endorsement of positions taken by other parties on that issue.

## II. ALLOCATION OF UNCOLLECTIBLE EXPENSE

**Q WHAT IS MR. BUNCH'S RECOMMENDATION REGARDING THE ALLOCATION OF UNCOLLECTIBLE EXPENSE?**

A Mr. Bunch takes issue with the Company's allocation of uncollectible expense. The Company allocated uncollectible expense based on a three-year average of net write-offs caused by customers served under each rate.[1] This approach allocates about 89% of uncollectible expense to the Residential class.[2] Mr. Bunch argues that uncollectible expense is a general cost of doing business, and that this category of expense should be allocated in proportion to Cost of Service plus Cost of Gas.[3]

[1]Direct Testimony of Richard Bunch at page 24, lines 9-11.
[2]*Id.* at lines 4-5.
[3]*Id.* at lines 16-17.

**Q WHAT IS STAFF WITNESS KRAUSE'S RECOMMENDATION REGARDING THE ALLOCATION OF UNCOLLECTIBLE EXPENSE?**

A Staff claims the Company's method of allocating uncollectible expense does not reflect the reality of the way uncollectible costs are incurred or how they should be borne by the classes.[4] Instead, Staff recommends allocating uncollectible expense based on revenue.[5]

**Q DO YOU AGREE WITH CUB'S AND STAFF'S RECOMMENDED ALLOCATION OF UNCOLLECTIBLE EXPENSES?**

A No. While uncollectible expense is a cost of doing business, it is clear from the Company's analysis of net write-offs (included in Exhibit CUB-3) that it is a cost of doing business with certain types of customers – primarily Residential. The Company tracks this data by rate schedule, and it is undeniable that the Residential customers have been responsible for nearly 90 percent of net write-offs each year from 2021 through 2023.[6] Indeed, Mr. Bunch even acknowledges that Residential uncollectible expense has increased 53.7% from 2021 to 2023.[7] On the contrary, the large transportation customers have been responsible for little to no net write-offs (or even net negative net write-offs) during that same three-year period.[8] There is no evidence to suggest that the Company's projected uncollectible expense will be driven by a different rate class in the future test year.

[4]Direct Testimony of Kevin Krause at page 6, lines 1-3.
[5]*Id.* at page 6, lines 5-7.
[6]Exhibit CUB-3.
[7]Direct Testimony of Richard Bunch at page 8, lines 5-6.
[8]Exhibit CUB-3.

**Q WOULD CUB'S AND STAFF'S PROPOSED ALLOCATION METHODS ASSIGN UNCOLLECTIBLE EXPENSE TO CLASSES FOR WHICH NO NET WRITE-OFFS WERE INCURRED?**

A Yes. For example, the Extremely Large Transportation ("XLT") and Extra Extremely Large Transportation ("XXLT") classes would receive an allocation of uncollectible expense under CUB's and Staff's proposals, despite not having caused any of this expense to be incurred by Consumers. Staff's and CUB's proposals would shift about $2.1 million and $2.5 million of projected uncollectible expense, respectively, to Non-Residential customers. This includes shifting approximately $460,000 of uncollectible expense to the Transportation class in excess of the amount allocated by the Company. This proposal is unjust, unreasonable, inconsistent with the National Association of Regulatory Utility Commissioners' ("NARUC") Electric Utility Cost Allocation Manual ("Manual") and should be rejected.

**Q PLEASE EXPLAIN HOW THE PROPOSALS OF CUB AND STAFF ARE INCONSISTENT WITH THE NARUC MANUAL.**

A First, the NARUC Manual notes that CCOSS models are used to attribute costs to different categories of customers based on how those customers cause costs to be incurred.[9] The NARUC Manual specifically discusses uncollectible expense in the chapter dedicated to the classification and allocation of customer-related costs, stating the following:

> Customer-related costs (Accounts 901-917) include the costs of billing and collection, providing service information, and advertising and promotion of utility services. By their nature, it is difficult to determine the "cause" of these costs by any particular function of the utility's operation or by particular classes of their customers. <u>An exception would be Account 904, Uncollectible Accounts. Many utilities monitor</u>

[9]January 1992 NARUC Manual at page 12.

> the uncollectible account levels by tariff schedule. Therefore, it may be appropriate to directly assign uncollectible accounts expense to specific customer classes.[10]

**Q DOES STAFF WITNESS KRAUSE ACKNOWLEDGE THAT CONSUMERS' PROPOSED ALLOCATION METHOD FOR UNCOLLECTIBLES IS THE ONE THAT IS CURRENTLY APPROVED?**

A Yes.[11]

**Q DOES THE COMPANY'S PROPOSED METHOD REFLECT THE REALITY OF THE WAY UNCOLLECTIBLE COSTS ARE INCURRED?**

A Yes. The Company tracks uncollectible expense by rate schedule and assigns this expense to the classes containing the customers that cause it.

**Q PLEASE SUMMARIZE YOUR CONCLUSIONS AND RECOMMENDATIONS REGARDING THE ALLOCATION OF UNCOLLECTIBLE EXPENSE.**

A The Company's method is reasonable as it keeps the uncollectible expense with the classes containing the customers that drive the expense, is consistent with the guidance of the NARUC Manual, and is the current approved method. The Company's proposed method of assigning uncollectible expense to rate classes should continue to be used.

[10] *Id.* at page 102.
[11] Direct Testimony of Kevin Krause at page 6, line 1.

## III. ALLOCATION OF OTHER DISTRIBUTION PLANT

**Q PLEASE SUMMARIZE LBWL/MSU'S RECOMMENDATION REGARDING THE ALLOCATION OF OTHER DISTRIBUTION PLANT.**

A LBWL/MSU witness Timothy Lyons recommends allocating Other Distribution Plant in Federal Energy Regulatory Commission ("FERC") Accounts 374, 375, 377, and 378 using Allocator 217 instead of Allocator 104 as proposed by the Company.[12] Allocator 217 represents a weighted average of Allocators 105 and 106 for High Pressure ("HP") and Non-HP distribution mains, respectively. Mr. Lyons believes that using Allocator 217 is a reasonable approach to first functionalize and then allocate distribution plant, recognizing the HP and Non-HP infrastructure used to provide service to the various classes.

**Q PLEASE SUMMARIZE STAFF'S RECOMMENDATION REGARDING THE ALLOCATION OF OTHER DISTRIBUTION PLANT.**

A Staff accepts the Company's proposed allocation (i.e., Allocator 104) of Other Distribution Plant in FERC Accounts 374, 375, and 377. However, Staff witness Revere recommends a more granular approach than the Company's to the allocation of Measuring and Regulator Stations plant in Account 378, considering the different pressure levels that this equipment serves.[13] The calculation of Staff's proposed allocator for Account 378 is shown on Staff's Exhibit S-21.0.

[12]Direct Testimony of Timothy Lyons at page 15, lines 4-5.
[13]Direct Testimony of Nicholas Revere at page 7, lines 8-21 through page 8, lines 1-5.

**Q DO YOU AGREE WITH THE PERSPECTIVE THAT THE ALLOCATION OF OTHER DISTRIBUTION PLANT SHOULD BE REFINED TO CONSIDER THE TYPES OF INFRASTRUCTURE INCLUDED IN EACH ACCOUNT, AND HOW THAT INFRASTRUCTURE IS USED (OR NOT USED) TO PROVIDE SERVICE TO EACH CLASS?**

A Yes. Upon further review of the Company's workpapers, I agree that it is reasonable to refine the allocation of Other Distribution Plant investment to more accurately recognize that certain classes, or certain customers within a class, are not served by Non-HP infrastructure. Further, this refinement would be reasonable whether the Average and Excess Demand ("AED") CCOSS or the Peak and Average ("P&A") CCOSS is used.

**Q HAVE YOU COMPARED STAFF'S CCOSS RESULTS TO THE AED CCOSS WITH STAFF'S MODIFIED ALLOCATION OF ACCOUNT 378, AND TO AN AED CCOSS WITH MR. LYONS' RECOMMENDED ALLOCATION OF OTHER DISTRIBUTION PLANT?**

A Yes. I have recalculated Staff's Account 378 allocator (shown on Exhibit AB-21) using the AED method, and applied it to the AED CCOSS (shown on Exhibit AB-22). I have also applied Mr. Lyons' recommended allocation of Other Distribution Plant to the AED CCOSS (shown on Exhibit AB-23). Table JAY-1-RT presents a comparison of these CCOSS results.

**TABLE JAY-1-RT**

**Staff's CCOSS vs. AED CCOSS ($000)**

| Line | Rate Schedule | Delivery Revenues at Current Rates[1] (1) | Staff's CCOSS Increase / (Decrease) to Reach Cost of Service[2] Amount (2) | Percent (3) | Index (4) | AED CCOSS[3] w/Staff ODP Alloc. Increase / (Decrease) Amount (5) | Percent (6) | Index (7) | AED CCOSS[4] LBWL/MSU ODP Alloc. Increase / (Decrease) Amount (8) | Percent (9) | Index (10) |
|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | Residential | $1,112,113 | $151,521 | 13.6% | 1.19 | $151,153 | 13.6% | 1.19 | $152,402 | 13.7% | 1.20 |
| 2 | GS-1 | 172,968 | 7,529 | 4.4% | 0.38 | 8,141 | 4.7% | 0.41 | 8,216 | 4.8% | 0.41 |
| 3 | GS-2 | 131,566 | (1,424) | -1.1% | (0.09) | (4,586) | -3.5% | (0.30) | (4,354) | -3.3% | (0.29) |
| 4 | GS-3 | 28,958 | 1,118 | 3.9% | 0.34 | 2,692 | 9.3% | 0.81 | 2,575 | 8.9% | 0.78 |
| 5 | ST | 34,864 | 9,480 | 27.2% | 2.37 | 11,856 | 34.0% | 2.97 | 11,671 | 33.5% | 2.92 |
| 6 | LT | 27,199 | 5,466 | 20.1% | 1.75 | 4,503 | 16.6% | 1.44 | 4,396 | 16.2% | 1.41 |
| 7 | XLT | 30,204 | 4,042 | 13.4% | 1.17 | 1,844 | 6.1% | 0.53 | 1,162 | 3.8% | 0.34 |
| 8 | XXLT | 10,129 | (383) | -3.8% | (0.33) | 1,748 | 17.3% | 1.51 | 1,283 | 12.7% | 1.11 |
| 9 | Total | $1,548,002 | $177,350 | 11.5% | 1.00 | $177,350 | 11.5% | 1.00 | $177,350 | 11.5% | 1.00 |

Sources and Notes:
[1] Exhibit No. S-6.0, Schedule F-2, page 2.
[2] Exhibit No. S-6, Schedule F-1.1.
[3] Reflects Staff's Account 378 allocator, and Company's allocation of uncollectibles.
[4] Reflects LBWL/MSU allocation of Other Distribution Plant ("ODP"), and Company's allocation of uncollectibles.

As shown in the table, there is not a significant difference for most classes, including Residential, between the AED CCOSS using Staff's proposed allocation of Account 378 as compared to an AED CCOSS using LBWL/MSU's allocation of Other Distribution Plant.

## IV. STAFF'S PROPOSED REVENUE APPORTIONMENT

**Q HAVE YOU COMPARED STAFF'S PROPOSED REVENUE APPORTIONMENT TO THE RESULTS OF ITS CCOSS, AT STAFF'S RECOMMENDED REVENUE DEFICIENCY?**

A Yes. A comparison of the results of Staff's CCOSS results to its proposed revenue apportionment is presented in Table JAY-2-RT.

**TABLE JAY-2-RT**

**Staff's CCOSS (Version 2) vs.**
**Proposed Revenue Apportionment ($000)**

| Line | Rate Schedule | Delivery Revenues at Current Rates[1] (1) | Staff's CCOSS Increase / (Decrease) to Reach Cost of Service[2] Amount (2) | Percent (3) | Index (4) | Staff Proposed Increase / (Decrease)[1] Amount (5) | Percent (6) | Index (7) |
|---|---|---|---|---|---|---|---|---|
| 1 | Residential[3] | $1,112,113 | $151,521 | 13.6% | 1.19 | $145,982 | 13.1% | 1.15 |
| 2 | GS-1[3] | 172,968 | 7,529 | 4.4% | 0.38 | 8,897 | 5.1% | 0.45 |
| 3 | GS-2[3] | 131,566 | (1,424) | -1.1% | (0.09) | 2,294 | 1.7% | 0.15 |
| 4 | GS-3[3] | 28,958 | 1,118 | 3.9% | 0.34 | 579 | 2.0% | 0.17 |
| 5 | ST | 34,864 | 9,480 | 27.2% | 2.37 | 10,081 | 28.9% | 2.52 |
| 6 | LT | 27,199 | 5,466 | 20.1% | 1.75 | 5,977 | 22.0% | 1.92 |
| 7 | XLT | 30,204 | 4,042 | 13.4% | 1.17 | 4,674 | 15.5% | 1.35 |
| 8 | XXLT | 10,129 | (383) | -3.8% | (0.33) | (1,135) | -11.2% | (0.98) |
| 9 | Total | $1,548,002 | $177,350 | 11.5% | 1.00 | $177,350 | 11.5% | 1.00 |

Sources and Notes:
[1] Exhibit No. S-6.0, Schedule F-2, page 2.
[2] Exhibit No. S-6, Schedule F-1.1.
[3] Proposed revenues include incremental late payment revenue totaling $356,000 from WP-NCR-2.

As shown in the table, Staff proposes to increase revenues for the Small Transportation ("ST"), Large Transportation ("LT"), and XLT rates such that they exceed the CCOSS result. For Rate XXLT, Staff proposes a rate decrease that is about three times larger than indicated by its CCOSS.

**Q DO YOU AGREE WITH STAFF'S RECOMMENDED REVENUE APPORTIONMENT?**

A No. Staff's proposed revenue apportionment for the transportation classes should be rejected. It is loosely based on the results of the P&A CCOSS, and does not consider the AED CCOSS. For the reasons explained in detail in my Direct Testimony, the P&A CCOSS method does not accurately assign costs to cost-causers based on the load characteristics that drive investment in the Company's Transmission and

Distribution ("T&D") main capacity. Thus, the P&A CCOSS should not be the only measure of class cost of service used to inform revenue distribution and rate design.

As noted above, Staff's proposed revenue apportionment for the transportation classes does not tie to the results of the underlying class cost of service. In addition, it would not be reasonable for Rate XXLT to receive a rate decrease nearly three times larger than indicated by the CCOSS, when other transportation classes are facing increases of twice the system average and larger.

**Q DID STAFF EXPLAIN THE RATIONALE BEHIND ITS PROPOSED REVENUE APPORTIONMENT?**

A Staff has not adequately explained the rationale for its proposed revenue distribution. Staff witness Rademacher simply states that Staff found that the rate stability targets used by the Company did not produce reasonable rate increases across the customer classes.[14] Ms. Rademacher further states that it decreased the stability target for GS-1 and GS-3 and increased the stability target for GS-2 until a reasonable rate design was attained.[15] Ms. Rademacher does not explain how Staff determined that the Company's rate stability targets were unreasonable, or why Staff's recommendations are reasonable.

**Q DO YOU CONTINUE TO RECOMMEND THAT REVENUE APPORTIONMENT AND RATE DESIGN BE INFORMED BY BOTH THE P&A CCOSS AND THE AED CCOSS?**

A Yes. As described in my Direct Testimony, the AED method would more accurately measure class cost of service than the P&A method and is more consistent with the

[14]Direct Testimony of Nancy Rademacher at page 5, line 20 through page 6, line 1.
[15]*Id.* at lines 1-5.

rationale described in prior Commission orders.[16] In addition, the Commission's prior adoption of the P&A method was based on the fact that the gas distribution system has to produce both peak day service and off-peak service to be economically viable, and that focusing only on peak day service does not sufficiently account for how the system operates every other day of the year.[17]

My interpretation of the Commission's rationale is that it intends for a capacity allocator to recognize that T&D capacity provides two separate and distinct services. First, a portion of total T&D capacity is used every day of the year to serve average daily demands (i.e., "throughput service"). Second, the additional T&D capacity that exists above the portion that provides throughput service provides a "reliability service." That is, there exists an amount of extra T&D capacity that is not needed unless daily demand exceeds the average, up to the yearly peak day demand on the system.

The amount of extra T&D capacity needed to provide "reliability service" is captured through the Excess Demand component of the AED allocator, and is calculated as the <u>difference</u> between each class's Non-Coincident Peak ("NCP") Demand and Average Demand. However, as shown in Diagram 1 of my Direct Testimony, mathematically, the P&A allocator does not capture the <u>difference</u> between Peak Demand and Average Demand. Thus, the P&A allocator does not recognize the distinction between the two services provided by T&D capacity.

The P&A allocator, unlike the AED allocator, allocates total system capacity to simultaneously serve average daily demands, and design peak day demands. Thus, the P&A allocator does not recognize how T&D capacity is designed to provide the separate and distinct "throughput service" and "reliability service."

[16]Direct Testimony of Jessica York at page 20, lines 10-16.
[17]*Id.*

**Q WHAT IS YOUR RECOMMENDATION WITH RESPECT TO THE CCOSS AND REVENUE APPORTIONMENT?**

A I continue to recommend that the distribution of any approved revenue deficiency be informed by the results of both the P&A CCOSS and the AED CCOSS, with the refinement to the allocation of Other Distribution Plant discussed earlier in my testimony. My recommended revenue apportionment based on Staff's claimed revenue deficiency, and with the more granular allocation of Other Distribution Plant, is shown in Table JAY-3-RT below.

**TABLE JAY-3-RT**

**Alternative Revenue Apportionment ($000)**

| Line | Rate Schedule | Delivery Revenues at Current Rates[1] (1) | Staff Proposed Increase / (Decrease)[1] Amount (2) | Staff Proposed Increase / (Decrease)[1] Percent (3) | ABATE Proposed Increase / (Decrease) Amount (4) | ABATE Proposed Increase / (Decrease) Percent (5) |
|---|---|---|---|---|---|---|
| 1 | Residential | $1,112,113 | $145,982 | 13.1% | $151,337 | 13.6% |
| 2 | GS-1 | 172,968 | 8,897 | 5.1% | 8,897 | 5.1% |
| 3 | GS-2 | 131,566 | 2,294 | 1.7% | 2,294 | 1.7% |
| 4 | GS-3 | 28,958 | 579 | 2.0% | 1,905 | 6.6% |
| 5 | ST | 34,864 | 10,081 | 28.9% | 6,191 | 17.8% |
| 6 | LT | 27,199 | 5,977 | 22.0% | 3,100 | 11.4% |
| 7 | XLT | 30,204 | 4,674 | 15.5% | 2,943 | 9.7% |
| 8 | XXLT | 10,129 | (1,135) | -11.2% | 683 | 6.7% |
| 9 | Total | $1,548,002 | $177,350 | 11.5% | $177,350 | 11.5% |

Sources and Notes:
[1] Exhibit No. S-6.0, Schedule F-2, page 2.

**Q WHAT IS THE IMPACT ON THE RESIDENTIAL CLASS OF YOUR RECOMMENDED REVENUE DISTRIBUTION RELATIVE TO STAFF'S PROPOSAL?**

A As shown in Table JAY-2-RT, Staff recommended an increase of 13.1 percent for the Residential class. My recommended revenue distribution produces a 13.6 percent increase for the Residential class. The difference between my proposal and Staff's

equates to about $0.27 per Residential customer per month.[18] Further, my recommended increase brings the Residential class rates in line with cost of service as measured by both the P&A and AED CCOSS models.

## V. ECONOMIC BREAKEVEN POINTS

**Q WHAT IS STAFF'S RECOMMENDATION REGARDING THE COMPANY'S ECONOMIC BREAKEVEN POINTS FOR THE TRANSPORTATION RATE SCHEDULES?**

A Staff witness Rademacher agrees with the Company's proposal to maintain the current economic breakeven points between the transportation rate schedules.[19] Staff argues that an effective breakeven point deters customers from switching rate classes, since being on another rate schedule would be more expensive.[20] Staff also states that if these breakeven points were changed without cause, or without properly reflecting such a change in the determinants, the Company's ability to collect its targeted revenue requirement would be inappropriately impaired.[21]

**Q DO RATES DEVIATE FROM THE UNDERLYING COST OF SERVICE WHEN BREAKEVEN POINTS ARE MAINTAINED?**

A Yes. In order to maintain the economic breakeven points between transportation rate schedules, the proposed customer charges for Rate LT and Rate XXLT deviate from cost of service. Thus, if rates are to be cost-based, there is cause to revise the economic breakeven points.

[18]($151.3 million - $146.0 million) / 1,709,595 customers / 12 = $0.27.
[19]Direct Testimony of Nancy Rademacher at page 6, lines 8-11.
[20]*Id.* at lines 15-17.
[21]*Id.* at lines 17-19.

**Q IS THERE EVIDENCE TO SUGGEST THAT THE COMPANY WOULD BE HARMED BY RATE SWITCHING IF THE ECONOMIC BREAKEVEN POINTS ARE CHANGED IN THIS CASE?**

A No. Indeed, despite some rate switching in recent years, the Company has continued to experience a revenue sufficiency nearly every year.[22]

**Q WHAT IS YOUR RECOMMENDATION REGARDING ECONOMIC BREAKEVEN POINTS FOR THE TRANSPORTATION RATE SCHEDULES?**

A I continue to recommend that the revenue distribution be informed by the results of both the P&A CCOSS and the AED CCOSS, that customer charges for the transportation rate schedules be set based on the AED CCOSS, that distribution charges be set to recover the remaining portion of the revenue requirement allocated to each class, and that the breakeven points be recalculated accordingly.

**Q DOES THIS CONCLUDE YOUR REBUTTAL TESTIMONY?**

A Yes, it does.

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[22]Direct Testimony of Jessica York at page 6 (Table JAY-2) and page 38.

MR. CAMPBELL: Mr. Fitzhenry's direct testimony consists of a cover page, a table of contents, 21 pages of questions and answers, an Appendix A setting out his qualifications, and along with his direct testimony, Mr. Fitzhenry sponsored Exhibit AB-5.

Mr. Fitzhenry's rebuttal testimony consists of a cover page, a table of contents, and four pages of questions and answers.

JUDGE VARCHETTI: All right. Are there any objections to the admission of Mr. Fitzhenry's testimony, direct and rebuttal, or the associated exhibit?

I am hearing none, so the testimony is bound into the record, and the exhibit is admitted.

MR. CAMPBELL: Thank you, Your Honor.

(Direct, Appendix A, and Rebuttal Testimony bound in)

**STATE OF MICHIGAN**

**BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION**

| | | |
|---|---|---|
| **In the matter of the application of CONSUMERS ENERGY COMPANY for authority to increase its rates for the distribution of natural gas and for other relief.** | ) ) ) ) ) ) ) | **Case No. U-21806** |

Direct Testimony and Exhibits of

**Colin T. Fitzhenry**

On behalf of

**Association of Businesses Advocating Tariff Equity**

April 23, 2025

BRUBAKER & ASSOCIATES, INC.

Project 11775

**STATE OF MICHIGAN**

**BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION**

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| **In the matter of the application of CONSUMERS ENERGY COMPANY for authority to increase its rates for the distribution of natural gas and for other relief.** | ) ) ) ) ) ) | **Case No. U-21806** |

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Appendix A: Qualifications of Colin T. Fitzhenry

Exhibit AB-5: Referenced Responses to Discovery Requests

**STATE OF MICHIGAN**

**BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION**

| | | |
|---|---|---|
| **In the matter of the application of CONSUMERS ENERGY COMPANY for authority to increase its rates for the distribution of natural gas and for other relief.** | ) | **Case No. U-21806** |

**Direct Testimony of Colin T. Fitzhenry**

# I. INTRODUCTION

**Q PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.**

A Colin T. Fitzhenry. My business address is 16690 Swingley Ridge Road, Suite 140, Chesterfield, MO 63017.

**Q WHAT IS YOUR OCCUPATION?**

A I am a consultant in the field of public utility regulation and an Associate with the firm of Brubaker & Associates, Inc. ("BAI"), energy, economic and regulatory consultants.

**Q PLEASE DESCRIBE YOUR EDUCATIONAL BACKGROUND AND EXPERIENCE.**

A This information is included in Appendix A to my testimony.

**Q ON WHOSE BEHALF ARE YOU APPEARING IN THIS PROCEEDING?**

A I am appearing on behalf of the Association of Businesses Advocating Tariff Equity ("ABATE"). ABATE consists of large usage customers that purchase substantial

amounts of electric power and/or delivery service from Consumers Energy Company ("Consumers" or "Company").

**Q WHAT IS THE PURPOSE OF YOUR DIRECT TESTIMONY?**

A My testimony will address Consumers' Capital and Operation and Maintenance ("O&M") expenditures.

My silence with respect to any position taken by Consumers in its Application or Direct Testimonies in this proceeding should not be interpreted as an endorsement of that position.

**Q PLEASE BRIEFLY SUMMARIZE YOUR CONCLUSIONS AND RECOMMENDATIONS IN THIS PROCEEDING.**

A My conclusions and recommendations are as follows:

- Current safety and reliability performance metrics indicate that the Company has above-average reliability and safety compared to other Michigan gas utilities. In addition, Consumers has demonstrated that it is able to improve safety and reliability by replacing legacy distribution mains at recent expenditure levels. I recommend that Consumers reduce the rate of replacement of natural gas mains in the near-term period unless a specific safety or reliability concern is identified.

- The Company completed 15% less miles of distribution main replacement in 2023 than originally projected. Further investment in the Companies' Enhanced Infrastructure Replacement Distribution Program ("EIRP – Distribution") would not likely yield customer benefits commensurate with the level of customer costs. I recommend the Company reduce capital expenditures in its EIRP - Distribution by $79.4 million in 2025 and $92.1 million in 2026 for a total of $171.1 million in its projected test periods.

- Consumers failed to demonstrate that $15.8 million in historical cost overruns for specific Asset Relocation projects were prudently incurred. The Company's explanations for these variances, which resulted in costs for three major projects more than doubling, provided inadequate justification. Therefore, it is recommended that the Commission disallow these specific cost variances, as the Company did not sufficiently show the excess costs were reasonable and that they were not the result of poor project management.

- The Company is requesting $1.3 million of O&M expense for the test year within the Leak Survey and Repair program to address an anticipated backlog of leak repairs. In addition, the company requests the ability to defer any test year O&M expenses resulting from the final Leak Detection and Repair ("LDAR") rule that exceed the requested funding. However, there is no need for increased funding currently, as historical data indicates a declining trend in the number of known system leaks requiring repair. The number of leaks scheduled for repair in 2023 was 27% below the recent five-year average. In addition, the funding request was linked to anticipated requirements from the new LDAR rule; however, this rule has not been finalized, and the compliance timelines assumed by the Company are no longer applicable based on the latest draft rule. The Commission should deny the Company's request for additional leak repair funding and the deferral of under-recovery of leak repair expenditures.

- I recommend Consumers use the Blue Chip GDP Chained Price Index for the O&M inflation factors. The non-labor inflation rates used by the Company are not well supported, and the Consumer Price Index for non-labor inflation rate is well above the consensus industry experts' opinion of the GDP Chained Price Index. In addition, the GDP Price Index has shown a stronger correlation with the change in cost of natural gas investments, such as natural gas meters, than the Consumer Price Index. This adjustment reduces the Company's projected O&M expenditures by $355,100.

## II. GAS DISTRIBUTION CAPITAL EXPENDITURES

**Q HAVE YOU REVIEWED THE COMPANY'S PROPOSED CAPITAL EXPENDITURES?**

A Yes. Company witness Lincoln D. Warriner supports the need for the Company's proposed gas distribution capital expenditures. The capital expenditures fall into four categories: (1) New Business; (2) Asset Relocation; (3) Regulatory Compliance; and (4) Capacity Deliverability. I have provided an overview of the Company's proposed capital expenditures in Table CTF-1 below.

**TABLE CTF-1**

**Summary of Proposed Distribution Capital Expenditures**
**($1,000s)**

| Description | Historical 12 mos. ended 12/31/2023 | Bridge Period 22 mos. ending 10/31/2025 | Projected Test 12 mos. ending 10/31/2026 | Total |
|---|---|---|---|---|
| New Business | $76,320 | $117,702 | $289,498 | $483,520 |
| Asset Relocation | 97,685 | 162,676 | 75,977 | $336,338 |
| Regulatory Compliance | 34,488 | 136,920 | 89,584 | $260,992 |
| Capacity/Deliverability | 4,446 | 14,512 | 10,240 | $29,198 |
| Total | $212,939 | $431,810 | $465,299 | $1,110,048 |

Source: Exhibit A-12 (LDW-1), Schedule B5.9

As can be seen from Table CTF-1, the Company is proposing to add approximately $1.1 billion in distribution capital investments over the rate case period. Asset Relocation and Regulatory Compliance make up over half of the Company's proposed capital expenditures. A large portion of these expenditures are related to the EIRP – Distribution, which I will address in greater detail below.

**Q PLEASE BRIEFLY DESCRIBE CONSUMERS' NATURAL GAS DISTRIBUTION SYSTEM.**

A Consumers operates approximately 30,700 miles of distribution and transmission pipelines and serves approximately 1.8 million natural gas customers.[1] The vast majority of the Company's distribution mains are comprised of plastic polyethylene (15,903 miles) and steel (12,351 miles), with only 179 miles of cast iron distribution mains remaining (less than one percent). In addition, Consumers operates about 1.6 million service mains, most of which are plastic (75%), followed by steel (18%) and copper (6%).[2] The vast majority of Consumers' distribution mains comprise material

[1] Myers Direct at 10.
[2] US DOT, PHSMA Form 7100, 2024.

types that are commonly used in modern natural gas distribution systems and have well-documented inertness to both the external soil environment and to natural gas.

**Q HAS THE COMPANY'S INVESTMENT IMPROVED THE SAFETY AND RELIABILITY OF ITS DISTRIBUTION SYSTEM?**

A Yes. According to the Company, over the last five years, Consumers has spent $4.7 billion on its gas system for safety, reliability, deliverability, system integrity, and customer service through its Natural Gas Delivery Plan ("NGDP").[3] This has resulted in a considerable reduction in the number of leaks in the Company's distribution system. Specifically, over the last five years (2020-2024) Consumers has reduced the average number of gas leaks per mile by approximately 30%.[4] I have shown a comparison of the number of leaks per mile for the five Michigan natural gas utilities reporting data to PHMSA in Table CTF-2 below.

**TABLE CTF-2**

**Gas Leaks Per Main Mile for Michigan Natural Gas Utilities**

| Utility Company | 2020 | 2024 | % Change |
|---|---|---|---|
| Consumers Energy Company | 0.033 | 0.023 | -30.0% |
| DTE Gas Company | 0.118 | 0.080 | -32.5% |
| SEMCO Energy Gas Company | 0.042 | 0.020 | -53.4% |
| Citizens Gas Fuel Company | 0.006 | 0.010 | 55.6% |
| Michigan Gas Utilities Company | 0.016 | 0.022 | 39.4% |
| Average | 0.043 | 0.031 | -4.2% |

Source: Annual Gas Distribution Report, PHMSA Form F-7100

[3] Dreisig Direct at 3.
[4] *See* Table CTF-2.

As can be seen from Table CTF-2, natural gas utilities in Michigan experienced on average 0.031 leaks per mile of main in 2024, or alternatively one leak for every 32 miles. Consumers' leak rate of 0.023 leaks per mile of main is about 25% less than the average of Michigan natural gas utilities reporting data to the Pipeline Hazardous Materials Safety Administration ("PHSMA").

**Q WHAT ARE THE MOST IMPORTANT CONTRIBUTING FACTORS WHEN CONSIDERING A NATURAL GAS UTILITY LEAK RATE?**

A When comparing a utility like DTE Gas Company ("DTE") to Consumers, you can see from Table CTF-2 that Consumers' distribution main leak rate is significantly less than DTE's. The primary driver in distribution main leaks is the condition of the main itself. Leak-prone materials such as cast iron, have a higher likelihood of developing leaks due to corrosion failure, which happens over a long period of time. Thus, it comes as no surprise that DTE has experienced 994 leaks due to corrosion failure in 2024 with 1,067 miles of cast iron main in operation, while Consumers has only experienced 146 leaks with 179 miles of cast iron main in operation.[5] As a result, DTE experienced about seven times more leaks due to corrosion failure in 2024 than Consumers, while having about six times more cast iron main in operation.

**Q ARE THE MAJORITY OF CONSUMERS' DISTRIBUTION MAIN LEAKS A RESULT OF CORROSION FAILURE?**

A No. I have shown the cause of Consumers' distribution main leaks in 2024 in Table CTF-3 below.

[5] US DOT, PHSMA Form 7100, 2024.

**TABLE CTF-3**

**Consumers Natural Gas Leaks by Type 2024**

| Description | Leaks | Percent of Total |
|---|---|---|
| Corrosion Failure | 146 | 22.2% |
| Natural Force Damage | 57 | 8.7% |
| Excavation Damage | 249 | 37.8% |
| Other Outside Force Damage | 5 | 0.8% |
| Pipe, Weld, or Joint Failure | 8 | 1.2% |
| Equipment Failure | 104 | 15.8% |
| Incorrect Operations | 11 | 1.7% |
| Other Cause | 78 | 11.9% |
| Total | 658 | 100.0% |

Source: Annual Gas Distribution Report, PHMSA Form F-7100

As can be seen from Table CTF-3, corrosion failure only accounts for 22.2% of the leaks in the distribution system. Damage caused by outside causes, such as natural force damage, excavation damage, and other outside force damage, accounts for 47.3% of all leaks, and the remaining 29.3% are the result of a combination of equipment failure, incorrect operations, and other causes. As a result, the majority of distribution main leaks in 2024 were unrelated to pipe corrosion failure (77.8%).

## IIA. Enhanced Infrastructure Replacement Distribution Program Expenditures

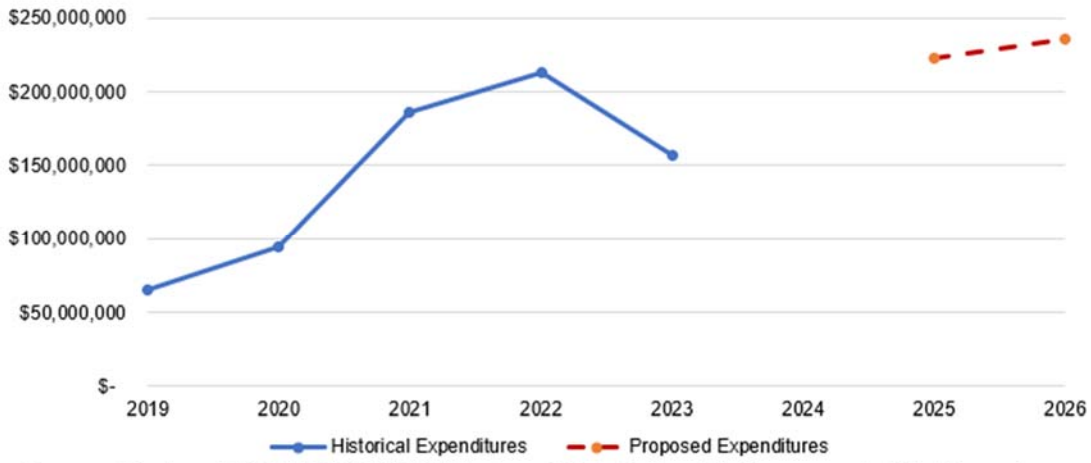
**Q IS THE COMPANY PROPOSING TO INCREASE ITS MAIN REPLACEMENT EXPENDITURES?**

A Yes. As part of its NGDP, the Company is proposing to spend $223 million in 2025 and $236 million in 2026 in its Enhance Infrastructure Replacement Program -

Distribution ("EIRP - Distribution").[6] This is a significant increase over the recent five-year historical average expenditures of approximately $143 million included in this program. I have shown a summary of these historical and proposed expenditures in Figure CTF-1 below.

**FIGURE CTF-1**

**Enhance Infrastructure Replacement Program - Distribution Historical and Proposed Expenditures**




Sources: Attachment "U21806-AB-CE-0457_Warriner_ATT_1.xlsx" provided in response to Data Request 21806-AB-CE-0457 (Historical Data) and "U21806-AB-CE-0466_Dreisig_ATT_1.xlsx" provided in response to Data Request 21806-AB-CE-0466 (Forecasted Data). Attached as Exhibit AB-5 at pages 1-4.
Note: Data for 2024 is not included becasue it is estimated.

As shown in Figure CTF-1, Consumers is proposing to continue to accelerate the rate of expenditures in its EIRP – Distribution program, despite demonstrating a significant reduction in leak rates at historical expenditure levels. Currently, only 0.63% of the Company's distribution system is composed of cast iron mains, which are more prone to leakage. In addition, the vast majority of the Company's distribution main leaks in 2024 were a result of issues unrelated to corrosion failure, which legacy main types such as cast iron main are susceptible to as well.

[6] Exhibit No. A-42 (NPD-1), Natural Gas Delivery Plan 2025-2035.

**Q HAS THE COMPANY DEMONSTRATED THAT THERE ARE EXCESSIVE SAFETY RISKS WITH ITS PROPOSED MAIN REPLACEMENT PROJECTS?**

A No. In response to Data Request U-21806-AB-CE-0467, attached as Exhibit AB-5 at page 5, the Company provided the top twenty-five highest risk distribution main segments according to probabilistic risk modeling. I have shown these projects along with their Risk Score and the year proposed for replacement in Table CTF-4 below.

**TABLE CTF-4**

**Top 25 Highest Risk Distribution Main Segments**

| Project | Plan Year | Rank | Risk Score |
|---|---|---|---|
| BCY2 Ph2 | 2026 | 1 | 28.3 |
| MAC12 Ph6 | 2025 | 2 | 18.3 |
| LIV4 Ph5 | 2025 | 3 | 17.4 |
| LIV4 Ph5 | 2025 | 4 | 14.9 |
| BCY2 Ph2 | 2026 | 5 | 10.0 |
| ROK12 Ph1 | 2026 | 6 | 8.3 |
| MAC11 Ph2 | 2026 | 7 | 7.9 |
| MDL2 Ph1 | 2025 | 8 | 7.8 |
| BCY3 Ph1 | 2025 | 9 | 6.9 |
| BCY2 Ph2 | 2026 | 10 | 6.7 |
| MAC13 Ph6 | 2026 | 11 | 6.6 |
| ROK16 Ph1 | 2025 | 12 | 6.0 |
| LAN5 Ph7 | 2024 | 13 | 5.9 |
| Civic project | 2025 | 14 | 5.0 |
| LAN12 | 2026 | 15 | 5.0 |
| LAN5 Ph4 | 2024 | 16 | 4.8 |
| LIV4 Ph5 | 2025 | 17 | 4.8 |
| KAL3 Ph8 | 2026 | 18 | 4.7 |
| Civic project | 2025 | 19 | 4.2 |
| MAC14 Ph2 | 2025 | 20 | 3.3 |
| MAC11 Ph2 | 2026 | 21 | 3.3 |
| LIV4 Ph5 | 2025 | 22 | 3.3 |
| SAG7 Ph1 | 2026 | 23 | 3.2 |
| JAC1 | 2025 | 24 | 2.8 |
| ROK6 Ph8 | 2024 | 25 | 2.8 |
| Average | | | 7.7 |

Source: Attachment "U21806-AB-CE-0467_Warriner_ATT_1.xlsx" included in Response to Data Request U21806-AB-CE-0467. Attached as Exhibit AB-5 at page 5.

As can be seen from Table CTF-4 only 8 of these top 25 risk distribution main segments have a Risk Score greater than the group average of 7.7. In addition, ten of the projects have a Risk Score of less than five. This demonstrates that the Company can

selectively replace only the highest risk distribution mains while continuing to improve safety and reliability.

**Q DID THE COMPANY COMPLETE AS MUCH EIRP – DISTRIBUTION WORK AS IT PROJECTED IN ITS 2023 HISTORICAL TEST YEAR?**

A No. In 2023, the Company replaced 108.9 miles of distribution main included in its EIRP – Distribution program. This is 19.0 miles less (15%), than the 128.0 miles projected in 2023. As a result, the Company incurred $68.1 million less capital expenditures than the $250 million projected.[7] If a similar pattern emerges in the Company's forecasted test periods, Consumers will spend less than the forecasted values it is requesting in this proceeding.

**Q WHAT IS YOUR RECOMMENDATION WITH RESPECT TO THE COMPANY'S PROPOSED EXPENDITURES IN THE EIRP – DISTRIBUTION PROGRAM?**

A The Company's current safety and reliability metrics do not support a need to increase the Company's expenditures in this program. Consumers can continue to complete main replacement projects at historical expenditure levels without burdening customers by accelerating investment. Furthermore, the Company has historically completed less work in the EIRP - Distribution program than originally forecasted. I recommend that the Company's proposed expenditure levels in its EIRP – Distribution program be reduced to the average historical expenditure level over the past five years ($143 million). This adjustment would reduce capital expenditures by $79.4 million in 2025 and $92.1 million in 2026 for a total of $171.1 million in its forecasted test periods.

[7] Attachment "U21806-AB-CE-0814_Warriner_ATT_1.xlsx" included in Response to Data Request U21806-AB-CE-0814. Attached as Exhibit AB-5 at pages 6-7.

## IIB. Asset Relocation Historical Test Year Expenditures

**Q PLEASE DESCRIBE THE HISTORICAL TEST YEAR ASSET RELOCATION EXPENDITURES.**

A The Asset Relocation Program includes gas distribution infrastructure replacement projects that are required due to civic improvement activities initiated by federal, state, or local governmental units, or by individual customers with existing gas service.[8] During the Company's historical test year, the Company incurred expenditures related to five asset relocation projects. I have summarized these projects in Table CTF-5 below.

**TABLE CTF-5**

**Asset Relocation Civic Improvement Distribution**
**Capital Expenditures Historical Test Year**
**($1,000s)**

| Description | Actual | Budget | Variance | % Variance |
|---|---|---|---|---|
| Mound Road Projects | $9,319 | $4,000 | $5,319 | 133.0% |
| Atlas Iron Belle Trail Project | 7,910 | 4,000 | 3,910 | 97.8% |
| 9 Mile Road Eastpointe | 10,623 | 4,000 | 6,623 | 165.6% |
| Prarie Drain | 0 | 1,500 | (1,500) | -100.0% |
| Other Projects | 55,666 | 59,082 | (3,416) | -5.8% |
| Total | $83,518 | $72,582 | $10,936 | 15.1% |

Source: Attachment "U21806-AB-CE-0814_Warriner_ATT_1.xlsx" provided in Response to Data Request U21806-AB-CE-0814. Attached as Exhibit AB-5 at pages 6-7.

As can be seen from Table CTF-5, the Company incurred capital expenditures approximately $11 million greater than budgeted amounts (15.1%). However, this variance is partially offset by a negative variance associated with the Prairie Drain project, because it was never completed, and "Other Projects", which represent a combination of smaller asset relocation projects. The three largest asset relocation

[8] Warriner Direct at 25.

projects with capital expenditures in 2023 were the Mound Road Projects, Atlas Irone Belle Trail Project, and the 9 Mile Road Eastpointe projects. All three of these projects had a combined cost variance of approximately $15.8 million, or an increase in cost of 132%.

**Q DID THE COMPANY PROVIDE AN EXPLANATION FOR THE SIGNIFICANT COST VARIANCE IN THESE ASSET RELOCATION PROJECTS?**

A Yes, the Company provided a limited explanation for the cost variances. I have provided the Company's full explanation for the cost variances for each of the projects below:[9]

1. Mound Road Projects: Variance due to scope changes by the county responsible for road construction; Heavy concrete restoration work also resulted in additional project cost.

2. Atlas Iron Belle Trail Project: Variance due to the initial estimate for the project being lower than the actual scope of work.

3. 9 Mile Road Eastpointe: Heavy concrete restoration work also resulted in additional project cost.

**Q DO THESE EXPLANATIONS JUSTIFY A MORE THAN DOUBLING OF COSTS WITH THESE PROJECTS?**

A No. Limited changes in project scope, additional concrete restoration work, and poor project estimates are not adequate justifications for these excessive cost increases.

[9] *See* Attachment "U21806-AB-CE-0814_Warriner_ATT_1.xlsx" provided in Response to Data Request U21806-AB-CE-0814 for cost variance explanations. Attached as Exhibit AB-5 at pages 6-7.

**Q WHAT IS YOUR RECOMMENDATION WITH RESPECT TO THESE ASSET RELOCATION PROJECTS WITH SIGNIFICANT COST VARIANCES?**

A I recommend the Commission disallow the $15.8 million of cost variances associated with these Asset Relocation projects. The Company has not adequately demonstrated the excess cost incurred to complete these projects was not the product of poor project management.

**Q WHY IS IT REASONABLE TO DISALLOW COST VARIANCES ASSOCIATED WITH PROJECTS THAT ARE IN SERVICE AND CONSIDERED USED AND USEFUL?**

A The rationale for using the cost variance in determining my proposed disallowance is to recognize that the project is in service and considered used and useful, but that a portion of the costs to place the project in service were imprudent. Specifically, the cost variance could represent excess project cost due to reasons such as extended project durations, poor project planning, labor cost overruns, or project scope creep. These would all be adequate explanations for a disallowance. In addition, with respect to the projects I have identified, the Company did not provide adequate explanations for the cost variances.

**Q WHAT IS THE ESTIMATED REVENUE REQUIREMENT IMPACT OF YOUR RECOMMENDED CAPITAL EXPENDITURES DISALLOWANCES?**

A At the Company's requested Return on Equity ("ROE"), the estimated revenue requirement impact is $7.2 million. At ABATE witness Mr. Walter's recommended ROE, the estimated revenue requirement impact is $6.2 million.

## III. GAS OPERATIONS O&M EXPENSE

**Q HAVE YOU REVIEWED THE COMPANY'S PROPOSED GAS OPERATIONS O&M EXPENSE?**

A Yes. The Company's Summary of its Gas Operations O&M Expense is included in Exhibit A-86 (JPP-1), sponsored by Company witness James P. Pnacek. The gas operations O&M expenditures fall into five categories: (1) Operations, Maintenance & Metering; (2) Field Operations Services; (3) Compliance & Controls; (4) Operations Performance; and (5) Operation Management. I have provided an overview of the Company's proposed Gas Operations O&M Expenditures in Table CTF-6 below.

**TABLE CTF-6**

**Summary of Proposed Gas Operations O&M Expenditures**
**($1,000s)**

| Description | 2023 Actuals | 2024 Projected | 2025 Projected | 12-Mos Ending 10/31/2026 |
|---|---|---|---|---|
| Operations, Maintenance & Metering | $86,376 | $89,946 | $96,190 | $107,391 |
| Field Operations Services | 19,031 | 19,033 | 18,407 | 22,037 |
| Compliance & Controls | 2,053 | 0 | 0 | 0 |
| Operations Performance | 3,005 | 2,320 | 2,502 | 2,539 |
| Operations Management | 834 | 1,701 | 1,643 | 1,668 |
| Total | $111,299 | $113,000 | $118,743 | $133,635 |

Source: Exhibit A-86 (JPP-1).

As can be seen from Table CTF-6, Consumers is requesting a projected test period gas operations O&M expense of approximately $133.6 million, a net increase of $22.3 million over the historical test period. I will discuss the Company's proposals with respect to the LDAR and the staking program, which have costs included in Gast Operations O&M expense in greater detail below.

## III.A. Leak Detection and Repair Rule

**Q PLEASE DESCRIBE THE LEAK DETECTION AND REPAIR RULE.**

A The company anticipates new regulations from the PHMSA implementing the Protecting the Infrastructure of Pipelines and Enhancing Safety Act of 2020 (PIPES Act). The goal is to reduce methane emissions from gas pipelines and storage facilities. These proposed amendments are referred to as the LDAR rules. The proposed rules introduce several key updates to gas system management. Leak detection efforts will be intensified through stronger survey and patrolling mandates, alongside performance standards for advanced detection programs. The criteria for grading leaks and the required timelines for repairing them are being modified. Measures to reduce emissions from blowdowns are included, as are updated rules for the design, configuration, and maintenance of pressure relief devices. Finally, the requirements for investigating system failures will be clarified, and reporting obligations will be expanded.[10]

**Q WHAT REQUIREMENTS ARE THE COMPANY ANTICIPATING COMPLYING WITH DURING THE TEST YEAR?**

A Consumers stated that PHMSA is proposing deadlines for operators to repair existing gas leaks identified before the new rule takes effect (expected July 2025). Operators would need to fix known Grade 2 leaks and any leaks on transmission lines in sensitive areas (High Consequence Areas, Class 3, or Class 4 locations) within one year of the final rule's publication, targeting completion by January 2026. For known Grade 3 leaks existing by the rule's effective date, the proposed repair timeframe is longer, requiring

[10] Pnacek Direct at 8.

completion within three years of the final rule's publication, with an expected compliance date of January 2028.[11]

**Q ARE THESE COMPLIANCE DATES STILL APPLICABLE BASED ON THE MOST RECENT DRAFT OF THE LDAR?**

A No. Based on new compliance timelines set forth in the most recently amended draft of the LDAR, which has yet to be published as a final rule, these dates are no longer applicable to the Company's test period.[12]

**Q WHAT ARE THE O&M EXPENDITURES THE COMPANY IS REQUESTING TO ADDRESS THE LDAR?**

A The Company is requesting $1.3 in funding for the test year within the Leak Survey and Repair program to address the anticipated leak backlog. In addition, the Company requests the ability to defer any test year O&M expenses resulting from the final rule that exceed the requested funding[13].

**Q ARE THESE REQUESTED EXPENDITURES REASONABLE GIVEN AMENDMENTS IN THE MOST RECENT DRAFT VERSION OF THE LDAR?**

A No. The final version of this rule has not been published, and the compliance dates anticipated by the Company based on the draft version of this rule are no longer applicable. The Company plans to withdraw its request for the Commission to approve the ability to defer any test year O&M expense that occurs as a result of the

[11] Pnacek Direct at 9.
[12] Response to Data Request U21806-AB-CE-0810, subpart a. Attached as Exhibit AB-5 at page 8.
[13] Pnacek Direct at 10.

requirements of the final rule, however, they are still proposing an increase of $1.3 million to address a leak backlog.[14]

**Q DOES HISTORICAL EVIDENCE SUPPORT THE COMPANY'S ASSERTION THAT THERE IS A BACKLOG OF LEAKS?**

A No. I have shown the number of known system leaks scheduled for repair in Table CTF-7 below.

**TABLE CTF-7**

**Known System Leaks Scheduled for Repair**

| Year | Main Leaks Repaired | Service Leaks Repaired | Total |
|---|---|---|---|
| 2019 | 987 | 7277 | 8264 |
| 2020 | 1173 | 9025 | 10198 |
| 2021 | 962 | 6453 | 7415 |
| 2022 | 859 | 5853 | 6712 |
| 2023 | 630 | 4971 | 5601 |
| Average | 922 | 6716 | 7638 |

Source: U21806-AB-CE-0456_Pascarello_Attachment_1 provided in Resonse to DR 21806-AB-CE-0456. Attached as Exhibit AB-5 at pages 9-12.

As can been from Table CTF-7, the number of known main and service leaks scheduled for repair in 2023 was well below the historical average. Specifically, the 5,601 known leaks in 2023 were 27% below the average number of main and service leaks over the last five years (2019-2023). Furthermore, this data demonstrates that the number of leaks has been declining.

[14] Response to Data Request U21806-AB-CE-0810, subpart b. Attached as Exhibit AB-5 at page 8.

**Q WHAT IS YOUR RECOMMENDATION WITH RESPECT TO THE COMPANY'S PROPOSAL TO INCREASE LEAK REPAIR O&M EXPENDITURES?**

A I recommend the Commission deny the Company's request for an additional $1.3 million of O&M expenditures to address leak repairs. The number of known main and service leaks has been declining, and the LDAR has not been finalized. Lastly, the Commission should deny the Company's request to defer any test year O&M expenses resulting from the final LDAR that exceed the requested funding.

## III.B. Inflation Factor

**Q PLEASE DESCRIBE THE INFLATION FACTORS CONSUMERS USED TO DEVELOP THE PROJECTED TEST PERIOD O&M EXPENSE.**

A The Company utilized the non-labor inflation factors published by S&P Global. The inflation factors in the June 2024 edition of S&P Global's U.S. Economic Outlook publication were 3.2% for 2024, 2.4% for 2025, and 2.5% for 2026.[15]

**Q DO YOU HAVE ANY CONCERNS WITH THE NON-LABOR INFLATION RATE USED BY THE COMPANY?**

A Yes. The Company uses the CPI (Consumer Price Index) to determine the appropriate non-labor inflation rate. I compared these proposed rates to the Blue Chip Economic Indicators industry GDP Chained Price Index over the same time period. The GDP chained price index uses a "chained" methodology. Each year, the basket of goods and services is updated to reflect what people are actually buying. This is unlike the CPI, which uses a fixed basket for a set period. This makes the GDP deflator more responsive to consumer substitution – if prices of certain goods rise, people might

[15] Rayl Direct at 12.

switch to cheaper alternatives, and the index will reflect that change. In addition, CPI can be heavily weighted by the cost of medical expenses, which is not reflective of the cost of utility expenses. The Blue GDP Chained Price Index is 2.4% for 2024, 2.6% for 2025, and 2.3% for the first three quarters of 2026.[16]

**Q DOES HISTORICAL EVIDENCE DEMONSTRATE THAT THE GDP PRICE INDEX HAS A STRONGER CORRELATION WITH THE PRICE OF GAS METERS THAN THE CONSUMER PRICE INDEX URBAN?**

A Yes. I have compared the actual cost per unit for gas meters over the 2020 through 2023 time period and then compared those change in costs to the GDP Price Index and Consumer Price Index – Urban. To make this comparison, I used a correlation function. The correlation function returns the correlation coefficient between two samples. Quite simply, a greater correlation coefficient represents a higher correlation between the two samples and a stronger relationship. I have provided the analysis of the correlation coefficient in Table CTF-8 below.

**TABLE CTF-8**

**Cost Per Gas Meter Compared to Historical CPI-U and GDP Price Index**
**($1,000s)**

| Description | 2020 | 2021 | 2022 | 2023 | Correlation |
|---|---|---|---|---|---|
| Actual Cost Per Unit[1] | -3.7% | 20.0% | 8.5% | 6.4% | |
| GDP Price Index[2] | 1.5% | 5.9% | 6.5% | 2.6% | 0.78 |
| Consumer Price Index - Urban[3] | 1.0% | 5.1% | 8.0% | 3.8% | 0.60 |

Sources:
[1] Warriner Direct, Table 16: Historical Actual Meters Purchased by Year, Page 44.
[2] Blue Chip Financial Forecasts, Page 2, multiple reports.
[3] U.S. Bureau of Labor Statistics CPI-U Midwest.

[16]Blue Chip Financial Forecasts, April 1, 2025, page 2.

As can be seen from Table CTF-8, the GDP Price Index had a higher correlation (0.78) to the actual cost per unit of natural gas meters than the Consumer Price Index – Urban (0.60). Thus, going forward the GDP Price Index is more likely to be an accurate predictor of the future costs of gas meters than the Consumer Price Index – Urban being proposed by the Company.

**Q HOW DO YOU RECOMMEND THE COMPANY UPDATE ITS O&M INFLATION FACTORS?**

A I recommend Consumers use the Blue Chip GDP Chained Price Index for the O&M inflation factors. The non-labor inflation rate used by the Company is not well supported, and the CPI non-labor inflation rate is well above the consensus industry experts' opinion of the GDP Chained Price Index. I have shown the impact of the revised inflation rate on O&M expense in Table CTF-9.

**TABLE CTF-9**

**Operating and Maintenance Expense Inflation Adjustment**
**($1,000s)**

| Decription | Historical O&M for the 12 Months Ended 12/31/2023 | Projected Adjustments: Inflation & Merit for the 12 Months Ended 12/31/2024 | Inflation & Merit for the 12 Months Ended 12/31/2025 | Inflation & Merit for the 10 Months Ended 10/31/2026 | Other Adjustments | Total Projected Adjustments | Projected O&M for the 12 Months Ended 10/31/2026 |
|---|---|---|---|---|---|---|---|
| Company Proposed | $ 341,246 | $ 1,494 | $ 1,155 | $ 1,027 | $ (28,806) | $ (25,131) | $ 316,115 |
| Revised | 341,246 | 1,468 | 1,141 | 1,019 | (29,114) | (25,486) | 315,760 |
| Adjustment | $ - | $ (26.2) | $ (13.7) | $ (7.9) | $ (307.2) | $ (355.1) | $ (355.1) |

Source: Exhibit No.: A-13 (HLR-42), Schedule: C-5.1 and Blue Chip Financial Forecast, Apirl 1, 2025 at 2.

As can be seen from Table CTF-9 above, the adjustment to the inflation factor reduced the Company's proposed O&M expense by approximately $355,100.

# IV. CONCLUSION

**Q PLEASE SUMMARIZE YOUR CONCLUSIONS AND RECOMMENDATIONS.**

A I have four recommendations for the Commission: (1) Reduce the EIRP - Distribution capital expenditures to recent historical levels; (2) Deny recovery of cost variances associated with historical asset relocation capital expenditures; (3) Deny the Company's request for additional O&M expense to address leak repairs; and (4) adjust the Company's proposed non-labor inflation rates. I have summarized the impact of my recommendations in Table CTF-10 below.

**Table CTF-10**

**Summary of Adjustments**
**($Millions)**

| Description | Capital Expense | Rev. Req. Impact At Company Proposed ROR | Rev. Req. Impact At ABATE Proposed ROR |
|---|---|---|---|
| Capital Expenditures | | | |
| EIRP - Distribution | $171.1 | $6.54 | $5.65 |
| Asset Relocation | $15.8 | $0.60 | $0.52 |
| Subtotal | $186.9 | $7.15 | $6.17 |
| O&M Expenditures | | | |
| Leak Repairs | | $1.3 | $1.3 |
| Inflation Factors | | $0.4 | $0.4 |
| Subtotal | | $1.7 | $1.7 |
| Total | | **$8.8** | **$7.8** |

As shown in Table CTF-10, the total impact of my proposed adjustments is a $8.8 million reduction in revenue requirement at the Company's proposed ROR and $7.8 million at ABATE's proposed ROR.

**Q DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?**

A Yes, it does.

# Qualifications of Colin T. Fitzhenry

**Q PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.**

A Colin Fitzhenry. My business address is 16690 Swingley Ridge Road, Suite 140, Chesterfield, MO 63017.

**Q PLEASE STATE YOUR OCCUPATION.**

A I am a consultant in the field of public utility regulation and an Associate with the firm of Brubaker & Associates, Inc. ("BAI"), energy, economic and regulatory consultants.

**Q PLEASE SUMMARIZE YOUR EDUCATIONAL BACKGROUND AND EXPERIENCE.**

A I received a Bachelor of Science in General Engineering from the University of Illinois Urbana-Champaign, which provided a broad background in mechanics and control systems. Prior to joining BAI, I served as an Engineer Intern for Dynegy Inc., where I was involved with generation operation at both Vermilion Power Station and Tilton Power Station.

Since joining BAI in January 2013, I have provided assistance in several regulated utility matters. Some of these include resource planning, transmission planning, fuel cost recovery, environmental compliance plans, mergers, asset transfers, electrical and commodity price forecasting, and power procurement.

The firm of Drazen-Brubaker & Associates, Inc. was incorporated in 1972 and assumed the utility rate and economic consulting activities of Drazen Associates, Inc., founded in 1937. In April, 1995 the firm of Brubaker & Associates, Inc. was formed. It includes most of the former DBA principals and staff. Our staff includes consultants with backgrounds in accounting, engineering, economics, finance, mathematics, computer science and business.

Brubaker & Associates, Inc. and its predecessor firm have participated in over 700 major utility rate and other cases and statewide generic investigations before utility regulatory commissions in 40 states, involving electric, gas, water, and steam rates and other issues. Cases in which the firm has been involved have included more than 80 of the 100 largest electric utilities and over 30 gas distribution companies and pipelines.

While the firm has always assisted its clients in negotiating contracts for utility services in the regulated environment, increasingly there are opportunities for certain customers to acquire power on a competitive basis from a supplier other than its traditional electric utility. The firm assists clients in identifying and evaluating purchased power options, conducts RFPs and negotiates with suppliers for the acquisition and delivery of supplies. We have prepared option studies and/or conducted RFPs for competitive acquisition of power supply for industrial and other end-use customers throughout the United States and in Canada, involving total needs in excess of 3,000 megawatts. The firm is also an associate member of the Electric Reliability Council of Texas.

In addition to our main office in St. Louis, the firm also has branch offices in Corpus Christi, Texas; Louisville, Kentucky and Phoenix, Arizona.

**Q HAVE YOU PROVIDED TESTIMONY IN UTILITY REGULATORY PROCEEDINGS?**

A Yes. I have testified before regulatory commissions in ten states, Illinois, Maryland, Wyoming, Georgia, Michigan, Oregon, Nevada, Utah, the District of Columbia, and Kansas. A summary of my testimony in utility regulatory proceedings is provided in the table below.

| Summary of Testimony in Utility Regulatory Proceedings | | | |
|---|---|---|---|
| **Application** | **Commission** | **Docket/Case No.** | **Subject** |
| Ameren Illinois Company | Illinois Commerce Commission | Docket No. 22-0487 | Capital Projects and System Reliability Metrics |
| Commonwealth Edison Company | Illinois Commerce Commission | Docket No. 22-0486 | Capital Projects and System Reliability Metrics |
| Columbia Gas of Maryland, Inc. | Maryland Public Service Commission | Case No. 9701 | Capital Expenditures and STRIDE Investments |
| Rocky Mountain Power | Public Service Commission of Wyoming | Docket No. 20000-633-ER-23 | Net Power Cost and Energy Cost Adjustment Mechanism |
| Washington Gas Light Company | Maryland Public Service Commission | Case No. 9704 | Infrastructure Riders and Capital Expenditures |
| Georgia Power Company | Georgia Public Service Commission | Docket No. 55378 | Integrated Resource Planning |
| Rocky Mountain Power | Public Service Commission of Wyoming | Docket No. 20000-653-EA-23 | Reliability and Power Quality, Service Quality Reports |
| DTE Gas Company | Michigan Public Service Commission | Case No. U-21291 | Captial and Operating Expenditures |
| Easton Utiliities Commission | Maryland Public Service Commission | Case No. 9719 | Captial and Power Production Expenditures |
| PacifiCorp | Publiic Utility Commission of Oregon | Docket No. UE 434 | Net Power Cost and Transition Adjustment Mechanism |
| Chesapeake Utilities Corporation | Maryland Public Service Commission | Case No. 9722 | Capital Expenditures and Operating and Maintenance Expenditures |
| Baltimore Gas and Electric Company | Maryland Public Service Commission | Case No. 9645 | Reconciliation of Mulit-Year Rate Plan |
| Columbia Gas of Maryland, Inc. | Maryland Public Service Commission | Case No. 9754 | Capital Expenditures and STRIDE Investments |
| Rocky Mountain Power | Public Service Commission of Wyoming | Docket No. 20000-653-EA-24 | Reliability and Power Quality, Service Quality Reports |
| NV Energy | Nevada Public Service Commission | Docket No. 24-05041 | Load Forecast |
| Rocky Mountain Power | Utah Public Service Commission | Docket No. 24-035-04 | Net Power Cost |
| Washington Gas Light Company | Public Service Commission of the District of Columbia | Case No. 1179 | Approval for Natural Gas Infrastructure Replacement Plan |
| Rocky Mountain Power | Public Service Commission of Wyoming | Docket No. 20000-671-ER-24 | Net Power Cost and Production Cost Modeling |
| Washington Gas Light Company | Public Service Commission of the District of Columbia | Case No. 1180 | Capital Expenditures and PROJECTpipes Investments |
| Evergy Kansas Central | Kansas Corporation Commission | Docket No. 25-EKCE-207-PRE | Predetermination of Ratemaking Principles for New Generating Resources |

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**STATE OF MICHIGAN**
**BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION**

| | | |
|---|---|---|
| **In the matter of the application of CONSUMERS ENERGY COMPANY for authority to increase its rates for the distribution of natural gas and for other relief.** | ) | **Case No. U-21806** |

Rebuttal Testimony of

**Colin T. Fitzhenry**

On behalf of

**Association of Businesses Advocating Tariff Equity**

May 14, 2025

BRUBAKER & ASSOCIATES, INC.

Project 11775

**STATE OF MICHIGAN**
**BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION**

| | | |
|---|---|---|
| **In the matter of the application of CONSUMERS ENERGY COMPANY for authority to increase its rates for the distribution of natural gas and for other relief.** | ) | **Case No. U-21806** |

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**STATE OF MICHIGAN**
**BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION**

| | | |
|---|---|---|
| **In the matter of the application of CONSUMERS ENERGY COMPANY for authority to increase its rates for the distribution of natural gas and for other relief.** | ) | **Case No. U-21806** |

# Rebuttal Testimony of Colin T. Fitzhenry

## I. INTRODUCTION

**Q PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.**

A Colin T. Fitzhenry. My business address is 16690 Swingley Ridge Road, Suite 140, Chesterfield, MO 63017.

**Q ARE YOU THE SAME COLIN T. FITZHENRY WHO PREVIOUSLY FILED TESTIMONY IN THIS PROCEEDING?**

A Yes. I filed Direct Testimony on behalf of the Association of Businesses Advocating Tariff Equity ("ABATE") on April 23, 2025.

**Q WHAT IS THE PURPOSE OF YOUR REBUTTAL TESTIMONY?**

A The purpose of my Rebuttal Testimony is to respond to the Direct Testimony of the Michigan Public Service Commission Staff ("Staff") Witness Cynthia Creisher. Specifically, I address Ms. Creisher's recommendation with respect to the Consumers Energy Company's ("Consumers" or the "Company") Enhanced Infrastructure Replacement Program ("EIRP"). While I do not address other areas of Ms. Creisher's

testimony, that should not be interpreted as an endorsement or disagreement with other areas of testimony not addressed.

## II. RESPONSE TO STAFF WITNESS CYNTHIA CREISHER

**Q PLEASE DESCRIBE MS. CREISHER'S REVIEW OF THE EIRP.**

A Ms. Creisher briefly describes the scope of work and the projects planned to be completed under the EIRP.[1] In addition, Ms. Creisher describes the Company's projected cost per mile of main replacement and the total cost of the EIRP program.[2]

**Q DID MS. CREISHER'S TESTIMONY INCLUDE ANY REVIEW OF THE COMPANY'S SAFETY AND RELIABILITY METRICS RELATING TO NATURAL GAS DELIVERY?**

A No.

**Q DID MS. CREISHER'S TESTIMONY INCLUDE ANY REVIEW OF THE CAUSE OF NATURAL GAS LEAKS IN THE COMPANY'S DISTRIBUTION SYSTEM?**

A No.

**Q DID MS. CREISHER'S TESTIMONY INCLUDE ANY REVIEW OF THE RISK PRESENTED FROM THE COMPANY'S PLANNED EIRP DISTRIBUTION MAIN REPLACEMENT SEGMENTS?**

A No.

[1] Creisher Direct at 6.
[2] Creisher Direct at 7.

**Q WHAT DID MS. CREISHER RECOMMEND WITH RESPECT TO THE EIRP – DISTRIBUTION PROGRAM?**

A Staff generally endorses the Company's goal of accelerating the replacement of distribution mains, aiming for completion by 2035. They also noted that Consumers Energy's projected costs indicate that the Company is making strides in reducing the per-mile cost for installing new plastic mains. Despite this support, Staff also encouraged Consumers Energy to persistently seek and implement measures to manage the program's costs effectively, thereby minimizing the financial impact on its customers.[3]

**Q DOES MS. CREISHER'S DIRECT TESTIMONY CHANGE YOUR RECOMMENDATION WITH RESPECT TO THE COMPANY'S PROPOSED EIRP INVESTMENTS?**

A No. Ms. Creisher's assessment of the EIRP – Distribution Program includes no assessment of the Company's current safety and reliability metrics and whether they support a need for accelerated main replacement. In addition, her testimony provides no consideration for the cause of leaks on the Company's distribution system. Finally, Ms. Creisher's testimony does not include an assessment of the distribution main segments the Company is proposing to replace, and whether the risk of those segments warrant accelerated replacement.

As a result, I continue to recommend that the Company can replace distribution main segments at reduced levels and still maintain the safety and reliability of the distribution system. I recommend that the Company's proposed expenditure levels in its EIRP – Distribution program be reduced to the average historical expenditure level

[3] Creisher Direct at 8.

over the past five years ($143 million). This adjustment would reduce capital expenditures by $79.4 million in 2025 and $92.1 million in 2026 for a total of $171.1 million in its forecasted test periods.[4]

**Q DOES THIS CONCLUDE YOUR REBUTTAL TESTIMONY?**

A Yes, it does.

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[4] Fitzhenry Direct at 10.

MR. CAMPBELL: Mr. Walters' direct testimony consists of a cover page, a table of contents, 73 pages of questions and answers, and an Appendix A setting out his qualifications, and along with his direct testimony, Mr. Walters sponsored Exhibits AB-6 through AB-20. And Mr. Walters did not file any rebuttal testimony.

JUDGE VARCHETTI: All right. Are there any objections to binding in the direct testimony of Mr. Walters or the associated exhibits?

I am hearing none, so his direct testimony is bound into the record, and the associated exhibits are admitted.

MR. CAMPBELL: Thank you, Your Honor.

(Direct Testimony and Appendix A bound in)

**STATE OF MICHIGAN**
**BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION**

| | | |
|---|---|---|
| **In the matter of the application of CONSUMERS ENERGY COMPANY for authority to increase its rates for the distribution of natural gas and for other relief.** | ) | **Case No. U-21806** |

Direct Testimony and Exhibits of

**Christopher C. Walters**

On behalf of

**Association of Businesses Advocating Tariff Equity**

April 23, 2025

BRUBAKER & ASSOCIATES, INC.

Project 11775

**STATE OF MICHIGAN**
**BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION**

| | | |
|---|---|---|
| **In the matter of the application of CONSUMERS ENERGY COMPANY for authority to increase its rates for the distribution of natural gas and for other relief.** | ) | **Case No. U-21806** |

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Appendix A: Qualifications of Christopher C. Walters

Exhibit AB-6: Valuation Metrics

Exhibit AB-7: Proxy Group

Exhibit AB-8: Consensus Analysts' Growth Rates

Exhibit AB-9: Constant Growth DCF Model (Consensus Analysts' Growth Rates)

Exhibit AB-10: Payout Ratios

Exhibit AB-11: Sustainable Growth Rate

Exhibit AB-12: Constant Growth DCF Model (Sustainable Growth Rate)

Exhibit AB-13: Multi-Stage Growth DCF Model

Exhibit AB-14: Common Stock Market/Book Ratio

Exhibit AB-15: Equity Risk Premium – Treasury Bond

Exhibit AB-16: Equity Risk Premium – Utility Bond

Exhibit AB-17: Bond Yield Spreads

Exhibit AB-18: 3 and 6 Month Treasury and Utility Bond Yields

Exhibit AB-19: Beta

Exhibit AB-20: CAPM Return

**STATE OF MICHIGAN**
**BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION**

| | | |
|---|---|---|
| **In the matter of the application of CONSUMERS ENERGY COMPANY for authority to increase its rates for the distribution of natural gas and for other relief.** | ) | **Case No. U-21806** |

**Direct Testimony of Christopher C. Walters**

# I. INTRODUCTION

**Q PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.**

A Christopher C. Walters. My business address is 16690 Swingley Ridge Road, Suite 140, Chesterfield, MO 63017.

**Q WHAT IS YOUR OCCUPATION?**

A I am a consultant in the field of public utility regulation and a Principal with the firm of Brubaker & Associates, Inc. ("BAI"), energy, economic and regulatory consultants.

**Q PLEASE DESCRIBE YOUR EDUCATIONAL BACKGROUND AND EXPERIENCE.**

A This information is included in Appendix A to my testimony.

**Q ON WHOSE BEHALF ARE YOU APPEARING IN THIS PROCEEDING?**

A I am appearing on behalf of the Association of Businesses Advocating Tariff Equity ("ABATE"). ABATE consists of large usage customers that purchase substantial amounts of electric power and/or delivery service from Consumers Energy Company ("Consumers Energy" or "Company").

**Q WHAT IS THE PURPOSE OF YOUR DIRECT TESTIMONY?**

A The purpose of my testimony is to address a fair overall rate of return ("ROR") including a reasonable capital structure and return on equity ("ROE").

My silence with respect to any position taken by Consumers Energy in its Application or Direct Testimonies in this proceeding should not be interpreted as an endorsement of that position.

## II. SUMMARY

**Q PLEASE SUMMARIZE YOUR CONCLUSIONS AND RECOMMENDATIONS.**

A In Section III of my testimony, I review and analyze the regulated utility industry's access to capital, credit rating trends, and outlooks, as well as the overall trend in the authorized ROE for utilities throughout the country. I conclude that the trend in authorized ROEs for utilities has declined over the last several years and has remained below 10.0% in more recent history. I also review the impact that the Federal Reserve's ("the Fed") monetary policy actions have had on the cost of capital.

In Section IV of my testimony, I address the Company's proposed capital structure, cost of debt, outline how a fair ROE should be established, provide an overview of the market's perception of the Company's investment risk, and present the analyses I relied on to estimate an appropriate ROE for Consumers Energy. Based on the results of several cost of equity estimation methods performed on publicly traded utility companies, I estimate the current fair market ROE for the Company to fall within the range of 9.00% to 9.90%. Based on my assessment of the Company's overall risk profile and the results of the analytical methods, I recommend Consumers Energy be awarded an ROE of 9.45%, which is the mid-point of my estimated range.

In Section V of my testimony, I respond to the testimony and analysis of Consumers Energy witness Ann Bulkley. Ms. Bulkley's indicated range for a reasonable ROE is 10.25% to 11.25%. She concludes that the Company's requested ROE of 10.25% is reasonable and fairly balances the interests of ratepayers and shareholders. As I demonstrate in this section of my testimony, Ms. Bulkley's indicated range is unreasonable and should be rejected.

Based on all the foregoing, I recommend the Michigan Public Service Commission ("Commission") adopt the following positions:

1. Reject Consumers Energy's proposed ROE of 10.25% and instead adopt my recommended ROE of 9.45%, which is based on my assessment of the current and expected capital market environment, the Company's overall risk profile, and the results of several analytical methods which I have analyzed, to determine a fair and reasonable ROE to be authorized for Consumers Energy.

2. The Commission's statement in Case No. U-21585 that "with increased certainty of recovery of investments for the company and additional derisking, the ROE could be impacted in the future depending on the record evidence in the case" provides a clear framework for revisiting the Company's authorized return when the risk profile diminishes. Consumers Energy's persistent overearning—particularly through repeated revenue sufficiencies based on fully projected test years—squarely fits within this narrative and should prompt a reduction in the Company's authorized ROE of 9.90%.

3. Reject Consumers Energy's proposed common equity ratio of 50.75%. I recommend the Commission authorize a permanent common equity ratio of 50.0%, consistent with its explicit directive issued in previous Consumers Energy rate cases.

4. My recommendations produce an overall ratemaking ROR of 5.84% and would reduce the Company's requested revenue requirement by $60.0 million.

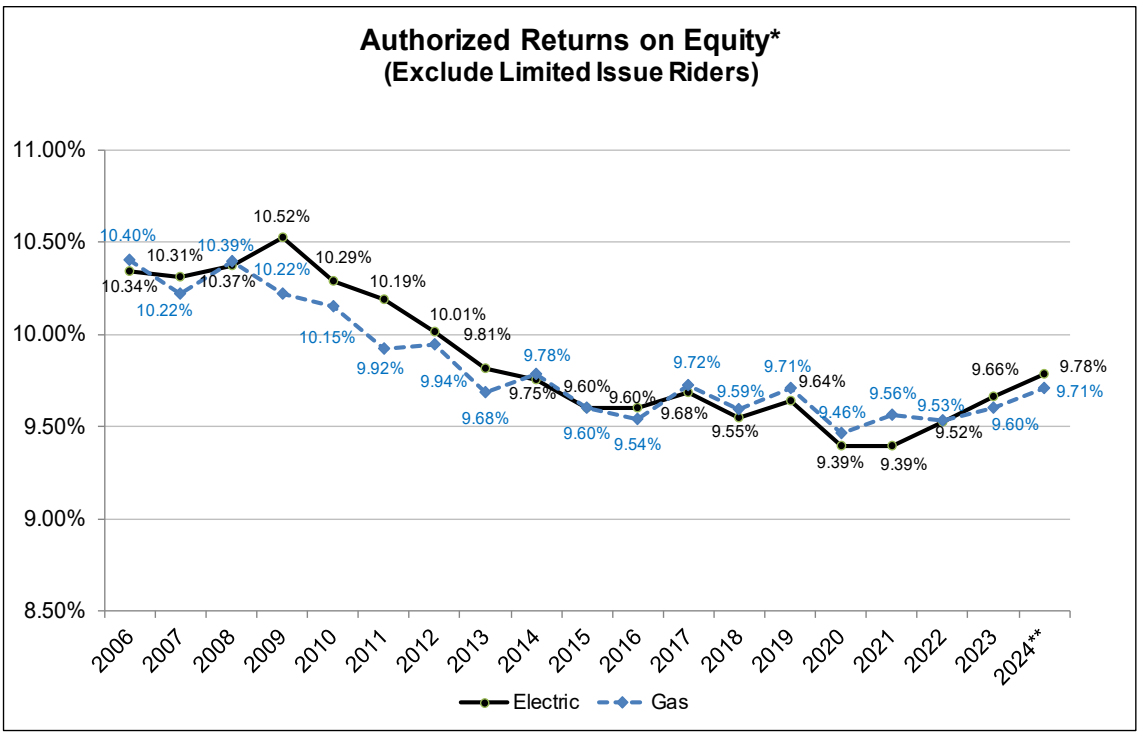
# III. INDUSTRY TRENDS AND ECONOMIC ENVIRONMENT

## A. Regulated Utility Industry Authorized ROEs, Access to Capital, and Credit Strength

**Q PLEASE DESCRIBE THE OBSERVABLE EVIDENCE ON TRENDS IN AUTHORIZED ROEs FOR ELECTRIC AND GAS UTILITIES.**

A Authorized ROEs for both electric and gas utilities have declined over the last 10 years, as illustrated in Figure CCW-1, and have been below 10.0% for about the last nine years.

**FIGURE CCW-1**




Source and Notes:
* Electric Returns exclude Limited Issue Riders.
** *S&P Global Market Intelligence*, RRA Regulatory Focus, Major Rate Case Decisions -- January - December 2024, February 3, 2025 at page 3.

**Q PLEASE DESCRIBE THE DISTRIBUTION OF AUTHORIZED ROEs FOR ELECTRIC UTILITIES FOR THE LAST FEW YEARS.**

A The distribution of authorized returns, annually, since 2016 is summarized in Table CCW-1 below.

**TABLE CCW-1**

**Distribution of Authorized ROEs**

| | | Natural Gas[1] | | | |
|---|---|---|---|---|---|
| Line | Year | Average | Median | Share of Decisions ≤ 9.5% | Share of Decisions ≤ 9.7% |
| | (1) | (2) | (3) | (4) | (5) |
| 1 | 2016 | 9.53% | 9.50% | 56.00% | 72.00% |
| 2 | 2017 | 9.73% | 9.60% | 39.13% | 69.57% |
| 3 | 2018 | 9.59% | 9.60% | 46.15% | 66.67% |
| 4 | 2019 | 9.73% | 9.73% | 19.35% | 48.39% |
| 5 | 2020 | 9.47% | 9.44% | 60.00% | 77.14% |
| 6 | 2021 | 9.56% | 9.60% | 44.19% | 67.44% |
| 7 | 2022 | 9.53% | 9.60% | 48.48% | 75.76% |
| 8 | 2023 | 9.60% | 9.55% | 45.95% | 72.97% |
| 9 | 2024 | 9.71% | 9.73% | 32.50% | 50.00% |
| 10 | 2025 | 9.71% | 9.75% | 20.00% | 40.00% |

Source and Notes:
[1] S&P Global Market Intelligence, data through March 21, 2025.
[2] S&P Global Market Intelligence, data through December 31, 2024.
- Excludes limited issue rider cases.

The distribution shows that over the last few years, the majority of authorized ROEs since 2016 have been below 9.7%, with many of those being below 9.5%.

**Q HOW HAS THE AUTHORIZED COMMON EQUITY RATIO FLUCTUATED OVER THE SAME TIME PERIOD FOR UTILITIES?**

A In general, the utility industry's common equity ratio has not really deviated too much from the range of 50.0% to 52.0%. As shown in Table CCW-2 below, I have provided the authorized common equity ratios for utilities around the country, excluding the reported common equity ratios for Arkansas, Florida, Indiana, and Michigan. For my overall market analysis, I have excluded the reported authorized common equity ratios for these states because these jurisdictions include sources of capital outside of investor-supplied capital such as accumulated deferred income taxes. As such, the reported common equity ratios in these states would result in a downward bias in the reported permanent common equity ratios authorized for ratemaking purposes within my trend analysis.

**TABLE CCW-2**

**Trends in State Authorized Common Equity Ratios**
**(Industry)**

| Line | Year | Electric[1] | | Natural Gas[1] | | Water[2] | |
|---|---|---|---|---|---|---|---|
| | | Average | Median | Average | Median | Average | Median |
| | (1) | (2) | (3) | (4) | (5) | (6) | (7) |
| 1 | 2013 | 50.12% | 51.03% | 51.16% | 50.43% | 48.34% | 48.66% |
| 2 | 2014 | 50.28% | 50.00% | 51.90% | 51.99% | 49.69% | 50.27% |
| 3 | 2015 | 49.89% | 50.47% | 49.79% | 50.33% | 51.52% | 51.68% |
| 4 | 2016 | 49.70% | 49.99% | 51.85% | 51.35% | 50.65% | 50.77% |
| 5 | 2017 | 50.02% | 49.85% | 51.13% | 51.76% | 48.43% | 46.09% |
| 6 | 2018 | 50.60% | 50.23% | 51.56% | 51.51% | 52.41% | 53.22% |
| 7 | 2019 | 51.55% | 51.37% | 52.81% | 52.42% | 50.75% | 50.35% |
| 8 | 2020 | 50.93% | 51.17% | 52.34% | 52.00% | 49.75% | 49.10% |
| 9 | 2021 | 51.01% | 52.00% | 51.90% | 52.00% | 51.96% | 52.73% |
| 10 | 2022 | 51.57% | 51.92% | 51.65% | 52.00% | 51.53% | 51.15% |
| 11 | 2023 | 51.59% | 52.27% | 52.45% | 52.00% | 52.53% | 53.40% |
| 12 | 2024 | 51.07% | 52.10% | 52.25% | 52.40% | 52.02% | 52.13% |
| 13 | 2025 | 50.21% | 50.00% | 50.46% | 50.00% | | |
| 11 | Min | 49.70% | 49.85% | 49.79% | 50.00% | 48.34% | 0.46% |
| 12 | Max | 51.59% | 52.27% | 52.81% | 52.42% | 52.53% | 0.53% |
| 14 | Average | 50.66% | 50.95% | 51.64% | 51.55% | 50.80% | 0.51% |
| 15 | Median | 50.60% | 51.03% | 51.85% | 51.99% | 51.13% | 0.51% |

Source and Notes:
[1] S&P Global Market Intelligence; data through March 21, 2025.
[2] S&P Global Market Intelligence; data through December 31, 2024.
- Excludes Arkansas, Florida, Indiana and Michigan because they include non-investor capital.

**Q HAVE REGULATED UTILITY COMPANIES BEEN ABLE TO MAINTAIN RELATIVELY STRONG CREDIT RATINGS DURING PERIODS OF DECLINING AUTHORIZED ROEs?**

A Yes. As shown below in Table CCW-3, the credit ratings of the industry have improved since 2009. In 2009, approximately 75% of the industry was rated BBB+ or higher. Currently, 87% of the industry has a rating of BBB+ or higher.

**TABLE CCW-3**

**S&P Ratings by Category**
**Natural Gas and Water Utility Subsidiaries**
**(Year End)**

| Description | 2009 | 2010 | 2011 | 2012 | 2013 | 2014 | 2015 | 2016 | 2017 | 2018 | 2019 | 2020 | 2021 | 2022 | 2023 | 2024 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **A or higher** | 50% | 50% | 50% | 50% | 38% | 33% | 33% | 44% | 56% | 33% | 38% | 38% | 13% | 15% | 17% | 14% |
| **A-** | 0% | 0% | 0% | 0% | 38% | 33% | 33% | 22% | 11% | 11% | 38% | 38% | 38% | 38% | 38% | 35% |
| **BBB+** | 25% | 25% | 38% | 38% | 13% | 22% | 33% | 33% | 33% | 44% | 13% | 13% | 25% | 30% | 29% | 38% |
| **BBB** | 13% | 13% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 11% | 13% | 13% | 25% | 18% | 16% | 12% |
| **BBB-** | 13% | 13% | 13% | 13% | 13% | 11% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% |
| **Below BBB-** | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 1% |
| **Total** | **100%** | **100%** | **100%** | **100%** | **100%** | **100%** | **100%** | **100%** | **100%** | **100%** | **100%** | **100%** | **100%** | **100%** | **100%** | **100%** |

Source: S&P CAPITAL IQ and Market Intelligence, data retrieved 12/31/2024.
Note: Subsidiary ratings used.

**Q HAVE UTILITIES BEEN ABLE TO ACCESS EXTERNAL CAPITAL TO SUPPORT CAPITAL EXPENDITURE PROGRAMS?**

A Yes. Regulatory Research Associates' ("RRA") October 22, 2024 Utility Capital Expenditures report, *RRA Financial Focus*, a division of *S&P Global Market Intelligence*, made several relevant comments about utility investments generally:[1]

- Energy utility capex estimates for 2025, 2026 and 2027 indicate successively higher spending levels, reaching $192 billion, $196.5 billion and $197 billion, respectively. Spending in these years is likely to increase further, as the companies' plans for future projects continue to solidify around federal and state legislation supporting infrastructure investment.

- Multiple drivers are expected to elevate utility capital expenditures over the next several years. Pent-up demand to replace aging equipment is already pushing utilities to make considerable investments in infrastructure. Meanwhile, the renewable energy portfolio standards for multiple states continue to ramp up, with the plans specifying large expansions of low-carbon energy generation capacity. Amplifying these factors are federal infrastructure investment plans, including the Inflation Reduction Act of 2022, which aim to convert the US power generation network to a majority of zero-carbon sources by 2035.

- Forecast aggregate utility investments in 2025, 2026 and 2027 are expected to reach new records of $192 billion, $196.5 billion and $197 billion, respectively. The increases are being driven in large part by federal legislation enacted in 2021 and 2022, supporting

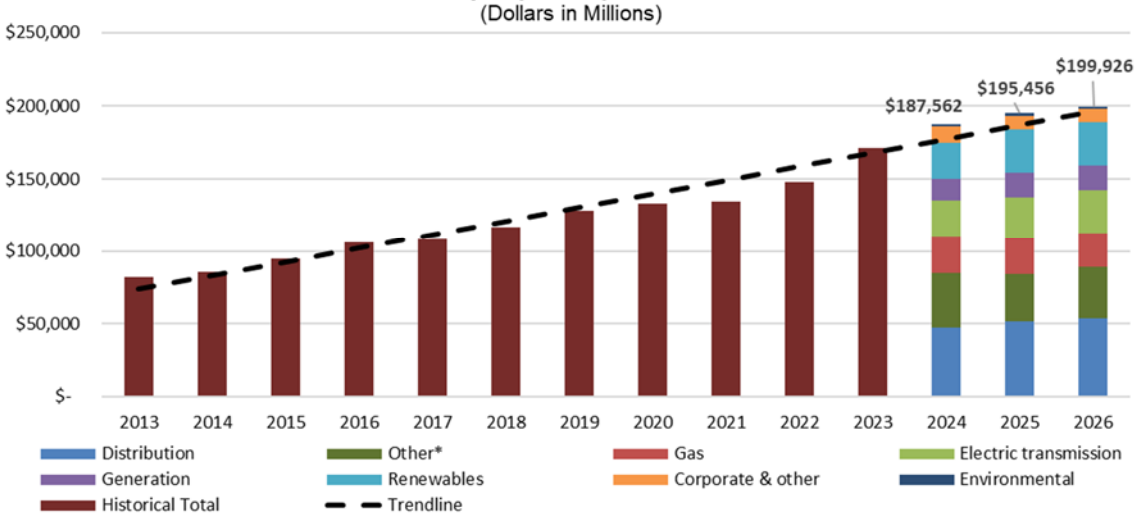
[1] *S&P Global Market Intelligence, RRA Financial Focus*: "Utility capital expenditures update," October 22, 2024.

infrastructure investment and state-level energy transition plans and incentives, as well as robust growth in demand from datacenters, as the explosion in implementation of AI and cloud computing continues.

- Utilities have multiple opportunities to finance and support energy investments through mechanisms available within the Inflation Reduction Act and the Infrastructure Investment and Jobs Act of 2021. These pieces of legislation provide billions of dollars for power infrastructure investments, financial incentives for nuclear power plants and funding for battery storage technology, among other provisions.

As shown in Figure CCW-2 below, capital expenditures for the regulated electric and natural gas delivery utilities have increased considerably over the period 2023 into 2024, and the forecasted capital expenditures remain elevated through the end of 2026.

**FIGURE CCW-2**




*Other category consists of utilities that do not report capital expenditures by category: Avista, Dominion Energy, NorthWestern, and PG&E.
Source: *S&P Global Market Intelligence, RRA Financial Focus*, Utility Capital Expenditures Update, October 22, 2024, Tables 1 and 3.

As demonstrated in Figure CCW-2 above, and in the comments made by *RRA S&P Global Market Intelligence*, capital investments for the utility industry continue to stay at elevated levels, and these capital expenditures are expected to fuel utilities' profit growth into the foreseeable future. This is clear evidence that the capital

investments are enhancing shareholder value and are attracting both equity and debt capital to the utility industry in a manner that allows for funding these elevated capital investments. While capital markets embrace these profit-driven capital investments, regulatory commissions also must be careful to maintain reasonable prices and tariff terms and conditions to protect customers' need for reliable utility service at reasonable rates. If this is not done, utility rates will expand beyond the ability of customers to pay, resulting in revenue constraints for utilities, which will impact their financial integrity.

**Q IS THERE EVIDENCE OF ROBUST VALUATIONS OF REGULATED UTILITY EQUITY SECURITIES?**

A Yes. Strong valuations demonstrate that utilities can issue securities at favorable prices and price multiples, signaling their ability to access equity capital on reasonable terms and at a relatively low cost. As shown on Exhibit AB-6, the historical valuation of utilities followed by *The Value Line Investment Survey* ("*Value Line*"), based on a Price-to-Earnings ("P/E") ratio, Price-to-Cash Flow ("P/CF") ratio, and Market Price-to-Book value ("M/B") ratio, indicates utility security valuations today are very strong and robust relative to the last several years. These strong valuations of utility stocks indicate that utilities have access to equity capital under reasonable terms and at lower costs.

**Q WHAT CONCLUSION DO YOU DRAW FROM THIS OBSERVABLE MARKET DATA IN FORMING YOUR RECOMMENDED ROE AND OVERALL ROR?**

A Generally, authorized ROEs, credit standing, and access to capital have been quite robust for utilities over the last several years, even throughout the duration of the

global pandemic. It is critical that this Commission ensure that utility rates are increased no more than necessary to provide fair compensation and maintain financial integrity.

## B. Impact of Monetary Policy

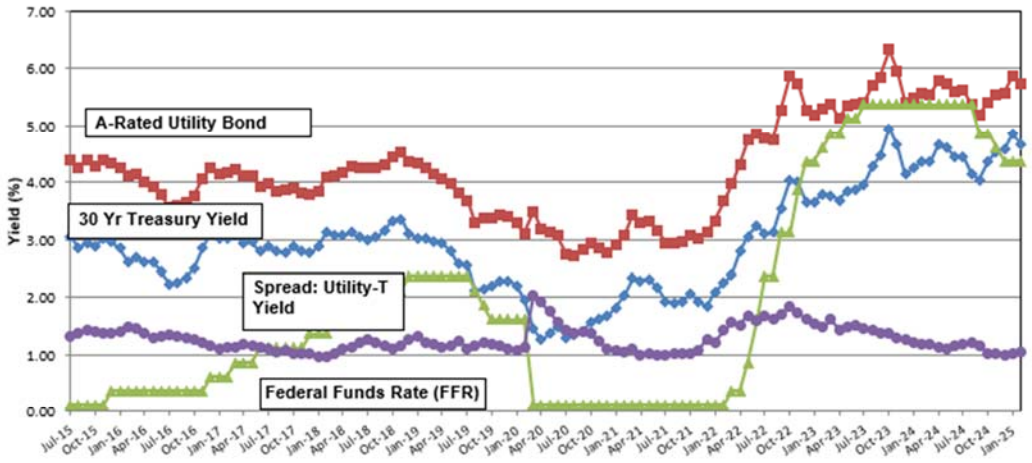
**Q ARE THE FEDERAL OPEN MARKET COMMITTEE'S ("FOMC") ACTIONS KNOWN TO THE MARKET PARTICIPANTS, AND IS IT REASONABLE TO BELIEVE THEY ARE REFLECTED IN THE MARKET'S VALUATION OF BOTH DEBT AND EQUITY SECURITIES?**

A Yes, to both questions. The Fed has been transparent about its efforts to support the economy to achieve maximum employment, and to manage long-term inflation to around a 2% level. The Fed has implemented procedures to support the economy's efforts to achieve these policy objectives. Specifically, the Fed had previously lowered the Federal Overnight Rate for securities and had engaged in a Quantitative Easing program where the Fed was buying, monthly, Treasury and mortgage-backed securities in order to moderate the demand in the marketplaces and support the economy. Currently, the Fed is reducing its holdings of Treasury securities and agency debt and agency mortgage-backed securities. Such monetary policy actions include raising the target federal funds rate and allowing maturing bonds to roll off its balance sheet.

A visualization of the market's reaction to the Fed's actions on the federal funds rate is shown below in Figure CCW-3.

**FIGURE CCW-3**

**Timeline of Federal Funds Rate Changes Since 2015**




**Fed FFR Actions:**

| | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|
| 1 | December 2015 | 0.25 | → | 0.50 | 15 | March 2022 | 0.25 | → | 0.50 |
| 2 | December 2016 | 0.50 | → | 0.75 | 16 | May 2022 | 0.75 | → | 1.00 |
| 3 | March 2017 | 0.75 | → | 1.00 | 17 | June 2022 | 1.50 | → | 1.75 |
| 4 | June 2017 | 1.00 | → | 1.25 | 18 | July 2022 | 2.25 | → | 2.50 |
| 5 | December 2017 | 1.25 | → | 1.50 | 19 | September 2022 | 3.00 | → | 3.25 |
| 6 | March 2018 | 1.50 | → | 1.75 | 20 | November 2022 | 3.75 | → | 4.00 |
| 7 | June 2018 | 1.75 | → | 2.00 | 21 | December 2022 | 4.25 | → | 4.50 |
| 8 | September 2018 | 2.00 | → | 2.25 | 22 | February 2023 | 4.50 | → | 4.75 |
| 9 | December 2018 | 2.25 | → | 2.50 | 23 | March 2023 | 4.75 | → | 5.00 |
| 10 | August 2019 | 2.00 | → | 2.25 | 24 | May 2023 | 5.00 | → | 5.25 |
| 11 | September 2019 | 1.75 | → | 2.00 | 25 | July 2023 | 5.25 | → | 5.50 |
| 12 | October 2019 | 1.50 | → | 1.75 | 26 | September 2024 | 4.75 | → | 5.00 |
| 13 | March 2020 | 1.00 | → | 1.25 | 27 | November 2024 | 4.50 | → | 4.75 |
| 14 | March 2020 | 0.00 | → | 0.25 | 28 | December 2024 | 4.25 | → | 4.50 |

Sources:
Federal Reserve Bank of New York, https://apps.newyorkfed.org/markets/autorates/fed-funds-search-page
Board of Governors of the Federal Reserve System, https://www.federalreserve.gov/datadownload/
Mergent Bond Record.

As shown in Figure CCW-3 above, the rise in the federal funds rate has far outpaced the rise in Utility and Treasury yields while the spread of Utility bonds over Treasury bond yields have stabilized recently.

**Q HAS THE FED MADE RECENT COMMENTS CONCERNING MONETARY POLICY AND THE POTENTIAL IMPACT ON INTEREST RATES?**

A Yes. On March 19, 2025, the FOMC released the following statement:

> Recent indicators suggest that economic activity has continued to expand at a solid pace. The unemployment rate has stabilized at a

> low level in recent months, and labor market conditions remain solid. Inflation remains somewhat elevated.
>
> The Committee seeks to achieve maximum employment and inflation at the rate of 2 percent over the longer run. Uncertainty around the economic outlook has increased. The Committee is attentive to the risks to both sides of its dual mandate.
>
> In support of its goals, the Committee decided to maintain the target range for the federal funds rate at 4-1/4 to 4-1/2 percent. In considering the extent and timing of additional adjustments to the target range for the federal funds rate, the Committee will carefully assess incoming data, the evolving outlook, and the balance of risks. The Committee will continue reducing its holdings of Treasury securities and agency debt and agency mortgage-backed securities. Beginning in April, the Committee will slow the pace of decline of its securities holdings by reducing the monthly redemption cap on Treasury securities from $25 billion to $5 billion. The Committee will maintain the monthly redemption cap on agency debt and agency mortgage-backed securities at $35 billion. The Committee is strongly committed to supporting maximum employment and returning inflation to its 2 percent objective.
>
> In assessing the appropriate stance of monetary policy, the Committee will continue to monitor the implications of incoming information for the economic outlook. The Committee would be prepared to adjust the stance of monetary policy as appropriate if risks emerge that could impede the attainment of the Committee's goals. The Committee's assessments will take into account a wide range of information, including readings on labor market conditions, inflation pressures and inflation expectations, and financial and international developments.[2]

The above quote suggests economic activity is expanding solidly, with solid labor market conditions though inflation remains somewhat elevated. To support its goals of maximum employment and 2% inflation, the Fed is maintaining the federal funds rate target range at 4.25% to 4.5%. It will continue reducing its securities holdings but will slow the pace of Treasury redemptions from $25 billion to $5 billion per month starting in April, while keeping agency debt and MBS redemptions at $35 billion per month.

[2] Federal Reserve Board - Federal Reserve issues FOMC statement, March 19, 2025.

**Q WHAT DO INDEPENDENT ECONOMISTS' OUTLOOKS FOR FUTURE INTEREST RATES INDICATE?**

A Independent economists, surveyed by *Blue Chip Financial Forecasts,* expect current capital costs to remain relatively flat to marginally increase over the near term, while maintaining levels that are still relatively low by historical standards. For example, independent projections show that the consensus is the federal funds rate will decrease while long-term interest rates, as measured by the 30-year Treasury bond, are expected to remain relatively flat. Inflation, as measured through the Gross Domestic Product ("GDP") price index, is expected to be a mix of marginal increases and decreases over the near to intermediate term. The consensus projections for the next several quarters are provided in Table CCW-4 below.

**TABLE CCW-4**

**Blue Chip Financial Forecasts**
**Projected Federal Funds Rate, 30-Year Treasury Bond Yields, and GDP Price Index**

| Publication Date | 4Q 2023 | 1Q 2024 | 2Q 2024 | 3Q 2024 | 4Q 2024 | 1Q 2025 | 2Q 2025 | 3Q 2025 | 4Q 2025 | 1Q 2026 | 2Q 2026 |
|---|---|---|---|---|---|---|---|---|---|---|---|
| Federal Funds Rate | | | | | | | | | | | |
| Mar-24 | **5.3** | 5.4 | 5.2 | 4.9 | 4.5 | 4.2 | 3.8 | | | | |
| Apr-24 | | 5.3 | 5.2 | 5.0 | 4.6 | 4.2 | 3.9 | 3.7 | | | |
| May-24 | | 5.3 | 5.4 | 5.2 | 4.9 | 4.6 | 4.3 | 4.0 | | | |
| Jun-24 | | **5.3** | 5.4 | 5.2 | 5.0 | 4.7 | 4.4 | 4.1 | | | |
| Jul-24 | | | 5.3 | 5.3 | 5.0 | 4.7 | 4.4 | 4.1 | 3.9 | | |
| Aug-24 | | | 5.3 | 5.3 | 5.0 | 4.7 | 4.4 | 4.1 | 3.9 | | |
| Sep-24 | | | **5.3** | 5.2 | 4.8 | 4.4 | 4.0 | 3.8 | 3.6 | | |
| Oct-24 | | | | 5.3 | 4.6 | 4.1 | 3.8 | 3.5 | 3.3 | 3.3 | |
| Nov-24 | | | | 5.3 | 4.6 | 4.1 | 3.8 | 3.5 | 3.3 | 3.2 | |
| Dec-24 | | | | **5.3** | 4.6 | 4.2 | 3.9 | 3.7 | 3.6 | 3.5 | |
| Jan-25 | | | | | 4.7 | 4.3 | 4.1 | 3.9 | 3.8 | 3.7 | 3.5 |
| Feb-25 | | | | | 4.7 | 4.3 | 4.2 | 4.0 | 3.9 | 3.8 | 3.6 |
| Mar-25 | | | | | **4.7** | 4.4 | 4.3 | 4.1 | 4.0 | 3.9 | 3.8 |
| T-Bond, 30 yr. | | | | | | | | | | | |
| Mar-24 | **4.6** | 4.4 | 4.3 | 4.2 | 4.2 | 4.1 | 4.1 | | | | |
| Apr-24 | | 4.3 | 4.3 | 4.2 | 4.2 | 4.1 | 4.1 | 4.0 | | | |
| May-24 | | 4.3 | 4.6 | 4.5 | 4.4 | 4.3 | 4.2 | 4.2 | | | |
| Jun-24 | | **4.3** | 4.6 | 4.5 | 4.5 | 4.4 | 4.3 | 4.3 | | | |
| Jul-24 | | | 4.6 | 4.5 | 4.4 | 4.4 | 4.3 | 4.3 | 4.2 | | |
| Aug-24 | | | 4.6 | 4.5 | 4.4 | 4.4 | 4.3 | 4.3 | 4.3 | | |
| Sep-24 | | | **4.6** | 4.2 | 4.2 | 4.1 | 4.1 | 4.1 | 4.1 | | |
| Oct-24 | | | | 4.2 | 4.1 | 4.0 | 4.0 | 4.0 | 4.1 | 4.0 | |
| Nov-24 | | | | 4.2 | 4.3 | 4.2 | 4.2 | 4.2 | 4.2 | 4.2 | |
| Dec-24 | | | | **4.2** | 4.5 | 4.5 | 4.4 | 4.4 | 4.4 | 4.4 | |
| Jan-25 | | | | | 4.5 | 4.6 | 4.5 | 4.5 | 4.5 | 4.5 | 4.4 |
| Feb-25 | | | | | 4.5 | 4.7 | 4.7 | 4.7 | 4.7 | 4.6 | 4.6 |
| Mar-25 | | | | | **4.5** | 4.7 | 4.7 | 4.7 | 4.6 | 4.6 | 4.6 |
| GDP Price Index | | | | | | | | | | | |
| Mar-24 | **1.6** | 2.2 | 2.3 | 2.2 | 2.2 | 2.1 | 2.1 | | | | |
| Apr-24 | | 2.2 | 2.4 | 2.3 | 2.2 | 2.2 | 2.1 | 2.2 | | | |
| May-24 | | 3.1 | 2.7 | 2.4 | 2.3 | 2.3 | 2.2 | 2.2 | | | |
| Jun-24 | | **3.0** | 2.8 | 2.5 | 2.3 | 2.3 | 2.3 | 2.2 | | | |
| Jul-24 | | | 2.8 | 2.3 | 2.3 | 2.4 | 2.2 | 2.2 | 2.1 | | |
| Aug-24 | | | 2.3 | 2.3 | 2.3 | 2.3 | 2.2 | 2.2 | 2.1 | | |
| Sep-24 | | | **2.5** | 2.2 | 2.2 | 2.3 | 2.2 | 2.2 | 2.1 | | |
| Oct-24 | | | | 2.2 | 2.0 | 2.2 | 2.2 | 2.1 | 2.1 | 2.1 | |
| Nov-24 | | | | 1.8 | 2.1 | 2.2 | 2.1 | 2.1 | 2.1 | 2.2 | |
| Dec-24 | | | | **1.8** | 2.2 | 2.3 | 2.2 | 2.2 | 2.3 | 2.3 | |
| Jan-25 | | | | | 2.2 | 2.3 | 2.4 | 2.4 | 2.5 | 2.6 | 2.1 |
| Feb-25 | | | | | 2.2 | 2.5 | 2.5 | 2.5 | 2.5 | 2.5 | 2.1 |
| Mar-25 | | | | | **2.4** | 2.7 | 2.5 | 2.5 | 2.5 | 2.5 | 2.2 |

Source and Note:
*Blue Chip Financial Forecasts,* February 2023 through March 2025.
Actual Yields in Bold.

Further, the outlook for long-term interest rates in the intermediate to long term is also impacted by the current Fed actions and the expectation that eventually

the Fed's monetary actions will return to more normal levels. Long-term interest rate projections are illustrated in Table CCW-5 below.

**TABLE CCW-5**

**30-Year Treasury Bond Yield Actual Vs. Projection**

| Description | Actual | Near-Term Projected* | 5- to 10-Year Projected |
|---|---|---|---|
| **2020** | | | |
| Q1 | 1.88% | 2.57% | |
| Q2 | 1.38% | 1.90% | 3.0% - 3.8% |
| Q3 | 1.36% | 1.87% | |
| Q4 | 1.62% | 1.97% | 2.8% - 3.6% |
| **2021** | | | |
| Q1 | 2.07% | 2.23% | |
| Q2 | 2.26% | 2.77% | 3.5% - 3.9% |
| Q3 | 1.93% | 2.63% | |
| Q4 | 1.95% | 2.70% | 3.4% - 3.8% |
| **2022** | | | |
| Q1 | 2.25% | 2.87% | |
| Q2 | 3.04% | 3.47% | 3.8% - 3.9% |
| Q3 | 3.26% | 3.63% | |
| Q4 | 3.90% | 3.87% | 3.9% - 4.0% |
| **2023** | | | |
| Q1 | 3.74% | 3.77% | |
| Q2 | 3.80% | 3.70% | 3.8% - 3.9% |
| Q3 | 4.24% | 3.83% | |
| Q4 | 4.58% | 4.17% | 4.1% - 4.2% |
| **2024** | | | |
| Q1 | 4.33% | 4.03% | |
| Q2 | 4.57% | 4.17% | 4.3% - 4.4% |
| Q3 | 4.22% | 4.20% | |
| Q4 | 4.50% | 4.20% | 4.3% - 4.2% |

Source and Note:
*Blue Chip Financial Forecasts,* January 2019 through March 2025.
*Average of all 3 reports in Quarter.

As outlined in Table CCW-5 above, the outlook for interest rates has moderated more recently relative to 2020 and part of 2021. For example, when actual interest rates were in the range of 1.4% to 2.1%, the near-term projections for 30-year Treasury yields ranged from 1.9% to 2.8% in 2020-2021, while the projections five to ten years out were in the range of 2.8% to 3.9%. Most recently, actual interest rates were approximately 4.5%, with near and intermediate projections in the range of 4.2% to 4.3%.

## C. Market Sentiments and Utility Industry Outlook

**Q PLEASE DESCRIBE THE CREDIT RATING OUTLOOK FOR REGULATED UTILITIES.**

A All credit rating agencies see rate affordability as an important consideration in assessing utility credit, including Standard & Poor's ("S&P") and Moody's Investors Service ("Moody's") as discussed below.

In its 2025 Outlook,[3] S&P reports that North American regulated utilities face continued credit pressure due to elevated capital spending, persistent cash flow deficits (exceeding $100 billion), and increasing physical risks such as wildfires and extreme weather. In 2024, downgrades again outpaced upgrades, a five-year trend driven by high capex, rising wildfire risk, and uneven regulatory outcomes. Despite ongoing investment in the energy transition and data center growth (which may modestly lift electricity sales by ~1% annually), financial metrics are deteriorating due to underwhelming common equity issuance and high leverage. Hybrid security issuance hit a record $26 billion in 2024 and is expected to continue helping credit support. Regulatory frameworks remain broadly credit supportive, though S&P

[3] *S&P Global Credit Ratings*, "Industry Credit Outlook 2025 – North America Regulated Utilities," January 14, 2025.

downgraded its view of Connecticut due to inconsistent returns and rising lag. Customer bill affordability remains a key consideration, especially as capacity prices rise and new infrastructure costs must be equitably allocated. Wildfire risk—particularly litigation and insurance constraints—is becoming a systemic credit concern, now affecting nearly all regions. S&P made several specific observations about affordability in the context of regulated utilities' credit quality:

1. Electric bills as a share of household income: S&P noted that the average electric customer bill is about 2% of U.S. median household income, which it characterizes as "good value" relative to other typical household expenses. Preserving this affordability is critical to maintaining the industry's credit quality, as it underpins public and regulatory support.

2. Risk from cost shifts due to data centers: S&P cautioned that if utilities assign a significant portion of new infrastructure costs related to data center growth to existing residential customers, it could lead to higher customer bills. This would, in turn, pressure regulators to limit future rate case increases, potentially impairing utilities' ability to recover costs or earn authorized returns.

3. Capacity price increases: S&P warned that higher PJM capacity prices—which are directly passed on to customers—could result in greater customer dissatisfaction. This could prompt regulators to limit increases in other parts of the customer bill, indirectly constraining utilities' ability to maintain financial performance and manage regulatory risk.

In sum, S&P views affordability as a cornerstone issue for the sector: sustained rate increases or cost shifts can threaten rate affordability. As such, it is imperative the Commission consider affordability in addition to ensuring safety and reliability.

In a recent industry report, Moody's explained that the regulated electric and gas utilities' outlook remains "Negative" largely due to increased pricing pressures on customers. Moody's stated that it changed its outlook from "Positive" to "Negative" due to the following:

> We have revised our outlook on the US regulated utilities sector to negative from stable. We changed the outlook because of increasingly challenging business and financial conditions stemming from higher natural gas prices, inflation and rising interest rates. These

> developments raise residential customer affordability issues, increasing the level of uncertainty with regard to the timely recovery of costs for fuel and purchased power, as well as for rate cases more broadly.[4]

Also, in a report published in January of 2024, S&P specifically mentioned commodity price volatility, in combination with significant increases in capital investments, driving utility rate increases which may strain affordability concerns.[5]

Finally, Fitch opined that the regulated electric and gas utilities' outlook is deteriorating due to elevated capex that put pressure on credit metrics. Fitch also notes the bill affordability concerns for ratepayers, and regulators' ability to balance the rate requests with increasing customer bills.

Specifically, Fitch states:

> Fitch Ratings' deteriorating outlook for the North American Utilities, Power & Gas sector reflects continuing macroeconomic headwinds and elevated capex that are putting pressure on credit metrics in the high-cost funding environment. Bill affordability concerns for ratepayers continue to persist despite the pull back in natural gas prices and inflationary pressures. Fitch expects utility capex to grow by double digits in 2024, underpinned by investments needed to make the electric infrastructure more resilient against extreme weather events and to accommodate renewable generation, including distributed sources. Rate case outcomes are key to watch as regulators balance more rate requests with increases in customer bills. Authorized ROEs could prove to be sticky despite an increase in cost of capital. Higher weather-normalized retail electricity sales, driven by datacenter growth and onshoring of manufacturing activities, and tax transferability provisions of the Inflation Reduction Act could somewhat offset headwinds to utilities. Ongoing management actions to sell assets and issue equity, in some cases, is supportive of parent companies' ratings. Within Fitch's coverage, 90% of ratings hold Stable Rating Outlooks. We expect limited rating movement in 2024. The number of upgrades in 2023 so far exceeds the number of

[4] *Moody's Investors Service Outlook*: "Regulated Electric and Gas Utilities – US 2023 outlook negative due to higher natural gas prices, inflation and rising interest rates," November 10, 2022 at 1. (Emphasis Added).

[5] *S&P Global Ratings*: "Industry Credit Outlook 2024: North America Regulated Utilities," January 9, 2024, at 8.

> downgrades, and is driven by positive rating actions on several parent holding companies and their regulated subsidiaries.[6]

As outlined by Moody's, S&P, and Fitch above, credit analysts are focusing on rate affordability as an important factor needed to support strong credit standing. Customers must be able to afford to pay their utility bills in order for utilities to maintain their financial integrity and strong investment grade credit standing. For this reason, this Commission should carefully assess the reasonableness of cost of service in this proceeding, including an appropriate overall ROR necessitated by a reasonably cost-effective balanced ratemaking capital structure, and a ROE that represents fair compensation but also maintains competitive, just, and reasonable rates.

## D. Additional Remarks

**Q IN LIGHT OF HIGHER LEVELS OF INFLATION, EXPECTATIONS OF HIGHER INTEREST RATES, AND GEOPOLITICAL EVENTS AROUND THE WORLD, HOW HAS THE MARKET PERCEIVED UTILITIES AS INVESTMENT OPTIONS?**

A Since the beginning of the second half of 2021, the natural gas utility sector has significantly outperformed the S&P 500, with a total return of 70.24% compared to the market's total return of 39.56%. This is presented below in Figure CCW-4. It is important to note that the S&P 500's strong performance in 2023 and early 2024 was largely driven by a small group of "mega-cap" companies known as the Magnificent 7. The Magnificent 7's stocks were among the most valuable companies in the S&P 500 index and rallied significantly over this time. Those seven stocks accounted for a majority of the S&P 500's returns even though there were 493 other companies in the

[6] *FitchRatings.* "North American Utilities, Power & Gas Outlook 2024," December 6, 2023 at 1. (Emphasis Added).

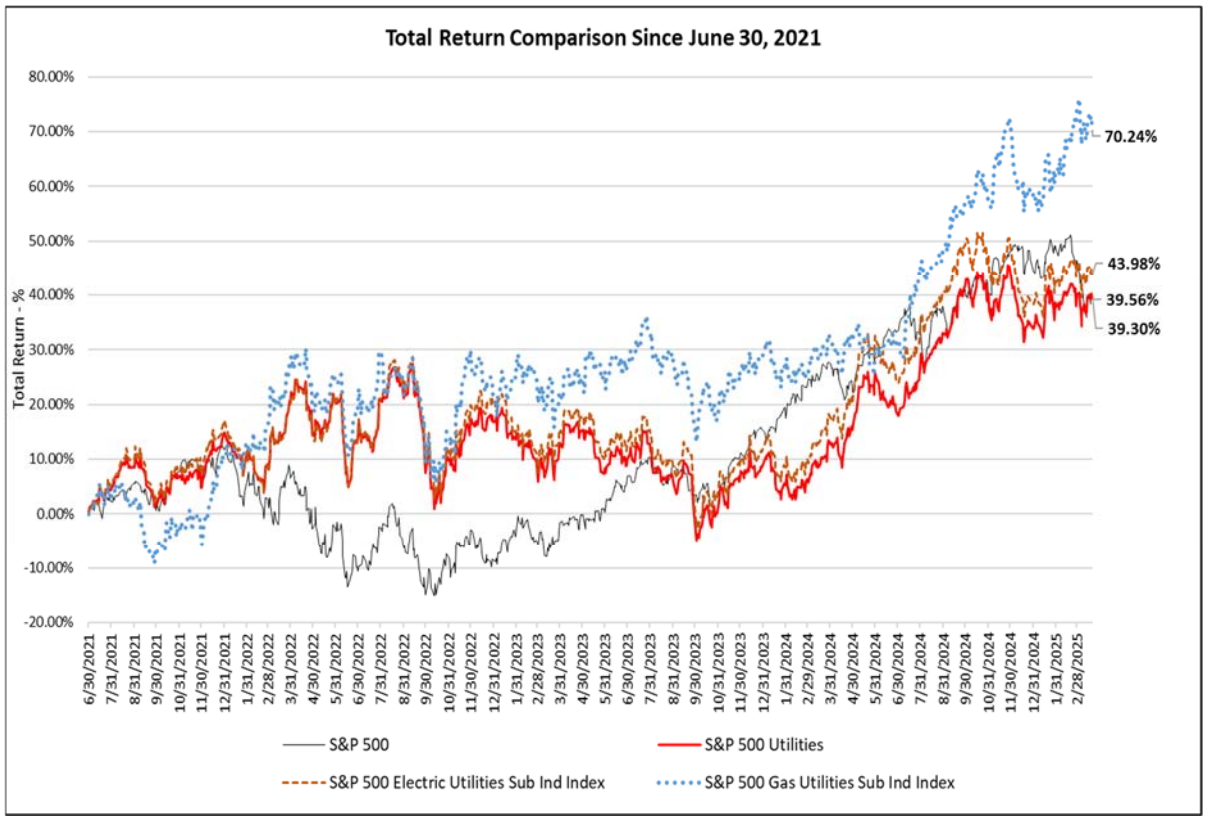
index. This is because the S&P 500 is a market capitalization-weighted index, meaning companies with larger market capitalizations have a greater impact on the index's overall performance. This is explained in the S&P Dow Jones Indices report "U.S. Equity Market Attributes April 2024," which noted that:

> Year-to-date, the S&P 500 remained up 5.57% (with 10 of the 11 sectors up; Real Estate was down 9.86%), as breadth declined but remained positive (302 up and 199 down, compared to last March's 369 and 134 YTD, respectively). The Magnificent 7 as a group still dominated, accounting for 51% of the index return (which included Apple's 11.5% YTD decline and Tesla's 26.2% YTD decline), as NVIDIA (up 74.5% YTD) represented 41% of the S&P 500's YTD gain.[7]

Generally, the utility sector has been able to deliver positive and relatively stable returns during a period of elevated inflation, rising interest rates, and uncertainty because of geopolitical events around the world.

[7] https://www.spglobal.com/spdji/en/documents/commentary/market-attributes-us-equities-202404.pdf. (Emphasis Added).

**Figure CCW-4**




# IV. RATE OF RETURN

**Q PLEASE GENERALLY DESCRIBE WHAT IS MEANT BY THE OVERALL ROR AS IT RELATES TO RATEMAKING FOR REGULATED UTILITIES.**

A The overall ROR in utility ratemaking represents the weighted average cost of capital a utility is allowed to earn on its rate base. It combines the cost of debt and the authorized ROE, weighted by the utility's capital structure.

## A. Capital Structure

**Q WHAT IS CONSUMERS ENERGY'S PROPOSED CAPITAL STRUCTURE?**

A Consumers Energy's proposed capital structure is summarized in Table CCW-6 below:

**Table CCW-6**

**Investor-Supplied Capital Structure**

| Description | Weight |
|---|---|
| Long-term Debt | 49.10% |
| Preferred Stock | 0.14% |
| Common Equity | 50.75% |
| Total | 100.00% |

Source: A-14 (MRB-1)
*Total may not add due to rounding

**Q DO YOU HAVE ANY COMMENTS ON CONSUMERS ENERGY'S PROPOSED CAPITAL STRUCTURE?**

A Yes. As I will discuss, Consumers Energy's proposed equity ratio of 50.75% is relatively higher than the equity ratio for the proxy group used to estimate the cost of equity for Consumers Energy. As shown on Exhibit AB-7, the proxy group has an average common equity ratio of 46.3% (including short-term debt) and 50.4% (excluding short-term debt). Either an adjustment to the capital structure or a reduction in the authorized ROE could be warranted given Consumers Energy's stronger financial position relative to the proxy group used to assess the Company's cost of equity.

**Q ARE YOU AWARE OF OTHER REGULATORY COMMISSIONS RECOGNIZING THE NEED TO ALIGN THE COST OF EQUITY WITH THE CAPITAL STRUCTURE?**

A Yes. In a recent Order, the Arkansas Public Service Commission adjusted the capital structure of Southwestern Electric Power Company ("SWEPCO") to be more in-line

with the comparable companies used to estimate the cost of equity.[8] The adjustment was to recognize that there must be *congruence* between the cost of equity and the capital structure. Specifically, the Order states as follows:

> Consistent with our ruling in Order No. 10 of Docket No. 06-101-U, the Commission holds that there should be congruence between the estimated cost of equity and the debt-to-equity ratio, whereby a lower DTE ratio decreases financial risk and decreases the cost of equity. The evidence of record supports imputing the average capital structure of companies with comparable risk to SWEPCO for the purposes of determining SWEPCO's overall cost of capital.[9]

As I described above, the Company's proxy group here has an average common equity ratio of 46.3% (including short-term debt) and 50.4% (excluding short-term debt) as calculated by *S&P Global Market Intelligence* and *Value Line*, respectively. The Company's proposed equity ratio of 50.75% exceeds that of the proxy group's comparable average equity ratio of 50.4%.

**Q ARE YOU RECOMMENDING AN ADJUSTMENT TO THE COMPANY'S PROPOSED CAPITAL STRUCTURE?**

A Yes. I recommend the Commission reject the Company's requested increase in its common equity ratio to 50.75%, and instead maintain its currently authorized equity ratio of 50.0% which is consistent with this Commission's explicitly stated preference as well as what is currently authorized for the Company's gas and electric divisions.

## B. Cost of Debt

**Q WHAT COST OF DEBT IS THE COMPANY PROPOSING?**

A The Company is proposing an embedded cost of long-term debt of 4.35%.

[8]APSC Docket No. 21-170-U, Doc. No. 323, May 23, 2022, Order No. 14.
[9]*Id*. at 25.

**Q ARE YOU TAKING ISSUE WITH THE COMPANY'S PROPOSED COST OF DEBT?**

A No, I am not.

## C. Cost of Equity

**Q PLEASE DESCRIBE WHAT IS MEANT BY A "UTILITY'S COST OF COMMON EQUITY."**

A A utility's cost of common equity is the expected return that investors require on an investment in the utility. Investors expect to earn their required return from receiving dividends and through stock price appreciation. This rate is designed to ensure the utility can attract investment, maintain financial stability, and provide reliable service while balancing the interests of shareholders and ratepayers. Regulatory commissions set the ROE based on market conditions and the utility's specific risk profile.

**Q PLEASE DESCRIBE THE FRAMEWORK FOR DETERMINING A REGULATED UTILITY'S COST OF COMMON EQUITY.**

A In general, determining a fair cost of common equity for a regulated utility has been framed by two hallmark decisions of the U.S. Supreme Court ("Supreme Court"): Bluefield Water Works & Improvement Co. v. Pub. Serv. Comm'n of W. Va., 262 U.S. 679 (1923) and Fed. Power Comm'n v. Hope Natural Gas Co., 320 U.S. 591 (1944). In these decisions, the Supreme Court found that just compensation depends on many circumstances and must be determined by fair and enlightened judgments based on relevant facts. The Supreme Court also found that a utility is entitled to such rates as would permit it to earn a return on a property devoted to the convenience of the public that is generally consistent with the same returns available

in other investments of corresponding risk. The Supreme Court continued that the utility has "no constitutional rights to profits" such as those "realized or anticipated in highly profitable enterprises or speculative ventures,"[10] and defined the ratepayer/investor balance as follows:

> The return should be reasonably sufficient to assure confidence in the financial soundness of the utility and should be adequate, under efficient and economical management, to maintain and support its credit and enable it to raise the money necessary for the proper discharge of its public duties.[11]

As such, a fair ROR is based on the expectation that the utility's costs reflect efficient and economical management, and the return will support its credit standing and access to capital, but the return will not be in excess of this level. Utility rates that are consistent with these standards will be just and reasonable, and compensation to the utility will be fair and support financial integrity and credit-standing, under economic management of the utility.

**Q PLEASE DESCRIBE THE PROCESS YOU HAVE USED TO ESTIMATE CONSUMERS ENERGY'S COST OF COMMON EQUITY.**

A First, I assessed the market's perspective of Consumers Energy's risk. Then, I developed a proxy group of publicly traded utility companies that have similar risks and characteristics to Consumers Energy and compared potential differences in risks. I then performed several models based on financial theory to estimate Consumers Energy's cost of common equity. These models are: (1) a constant growth Discounted Cash Flow ("DCF") model using consensus analysts' growth rate projections; (2) a constant growth DCF model using sustainable growth rate

[10] *Bluefield,* 262 U.S. at 692-693.
[11] *Id*. at 693 (Emphasis Added).

estimates; (3) a multi-stage growth DCF model; (4) a Risk Premium model; and (5) a Capital Asset Pricing Model ("CAPM").

## D. Investment Risk Assessment of the Company

**Q PLEASE DESCRIBE THE MARKET'S ASSESSMENT OF CONSUMERS ENERGY'S INVESTMENT RISK.**

A The market's assessment of a company's investment risk is generally described by credit rating analysts' reports. The current credit ratings for Consumers Energy is A- from S&P and A3 from Moody's.[12] The Company's outlook from S&P and Moody's is considered "stable." In its August 2024 report covering Consumers Energy, S&P stated as follows:

> *We expect Consumers Energy Co. (CE) to continue to effectively manage its regulatory risk.*
>
> We believe Michigan's regulatory construct is above average compared with peers because of the benefit of a streamlined 10-month rate case process. Other constructive rate mechanisms include the use of forward test-years, power supply cost rider adjustments, and natural gas cost rider adjustments. These mechanisms help the company earn its allowed return on equity (ROE) and minimize regulatory lag.
>
> *Outlook*
>
> The stable rating outlook on CE reflects our expectation that management will focus on its core utility operations and reach constructive regulatory outcomes to avoid increasing business risk. We expect CE will maintain stand-alone financial measures consistent with the middle of the range for its financial risk profile category, specifically FFO to debt of 17%-19%.
>
> *Downside scenario*
>
> We could lower our rating on CE if: The stand-alone financial measures weaken such that FFO to debt weakens to consistently below 15%; or We lower our rating on parent CMS Energy.

[12]S&P Capital IQ, accessed on March 21, 2025.

*Upside scenario*

Although less likely, we could raise our rating on CE if we raise our rating on CMS Energy and CE's stand-alone financial measures improve, reflecting FFO to debt consistently above 20%.[13]

**Q HAVE EQUITY ANALYSTS COMMENTED ON THE COMPANY'S HISTORICAL AND EXPECTED FINANCIAL PERFORMANCE RECENTLY?**

A Yes. In a February note from an equity analyst covering the Company's parent, CMS Energy, an analysis by Barclays highlighted that CMS Energy has demonstrated strong financial performance, with a 13% ROE over the past twelve months. The analyst noted that CMS Energy could potentially over-earn the allowed ROE by approximately 100 basis points on the electric side and 50 basis points on the gas side due to energy efficiency initiatives and renewable energy investments.[14]

**Q WHAT IMPLICATIONS DOES THIS FINANCIAL PERFORMANCE HAVE FOR CONSUMERS ENERGY'S REQUESTED ROE?**

A The strong financial performance and potential to over-earn suggest that Consumers Energy's requested ROE of 10.25%, and even its currently authorized ROE of 9.9%, is likely higher than necessary to attract capital and maintain financial health. The Company's ability to achieve returns above the authorized ROE indicates that a lower ROE could still provide sufficient incentive for investment while reducing costs for ratepayers.

[13]S&P Capital IQ RatingsDirect, "Full Analysis: Consumers Energy Co.", August 20, 2024.
[14]https://www.investing.com/news/analyst-ratings/barclays-raises-cms-energy-stock-rating-lifts-target-to-75-93CH-3879851.

## E. Development of Proxy Group

**Q PLEASE BRIEFLY DESCRIBE WHY A PROXY GROUP IS NEEDED IN ESTIMATING THE COST OF EQUITY.**

A There are a few reasons why a proxy group is needed to estimate the cost of equity. As an initial matter, to be consistent with the *Hope* and *Bluefield* standards, as described above, the allowed return should be commensurate with returns on investments in other forms of comparable risk. A proxy group of similarly situated companies of comparable risk is needed to assess the Company's proposal under this standard.

Even if Consumers Energy were a publicly traded company whose securities could be used to estimate its cost of equity, there exists the potential for certain errors and biases which would make the reliance on a single estimate undesirable and potentially less accurate. A proxy group of comparable risk companies adds reliability to the estimates by mitigating the potential for bias that may be introduced by measurement errors of model inputs.

**Q PLEASE DESCRIBE HOW YOU IDENTIFIED A PROXY UTILITY GROUP THAT COULD BE USED TO ESTIMATE CONSUMERS ENERGY'S CURRENT MARKET COST OF EQUITY.**

A I started with the same group developed by Consumers Energy's witness Ms. Bulkley. I then reviewed each company to see if there were any significant changes between the date of Ms. Bulkley's analysis and the time of my analysis (i.e., March 21, 2025) that would potentially impact the risk level. Such factors would include significant merger and/or acquisition activity, credit ratings upgrades/downgrades, or dividend cuts. Based on my review, I found that one change was necessary to the proxy

group. Ms. Bulkley's proxy group included NiSource Inc. ("NiSource"), which was party to a transformative transaction, selling off a portion of its holdings in its vertically integrated electric utility company, NIPSCO. On June 20, 2023, NiSource announced that it has entered into a definitive agreement with an affiliate of Blackstone Infrastructure Partners, Blackstone's dedicated Infrastructure group, for the Blackstone Infrastructure affiliate to acquire a 19.9% equity interest in NIPSCO for $2.150 billion. NiSource closed on the divestiture in early 2024. At the time of the announcement, the announced value of the transaction represented nearly 20% of NiSource's market capitalization, making this a significant and transformative transaction. NiSource should not be included in the proxy group. This would leave only five proxy companies. In my opinion, I do not believe five companies represent a large enough sample to accurately measure the cost of equity.

I note that I had also considered the inclusion of Eversource Energy, a multi-utility with electric distribution, electric transmission, natural gas distribution, and water distribution segments. However, it has entered into a definitive agreement to sell its stake in Aquarion Water Company.

As such, in order to get a more thorough and complete analysis, I also included six additional water distribution utility companies. Therefore, my proxy group includes a total of 11 companies.

**Q HOW DOES THE INVESTMENT RISK OF CONSUMERS ENERGY COMPARE TO THAT OF THE PROXY GROUP?**

A As shown on my Exhibit AB-7, the proxy group has average credit ratings of A- and Baa1 from S&P and Moody's, respectively. The proxy group's average rating of A- from S&P is identical to Consumers Energy's rating of A- from S&P. The proxy

group's average rating of Baa1 from S&P is one notch lower than Consumers Energy's rating of A3 from Moody's.

As shown on the same exhibit, the proxy group has an average common equity ratio of 46.3% (including short-term debt) and 50.4% (excluding short-term debt) as calculated by *S&P Global Market Intelligence* and *Value Line*, respectively. Consumers Energy's requested common equity ratio of 50.75% significantly exceeds the proxy group's equity ratio as described above.

The Company's credit ratings are comparable to the proxy group, while its requested equity ratio of 50.75% exceeds the proxy group's equity ratio.

## F. DCF Model

**Q PLEASE DESCRIBE THE DCF MODEL.**

A The DCF model posits that a stock price equals the sum of the present value of expected future cash flows discounted at the investor's required ROR or cost of capital. This model is expressed mathematically as follows:

$$P_0 = \frac{D_1}{(1+K)^1} + \frac{D_2}{(1+K)^2} \ldots . \frac{D_\infty}{(1+K)^\infty} \qquad \text{(Equation 1)}$$

$P_0$ = Current stock price
D = Dividends in periods 1 - ∞
K = Investor's required return

This model can be rearranged in order to estimate the discount rate or investor-required return, known as "K." If it is reasonable to assume that earnings and dividends will grow at a constant rate, then Equation 1 can be rearranged as follows:

$$K = D_1/P_0 + G \qquad \text{(Equation 2)}$$

$K$ = Investor's required return
$D_1$ = Dividend in first year
$P_0$ = Current stock price
$G$ = Expected constant dividend growth rate

Equation 2 is referred to as the annual "constant growth" DCF model.

**Q PLEASE DESCRIBE THE INPUTS TO YOUR CONSTANT GROWTH DCF MODEL.**

A As shown in Equation 2 above, the DCF model requires a current stock price, the expected dividend, and the expected growth rate in dividends.

**Q WHAT STOCK PRICE HAVE YOU RELIED ON IN YOUR CONSTANT GROWTH DCF MODEL?**

A I relied on the average of the weekly high and low stock prices of the utilities in the proxy group over a 13-week period ending on March 21, 2025. An average stock price is less susceptible to market price variations than a price at a single point in time. Therefore, an average stock price is less susceptible to aberrant market price movements, which may not reflect the stock's long-term value.

**Q WHAT DIVIDEND DID YOU USE IN YOUR CONSTANT GROWTH DCF MODEL?**

A I used each proxy company's most recently paid quarterly dividend as reported in *Value Line*.[15] This dividend was annualized (multiplied by 4) and adjusted for next year's growth to produce the $D_1$ factor for use in Equation 2 above. In other words, I calculate $D_1$ by multiplying the annualized dividend ($D_0$) by (1+G).

[15]The Value Line Investment Survey, January 3 and February 21, 2025.

**Q WHAT DIVIDEND GROWTH RATES HAVE YOU USED IN YOUR CONSTANT GROWTH DCF MODEL?**

A There are several methods that can be used to estimate the expected growth in dividends. However, regardless of the method, for purposes of determining the market-required return on common equity, one must attempt to estimate investors' expectations about what the dividend, or earnings growth rate, will be, and not what an individual investor or analyst may use to make individual investment decisions.

As predictors of future returns, securities analysts' growth estimates have been shown to be more accurate than growth rates derived from historical data.[16] That is, assuming the market generally makes rational investment decisions, analysts' growth projections are more likely to influence investors' decisions, which are captured in observable stock prices, than growth rates derived only from historical data.

For my constant growth DCF analysis, I have relied on a consensus, or mean, of professional securities analysts' earnings growth estimates as a proxy for investors' dividend growth rate expectations. I used the average of analysts' growth rate estimates from three sources: Zacks, S&P Capital IQ Market Intelligence ("MI"), and Institutional Brokers' Estimate System ("I/B/E/S") from LSEG Workspace. All such projections were available on March 21, 2025, and all were reported online.[17]

Each growth rate projection is based on a survey of independent securities analysts. There is no clear evidence whether a particular analyst is most influential on general market investors. Therefore, a single analyst's projection does not predict investor outlooks as reliably as does a consensus of market analysts' projections. The consensus of estimates is a simple arithmetic average, or mean, of surveyed

[16] *See*, e.g., David Gordon, Myron Gordon, and Lawrence Gould, Choice Among Methods of Estimating Share Yield, The Journal of Portfolio Management, Spring 1989.

[17] www.zacks.com; LSEG Workspace; https://www.capitaliq.spglobal.com/.

analysts' earnings growth forecasts. A simple average of the growth forecasts gives equal weight to all surveyed analysts' projections. Therefore, a simple average, or arithmetic mean, of analysts' forecasts is a good proxy for investor expectations.

The growth rates I used in my DCF analysis are shown in Exhibit AB-8. The average growth rate for my proxy group is 10.03% and a median growth rate of 7.18%.

**Q WHAT ARE THE RESULTS OF YOUR CONSTANT GROWTH DCF MODEL?**

A As shown in Exhibit AB-9, page 1, the average and median constant growth DCF returns for my proxy group for the 13-week analysis are 13.54% and 10.74%, respectively.

**Q ARE THERE LIMITATIONS OF THE CONSTANT GROWTH DCF ANALYSIS?**

A Yes. The constant growth DCF analysis for my proxy group is based on a group average long-term growth rate of 10.03%. The three- to five-year growth rates are approximately 142% higher than the long-term projected GDP growth rate of 4.14%, described below. As I explain in detail below, a utility's growth rate cannot exceed the growth rate of the economy in which it provides services in perpetuity, which is the time period assumed by the DCF model.

**Q HOW DID YOU IDENTIFY THE LONG-TERM PROJECTED GDP GROWTH RATE?**

A Although there may be short-term peaks, the long-term sustainable growth rate for a utility stock cannot exceed the growth rate of the economy in which it sells its goods and services. The long-term maximum sustainable growth rate for a utility investment is limited by the projected long-term GDP growth rate, as that reflects the projected

long-term growth rate of the economy. The consensus projection for U.S. GDP, as published by Blue Chip Economic Indicators, is an annual growth rate of approximately 4.14% over the next 10 years. In my opinion, this is a reasonable proxy of long-term growth.

Later in this testimony, I discuss academic and investment-practitioner support for using the projected long-term GDP growth outlook as a maximum long-term growth rate projection. Using the long-term GDP growth rate as a conservative projection for the maximum growth rate is logical and is generally consistent with academic and practitioner accepted practices.

## G. Sustainable Growth DCF

**Q PLEASE DESCRIBE WHAT THE SUSTAINABLE GROWTH DCF METHOD IS AND HOW YOU ESTIMATED A SUSTAINABLE GROWTH RATE FOR YOUR SUSTAINABLE GROWTH DCF MODEL.**

A The sustainable growth rate, also referred to as the internal growth rate, is determined by the proportion of the utility's earnings that is retained and reinvested in its plant and equipment. These reinvested earnings enhance the earnings base, also known as the rate base. The earnings grow as the plant, funded by the reinvested earnings, is put into operation, allowing the utility to receive its authorized return on the additional rate base investment.

The internal growth approach is linked to the percentage of earnings retained within the company, as opposed to being paid out as dividends. The earnings retention ratio is calculated as 1 minus the dividend payout ratio. As the payout ratio decreases, the retention ratio increases, leading to stronger growth as the company funds more investments using retained earnings.

The payout ratios of the proxy group are shown in my Exhibit AB-10. These dividend-payout ratios and earnings-retention ratios then can be used to develop a long-term growth rate driven by earnings retention.

The data used to estimate the long-term sustainable growth rate is based on the Company's current market-to-book ratio and on *Value Line*'s three- to five-year projections of earnings, dividends, earned returns on book equity, and stock issuances.

As shown in Exhibit AB-11, the average and median sustainable growth rates for the proxy group using this internal growth rate model are 5.32% and 4.93%, respectively.

**Q WHAT IS THE DCF ESTIMATE USING THESE SUSTAINABLE GROWTH RATES?**

A A DCF estimate based on these sustainable growth rates is developed in Exhibit AB-12. As shown there, and using the same formula in Equation 2 above, a sustainable growth DCF analysis produces proxy group average and median DCF results for the 13-week period of 8.70% and 8.38%, respectively.

## H. Multi-Stage Growth DCF Model

**Q HAVE YOU CONDUCTED ANY OTHER DCF STUDIES?**

A Yes. As previously noted, the DCF model is intended to represent the present value of an endless series of future cash flows. Nevertheless, the initial constant growth DCF that I created is based on analyst growth-rate projections, providing a plausible representation of rational investment expectations over the next three-to-five years. The limitation of this constant growth DCF model is that it cannot reflect a reasonable expectation of a shift in growth from a high or low short-term rate to a rate that aligns

more with long-term sustainable growth. To accommodate changing growth expectations, I conducted a multi-stage DCF analysis that reflects growth rate change over time.

**Q WHY DO YOU BELIEVE GROWTH RATES CAN CHANGE OVER TIME?**

A The growth rate projections by analysts for the next three-to-five years are subject to change as the outlook for utility earnings-growth evolves. Utility companies experience fluctuations in their investment cycles. When these companies are undertaking substantial investments, the growth of their rate base accelerates, leading to an increase in earnings growth. However, once a major construction cycle reaches completion or plateaus, the growth in the utility rate base slows down, and its earnings growth rate declines from an abnormally high three-to-five year rate to a lower, sustainable growth rate.

As construction cycles become longer in duration, even with an aggressive construction plan, the growth rate of the utility will naturally slow due to a decrease in rate base growth as the utility has limited human and capital resources to expand its construction activities. Therefore, the three-to-five year growth rate projection should be viewed as a long-term sustainable growth rate, but not without considering the current market conditions, industry trends, and determining whether the three-to-five year growth outlook is feasible and sustainable.

**Q PLEASE DESCRIBE YOUR MULTI-STAGE DCF MODEL.**

A The multi-stage DCF model reflects the possibility of non-constant growth for a company over time. The multi-stage DCF model reflects three growth periods: (1) a short-term growth period consisting of the first five years; (2) a transition period,

consisting of the next five years (6 through 10); and (3) a long-term growth period starting in year 11 and extending into perpetuity.

For the short-term growth period, I relied on the consensus of analysts' growth projections described above in relationship to my constant growth DCF model. For the transition period, the growth rates were reduced or increased by an equal factor reflecting the difference between the analysts' growth rates and the long-term sustainable growth rate. For the long-term growth period, I assumed each company's growth would converge to the maximum sustainable long-term growth rate.

**Q WHY IS THE GDP GROWTH PROJECTION A REASONABLE PROXY FOR THE MAXIMUM SUSTAINABLE LONG-TERM GROWTH RATE?**

A As discussed above, utilities cannot indefinitely sustain a growth rate that exceeds the growth rate of the economy in which they sell services. A utilities' earnings and dividend growth is created by increased utility investment in its rate base. Examples of what can drive such investment are: service area economic growth, system reliability upgrades, or state and federal green energy initiatives. As such, nominal GDP growth is a reasonable upper limit for utility sales growth, rate base growth, and earnings growth in the long-run. Therefore, the U.S. GDP nominal growth rate is a conservative proxy for the highest sustainable long-term growth rate of a utility.

**Q IS THERE RESEARCH THAT SUPPORTS YOUR POSITION THAT, OVER THE LONG TERM, A COMPANY'S EARNINGS AND DIVIDENDS CANNOT GROW AT A RATE GREATER THAN THE RATE OF GROWTH OF THE U.S. GDP?**

A Yes. This concept is supported in published analyst literature and academic work. Specifically, in a textbook titled *Fundamentals of Financial Management*, published by Eugene Brigham and Joel F. Houston, the authors state as follows:

> The constant growth model is most appropriate for mature companies with a stable history of growth and stable future expectations. Expected growth rates vary somewhat among companies, but dividends for mature firms are often expected to grow in the future at about the same rate as nominal gross domestic product (real GDP plus inflation).[18]

The use of the economic growth rate is also supported by investment practitioners as outlined as follows:

> **Estimating Growth Rates**
>
> One of the advantages of a three-stage discounted cash flow model is that it fits with life cycle theories in regards to company growth. In these theories, companies are assumed to have a life cycle with varying growth characteristics. Typically, the potential for extraordinary growth in the near term eases over time and eventually growth slows to a more stable level.
>
> * * *
>
> Another approach to estimating long-term growth rates is to focus on estimating the overall economic growth rate. Again, this is the approach used in the *Ibbotson Cost of Capital Yearbook*. To obtain the economic growth rate, a forecast is made of the growth rate's component parts. Expected growth can be broken into two main parts: expected inflation and expected real growth. By analyzing these components separately, it is easier to see the factors that drive growth.[19]

[18] *Fundamentals of Financial Management*, Eugene F. Brigham and Joel F. Houston, Eleventh Edition 2007, Thomson South-Western, a Division of Thomson Corporation at 298 (Emphasis Added).

[19] Morningstar, Inc., Ibbotson SBBI 2013 Valuation Yearbook at 51 and 52.

**Q HOW DID YOU DETERMINE A LONG-TERM GROWTH RATE THAT REFLECTS THE CURRENT CONSENSUS OF INDEPENDENT MARKET PARTICIPANTS?**

A I relied on the consensus of long-term GDP growth projections as projected by independent economists. Blue Chip Economic Indicators publishes the consensus for GDP growth projections twice a year. These projections reflect current outlooks for GDP and are likely to be influential on investors' expectations of future growth outlooks. The consensus of projected GDP growth is about 4.14% over the next 10 years.[20]

**Q DO YOU CONSIDER OTHER SOURCES OF PROJECTED LONG-TERM GDP GROWTH?**

A Yes, and these alternative sources corroborate the consensus analysts' projections I relied on. Several projections are shown in Table CCW-7 below.

[20]Blue Chip Economic Indicators, March 10, 2025 at page 14.

**TABLE CCW-7**

**GDP Forecasts**

| Source | Projected Period | Real GDP | Inflation | Nominal GDP |
|---|---|---|---|---|
| Blue Chip Economic Indicators [1] | 5-10 Yrs | 1.9% | 2.2% | 4.1% |
| EIA - Annual Energy Outlook[2] | 27 Yrs | 1.9% | 2.3% | 4.3% |
| Congressional Budget Office[3] | 30 Yrs | 1.7% | 2.0% | 3.8% |
| Moody's Analytics[4] | 31 Yrs | 2.0% | 2.1% | 4.1% |
| Social Security Administration[5] | 76 Yrs | 1.6% | 2.4% | 4.0% |
| Economist Intelligence Unit[6] | 31 Yrs | 1.6% | 2.3% | 3.9% |

Sources:
[1]Blue Chip Economic Indicators, March 10, 2025 at 14.
[2]U.S. EnergyInformation Administration (EIA), Annual Energy Outlook 2023, September, 2022.
[3]Congressional Budget Office, Long-Term Budget Outlook, March 28, 2024.
[4]Moody's Analytics Forecast, last updated January 13, 2025.
[5]Social Security Administration, "2024 OASDI Trustees Report," Table VI.G6. May 6, 2024.
[6]S&P MI, Economist Intelligence Unit, downloaded on March 4, 2025.

As shown in the table above, the real GDP and inflation fall in the range of 1.6% to 2.0% and 2.0% to 2.4%, respectively. This results in a nominal GDP in the range of 3.8% to 4.3%. Therefore, the nominal GDP growth projections made by these independent sources support my use of 4.14% as a reasonable estimate of market participants' expectations for long-term GDP growth. The real GDP and nominal GDP growth projections made by these independent sources support my use of 4.14% as a reasonable estimate of market participants' expectations for long-term GDP growth.

**Q WHAT STOCK PRICE, DIVIDEND, AND GROWTH RATES DID YOU USE IN YOUR MULTI-STAGE DCF ANALYSIS?**

A I relied on the same 13-week average stock prices and the most recent quarterly dividend payment data discussed above. For the first stage, I used the consensus of analysts' growth rate projections discussed above in my constant growth DCF model. The first stage covers the first five years, consistent with the time horizon of the securities analysts' growth rate projections. The second stage, or transition stage, begins in year 6 and extends through year 10. The second stage growth transitions the growth rate from the first stage to the third stage using a straight linear trend. For the third stage, or long-term sustainable growth stage, starting in year 11, I used a 4.14% long-term sustainable growth rate based on the consensus of economists' long-term projected nominal GDP growth rate.

**Q WHAT ARE THE RESULTS OF YOUR MULTI-STAGE DCF MODEL?**

A As shown in Exhibit AB-13, the average and median DCF ROEs for my proxy group using the 13-week average stock price are 9.26% and 8.47%, respectively.

**Q PLEASE SUMMARIZE THE RESULTS FROM YOUR DCF ANALYSES.**

A The DCF results are summarized in Table CCW-8 below. As described above, the results of the constant growth DCF using analysts' growth rates assume an average long-term growth rate of 10.03%, which is approximately 142% higher than the long-term projected GDP growth rate of 4.14%. This is an unsustainable assumption, and likely leads to an overstatement in the cost of equity for a low risk regulated utility. As such, it is my opinion that more weight should be given to the sustainable growth and multi-stage models of the DCF.

**Table CCW-8**

**Summary of DCF Results**

| Description | Proxy Group Mean | Proxy Group Median |
|---|---|---|
| Constant Growth DCF Model (Analysts' Growth) | 13.54% | 10.74% |
| Constant Growth DCF Model (Sustainable Growth) | 8.70% | 8.38% |
| Multi-Stage DCF Model | 9.26% | 8.47% |

## I. Risk Premium Model

**Q PLEASE DESCRIBE YOUR BOND YIELD PLUS RISK PREMIUM MODEL.**

A This model is based on the principle that investors require a higher return to assume greater risk. Common equity investments have greater risk than bonds because bonds have more security of payment in bankruptcy proceedings than common equity and the coupon payments on bonds represent contractual obligations. In contrast, companies are not required to pay dividends or guarantee returns on common equity investments. Therefore, common equity securities are riskier than bond securities.

This risk premium model is based on two estimates of an equity risk premium. First, I quantify the difference between regulatory commission-authorized returns on common equity and contemporary U.S. Treasury bonds. The difference between the authorized return on common equity and the Treasury bond yield is the risk premium. I estimated the risk premium on an annual basis for each year since January 1986. The authorized ROEs were based on regulatory commission-authorized returns for

utility companies. Authorized returns are typically based on expert witnesses' estimates of the investor-required return at the time of the proceeding.

The second equity risk premium estimate is based on the difference between regulatory commission-authorized returns on common equity and contemporary "A" rated utility bond yields by Moody's. I selected the period beginning in 1986 because public utility stocks consistently traded at a premium to book value during that period. This is illustrated in Exhibit AB-14, which shows the market-to-book ratio since 1986 for the utility industry was consistently above a multiple of 1.0x. Over this period, an analyst can infer that authorized ROEs were sufficient to support market prices that at least exceeded book value. This is an indication that commission-authorized returns on common equity supported a utility's ability to issue additional common stock without diluting existing shares. It further demonstrates that utilities were able to access equity markets without a detrimental impact on current shareholders.

Based on this analysis, as shown in Exhibit AB-15, the average indicated equity risk premium over U.S. Treasury bond yields has been 5.63%. Since the risk premium can vary depending upon market conditions and changing investor risk perceptions, I believe using an estimated range of risk premiums provides the best method to measure the current return on common equity for a risk premium methodology.

In addition, I assessed the five-year and ten-year rolling average risk premiums over the study period to gauge the variability over time. These rolling average risk premiums mitigate the impact of anomalous market conditions and skewed risk premiums over an entire business cycle. As shown on my Exhibit AB-15,

the five-year rolling average risk premium over Treasury bonds ranged from 4.17% to 7.17%, while the ten-year rolling average risk premium ranged from 4.30% to 6.92%.

As shown on my Exhibit AB-16, the average indicated equity risk premium over contemporary "A" rated Moody's utility bond yields was 4.27%. The five-year and ten-year rolling average risk premiums ranged from 2.80% to 5.98% and 3.11% to 5.75%, respectively.

**Q WHY IS THE TIME PERIOD USED TO DERIVE THESE EQUITY RISK PREMIUM ESTIMATES APPROPRIATE TO FORM ACCURATE CONCLUSIONS ABOUT CONTEMPORARY MARKET CONDITIONS?**

A Contemporary market conditions can change dramatically during the period that rates determined in this proceeding will be in effect. A relatively long period of time where stock valuations reflect premiums to book value indicates that the authorized ROEs and the corresponding equity risk premiums were supportive of investors' return expectations and provided utilities access to the equity markets under reasonable terms and conditions. Further, this period is long enough to smooth abnormal market movement that might distort equity risk premiums. While market conditions and risk premiums do vary over time, this historical period is a reasonable period to estimate contemporary risk premiums.

**Q PLEASE EXPLAIN OTHER MARKET EVIDENCE YOU RELIED ON IN DETERMINING AN APPROPRIATE EQUITY RISK PREMIUM.**

A The equity risk premium should reflect the market's perception of risk in the utility industry today. I have gauged investor perceptions in utility risk today in Exhibit AB-17, where I show the yield-spread between utility bonds and Treasury bonds

since 1980. As shown in this schedule, the average utility bond yield-spreads over Treasury bonds for "A" and "Baa" rated utility bonds for this historical period are 1.48% and 1.90%, respectively.

A current three-month average "A" rated utility bond yield of 5.51% when compared to the current Treasury bond yield of 4.50%, as shown in Exhibit AB-18, page 1, implies a yield-spread of 1.01%. This current utility bond yield-spread is lower than the long-term average-spread for "A" rated utility bonds of 1.48%. The three-month average yield on "Baa" rated utility bonds is 5.71%. This indicates a current spread for the "Baa" rated utility bond yield of 1.21%, which is lower than the long-term average of 1.90%.

**Q WHAT ARE THE RESULTS BASED ON YOUR RISK PREMIUM ANALYSES?**

A I give primary consideration to the Risk Premium results using Treasury bonds and A-rated utility bonds. My recommendation also takes the results of adding the Baa-rated utility bond yield to the equity risk premium over A-rated utility bonds into consideration.

Considering the current and projected economic environment, current yield-spreads and equity risk premiums, as well as current levels of interest rates and interest rate projections, a more normalized equity risk premium is warranted. As such, I believe an average equity risk premium over Treasury yields of 5.63% is appropriate. Adding this risk premium to the most recent consensus projected Treasury yield of 4.60%[21] produces a ROE of 10.23%.

Applying a similar methodology as described above, the average risk premium over A-rated utility bonds is 4.27%. The A-rated utility bond yield has averaged

[21]Blue Chip Financial Forecast, February 28, 2025.

5.51% over the three-month period through December 2024 while the Baa-rated utility bond yield has averaged 5.71% over the same period. Adding the average equity risk premium of 4.27% to the three-month average A-rated utility bond yield of 5.51% produces an estimated cost of equity of 9.78%. Adding the same equity risk premium to the three-month average Baa-rated utility bond yield of 5.71% produces an estimated cost of equity of 9.98%.

The A-rated utility bond yield has averaged 5.46% over the six-month period ending December 2024 while the Baa-rated utility bond yield has averaged 5.67% over the same period. Adding the average equity risk premium of 4.27% to the six-month average A-rated utility bond yield of 5.46% produces an estimated cost of equity of 9.73%. Adding the equity risk premium of 4.27% to the six-month average Baa-rated utility bond yield of 5.67% produces an estimated cost of equity of 9.94%.

The results of my risk premium analyses are summarized in Table CCW-9.

**Table CCW-9**

**Summary of Risk Premium Results**

| Description | Results |
|---|---|
| Projected Treasury Yield | 10.23% |
| 3-Month Average Yields | |
| A-Rated Utility Bond | 9.78% |
| Baa-Rated Utility Bond | 9.98% |
| 6-Month Average Yields | |
| A-Rated Utility Bond | 9.73% |
| Baa-Rated Utility Bond | 9.94% |

## J. Capital Asset Pricing Model

**Q PLEASE DESCRIBE THE CAPM.**

A The CAPM method of analysis is based upon the theory that the market-required ROR for a security is equal to the risk-free rate, plus a risk premium associated with the specific security. This relationship between risk and return can be expressed mathematically as follows:

$R_i = R_f + B_i \times (R_m - R_f)$ where:

$R_i$ = Required return for stock i
$R_f$ = Risk-free rate
$R_m$ = Expected return for the market portfolio
$B_i$ = Beta - Measure of the risk for stock

The term "beta" in the equation represents the stock-specific risk that cannot be reduced through diversification. In a well-diversified portfolio, specific risks related to individual stocks can be reduced by balancing the portfolio with securities that offset the impact of firm-specific factors, such as business cycle, competition, product mix, and production limitations.

Non-diversifiable risks, on the other hand, are related to market conditions and are referred to as systematic risks. These risks cannot be reduced through diversification and are considered market risks. Conversely, non-systematic risks, also known as business risks, can be reduced through diversification.

According to the CAPM, the market does not compensate investors for taking on risks that can be diversified away. Thus, investors are only compensated for taking on systematic, or non-diversifiable, risks. Beta is a measure of these systematic risks.

**Q PLEASE DESCRIBE THE INPUTS TO YOUR CAPM.**

A The CAPM requires an estimate of the market risk-free rate, the company's beta, and the Market Risk Premium ("MRP"). The MRP is the difference between the expected market return and the risk-free rate.

**Q WHAT DID YOU USE AS AN ESTIMATE OF THE MARKET RISK-FREE RATE?**

A As previously noted, *Blue Chip Financial Forecasts*' projected 30-year Treasury bond yield is 4.60%.[22] The current 30-year Treasury bond yield is 4.50%, as shown in Exhibit AB-18 at page 1. I used *Blue Chip Financial Forecasts*' projected 30-year Treasury bond yield of 4.60% for my CAPM analysis.

**Q WHAT BETA DID YOU USE IN YOUR ANALYSIS?**

A As shown in Exhibit AB-19, the current proxy group average and median *Value Line* beta estimates are 0.88 and 0.90, respectively. In my experience, these beta estimates are abnormally high and are unlikely to be sustained over the long-term. As such, I have also reviewed the historical average of the proxy group's *Value Line* betas. As shown on Exhibit AB-19, the historical average *Value Line* beta since 2014 is 0.76 and has ranged from 0.65 to 0.88. Prior to the recent pandemic, the high end of this range was 0.75.

In addition to *Value Line*, I have also included adjusted beta estimates as provided by Market Intelligence's Beta Generator Model. This model relied on a five-year period on a weekly basis ending March 21, 2025. The average and median Market Intelligence betas are 0.68 and 0.66, respectively. Market Intelligence betas, as calculated using its Beta Generator Model, are adjusted using the Vasicek method

[22]Blue Chip Financial Forecast, February 28, 2025.

and calculated using the S&P 500 as the proxy for the investable market. This is in stark contrast with the *Value Line* beta estimates that are adjusted using a constant weighting of 67%/35% to the raw beta/market beta and use the New York Stock Exchange ("NYSE") as the proxy for the investable market. Because I rely on the S&P 500 to estimate the expected return on the investable market, it makes sense to rely on beta estimates that are calculated using the S&P 500 as the benchmark for the market. Further, as S&P explains:

> The Vasicek Method is a superior alternative to the Bloomberg Beta adjustment. The Bloomberg adjustment is not appropriate for a vast number of situations, as it assigns constant weighting regardless of the standard error in the raw beta estimation (Bloomberg Beta = 1/3*market beta + 2/3*Raw Beta). Given the statistical fact that a larger sample size yields a smaller error, the Vasicek method more appropriately adjusts the raw beta via weights determined by the variance of the individual security versus the variance of a larger sample of comparable companies. The weights are designed to bring the raw beta closer to whichever beta estimation has the smallest error. This is a feature the Bloomberg beta cannot replicate.[23]

Notably, while S&P makes reference to the Bloomberg method of applying 2/3 and 1/3 weights to the raw beta and market beta, respectively, the comparison still applies to *Value Line's* methodology of applying 67% and 35% weights. Both methods are forms of the Blume adjustment.[24] While the weights are slightly different between the Bloomberg and *Value Line* methods, they are similar and apply a constant weight without any regard to accuracy. As such, S&P's criticisms apply to both Bloomberg betas and *Value Line* betas.

Because current beta estimates are based on the most recent five years of historical stock returns and volatility, they are being heavily impacted by the market

[23]S&P Market Intelligence, Beta Generator Model.

[24]The Blume adjustment is a tool used to refine a beta measurement in finance. In general, beta attempts to explain how much a particular investment's price moves compared to the overall market. But beta is often based on historical data, which may not be an accurate method for predicting the future. The Blume adjustment tries to address this by considering the idea that, in the long run, most investments tend to become more similar in their riskiness to the overall market (represented by a beta of 1).

fallout in early 2020 as the global pandemic set in and the market reacted, with this S&P 500 falling more than 40%. For this reason, it is not reasonable to assume current beta estimates, particularly Blume-adjusted betas such as those published by *Value Line*, are reflective of investor expectations at this time.

**Q YOU MENTION THAT THE CURRENT 5-YEAR VALUE LINE BETA ESTIMATES MIGHT NOT BE REFLECTIVE OF INVESTOR EXPECTATIONS, AND POTENTIALLY OVERSTATE THE COST OF EQUITY. DO YOU HAVE EVIDENCE TO SUPPORT THAT HYPOTHESIS?**

A Yes. As mentioned above, Value Line's beta estimates calculated over a 5-year historical price period will include the unprecedented volatility and market prices caused by the onset of the COVID-19 pandemic in early 2020. It is unreasonable to assume that those prices and resulting volatility resemble investor expectations going forward. Prior to the market fallout from the pandemic, utility beta estimates were at several year lows. Subsequent to the period of peak volatility from the pandemic, utility betas have actually declined back toward their normalized levels. This is demonstrated in Table CCW-10 below. In this table, I present the raw unadjusted beta estimates for *Value Line's* reported 5-year period as well as a 3-year period ending March 21, 2025. I then apply the Blume adjustment using the same weighting applied by *Value Line*.[25]

[25]The Value Line method to calculated adjusted betas is as follows: $B_{adjusted} = 0.35 + 0.67 \times B_{unadjusted}$.

**Table CCW-10**

**Beta Comparison**

| Proxy Group | 5-Year Value Line Beta[1] | | 3-Year Beta[2] | |
|---|---|---|---|---|
| | Unadjusted | Reported | Unadjusted | Adjusted[4] |
| Atmos Energy Corporation | 0.82 | 0.90 | 0.61 | 0.76 |
| Northwest Natural Holding Company | 0.82 | 0.90 | 0.66 | 0.79 |
| ONE Gas, Inc. | 0.75 | 0.85 | 0.60 | 0.75 |
| Southwest Gas Holdings, Inc. | 0.90 | 0.95 | 0.65 | 0.79 |
| Spire Inc. | 0.82 | 0.90 | 0.60 | 0.76 |
| American States Water Company | 0.60 | 0.75 | 0.64 | 0.78 |
| American Water Works Company, Inc. | 0.97 | 1.00 | 0.77 | 0.87 |
| California Water Service Group | 0.60 | 0.75 | 0.71 | 0.83 |
| Essential Utilities, Inc. | 0.97 | 1.00 | 0.68 | 0.81 |
| Middlesex Water Company | 0.67 | 0.80 | 0.63 | 0.77 |
| SJW Group | 0.75 | 0.85 | 0.61 | 0.76 |
| Average | 0.79 | 0.88 | 0.65 | 0.79 |
| Median | 0.82 | 0.90 | 0.64 | 0.78 |

Source:
[1]The Value Line Investment Survey, January 3 and February 21, 2025.
[2]S&P Global Market Intelligence, betas for the period 3/21/2022 - 3/21/2025.
[4]Estimated the unadjusted beta by removing Value Line's Blume adjustment methodology: (Unadjusted Beta - 0.35) / 0.67
[4]Adjusted using Value Line's Blume adjustment methodology: 0.35+(0.67 x Unadjusted Beta)

This data clearly demonstrates that systematic market risk has subsided for regulated utilities after controlling for the impacts of the global pandemic with average and median beta estimates of 0.79 and 0.78, respectively.

**Q HOW DID YOU DERIVE YOUR MRP ESTIMATES?**

A My MRP estimates are derived using two general approaches: a risk premium approach and a DCF approach. I also consider the normalized MRP of 5.00% with the normalized risk-free rate of 4.78% as recommended by Kroll, formerly known as

Duff & Phelps.[26] Based on this methodology and utilizing a "normalized" risk-free rate of 4.78%, Kroll concludes that the current expected, or forward-looking, MRP is 5.00%, implying an expected return on the market of 9.78%.[27]

**Q PLEASE DESCRIBE YOUR MRP ESTIMATE DERIVED USING THE RISK PREMIUM METHODOLOGY.**

A The forward-looking risk premium-based estimate was derived by estimating the expected return on the market (as represented by the S&P 500) and subtracting the risk-free rate from this estimate. I estimated the expected return on the S&P 500 by adding an expected inflation rate to the long-term historical arithmetic average real return on the market. The real return on the market represents the achieved return above the rate of inflation.

Morningstar Direct calculates the historical arithmetic-average real-market return over the period 1926 to 2023 to be 9.02%.[28] A current consensus for projected inflation is 2.50%.[29] Using these estimates, the expected market return is 11.75%.[30] The MRP then is the difference between the 11.75% expected market return and the projected risk-free rate of 4.60%, or 7.10%.

[26]Kroll, and its predecessor Duff & Phelps, is a provider of economic, financial, and valuation data that is often relied on by finance professionals and cited in ROR testimony.

[27]Kroll, *Kroll Increases U.S. Normalized Risk-Free Rate from 3.0% to 3.5%, but Spot 20-Year U.S. Treasury Yield Preferred When Higher* (Jun. 16, 2022). The current 20-year yield of 4.78% exceeds the "normalized" yield of 3.5%. In accordance with Kroll's prescribed method, the greater of the two shall be used under the normalized Kroll methodology, i.e., 4.78%.

[28]Morningstar Direct, data through 2023.

[29]Blue Chip Financial Forecast February 28, 2025.

[30][(1 + 9.02%) ∗ (1 + 2.50%) - 1] ∗ 100.

**Q PLEASE DESCRIBE YOUR MRP ESTIMATES DERIVED USING THE DCF METHODOLOGY.**

A I employed two versions of the constant growth DCF model to develop estimates of the MRP. I first employed the Federal Energy Regulatory Commission's ("FERC") method of estimating the expected return on the market that was established in its Opinion No. 569-A. FERC's method for estimating the expected return on the market is to perform a constant growth DCF analysis on each of the dividend-paying companies of the S&P 500 index. The growth rate component is based on the average of the growth projections excluding companies with growth rates that were negative or greater than 20%.[31] The weighted average growth rate for the remaining companies is 10.50%.[32] After reflecting the FERC prescribed method of adjusting the dividend yield by (1 + 0.5g), the weighted average expected dividend yield is 1.79%. Thus, the DCF-derived expected return on the market is the sum of those two components, or 12.29%. The MRP then is the expected market return of 12.29%, less the projected risk-free rate of 4.60%, or approximately 7.70%.

My second DCF-based MRP estimate was derived by performing the same DCF analysis described above, except I used all companies in the S&P 500 index rather than just the dividend-paying companies. The weighted average growth rate for these companies is 10.90%.[33] After reflecting the FERC-prescribed method of adjusting the dividend yield by (1 + 0.5g), the weighted average expected dividend yield is 1.58%. Thus, the DCF-derived expected return on the market is the sum of those two components, or 12.48%. The MRP then is the expected market return of 12.48% less the projected risk-free rate of 4.60%, or approximately 7.90%.

[31]Opinion No. 569-A, at 210.
[32]Exhibit AB-20 at page 2.
[33]*Id*.

The average expected market return based on the DCF model is 12.39% and the average MRP based on the two DCF estimates is 7.80%.

**Q HOW DO YOUR EXPECTED MARKET RETURNS COMPARE TO CURRENT EXPECTATIONS OF FINANCIAL INSTITUTIONS?**

A As shown in Table CCW-11, my average expected market return of 11.31%[34] exceeds long-term market expectations of several financial institutions.

**TABLE CCW-11**

**Long-Term Expected Return on the Market**

| Source | Term | Expected Return Large Cap Equities |
|---|---|---|
| BlackRock Capital Management[1] | 30 Years | 7.00% |
| JP Morgan Chase[2] | 10 - 15 Years | 7.00% |
| Vanguard[3] | 10 Years | 4.2% - 6.2% |
| Research Affiliates[4] | 10 Years | 4.00% |

Sources:
[1]BlackRock Investment Institute.
[2]JP Morgan Chase, Long-Term Capital Market Assumptions, 2024 Report.
[3]Vanguard economic and market outlook.
[4]Research Affiliates, Asset Allocation Interactive.

When compared to the expected market returns of financial institutions above, my average expected market return of 11.31% is greater than all of them. For these

[34]11.31% = (9.78% + 12.39% + 11.75%) / 3.

reasons, my expected market returns, and the associated MRPs, should be considered reasonable, if not high-end estimates.

**Q HOW DO YOUR ESTIMATED MRPs COMPARE TO THAT ESTIMATED BY KROLL?**

A On its Cost of Capital portal, Kroll's MRP falls somewhere in the range of 5.00% to 7.17%. My MRP estimates are in the range of 5.00% to 7.80%.

**Q HOW DOES KROLL MEASURE A MRP?**

A Kroll's range is based on several methodologies. First, Kroll estimated a MRP of 7.17% based on the difference between the total market return on common stocks (S&P 500) less the income return on 20-year Treasury bond investments over the 1926-2023 period.[35]

Second, Kroll used the Ibbotson & Chen supply-side model which produced a MRP estimate of 6.22%.[36] Kroll explains that the historical MRP based on the S&P 500 was influenced by an abnormal expansion of P/E ratios relative to earnings and dividend growth. To control for the volatility of extraordinary events and their impacts on P/E ratios, Kroll takes into consideration the three-year average P/E ratio as the current P/E ratio. Therefore, Kroll adjusted this MRP estimate to normalize the growth in the P/E ratio to be more in line with the growth in dividends and earnings.

Finally, Kroll developed its own recommended equity, or MRP, by employing an analysis that takes into consideration a wide range of economic information, multiple risk premium estimation methodologies, and the current state of the economy by observing measures such as the level of stock indices and corporate spreads as

[35]Kroll Cost of Capital Navigator.
[36]*Id.*

indicators of perceived risk. Based on this methodology, and utilizing a "normalized" risk-free rate of 4.78%, Kroll concludes that the current expected, or forward-looking, MRP is 5.00%, implying an expected return on the market of 9.78%.[37]

**Q WHAT ARE THE RESULTS OF YOUR CAPM ANALYSIS?**

A As shown in Exhibit AB-20, I have provided the results of twelve different applications of the CAPM. The first three results presented are based on the proxy group's current average *Value Line* beta of 0.88. The results of the CAPM based on these inputs range from 9.17% to 11.44%.

The next set of three results presented are based on the proxy group's historical *Value Line* beta of 0.76. The results of the CAPM based on these inputs range from 8.57% to 10.51%.

The third set of results presented are based on the proxy group's current *S&P Global Market Intelligence* beta of 0.68. The results of the CAPM based on these inputs range from 8.19% to 9.92%.

The final set of results presented are based on the proxy group's three-year beta estimate of 0.79. The results of the CAPM based on these inputs range from 8.72% to 10.74%.

My CAPM results are summarized in Table CCW-12.

[37]Kroll, *Kroll Increases U.S. Normalized Risk-Free Rate from 3.0% to 3.5%, but Spot 20-Year U.S. Treasury Yield Preferred When Higher* (Jun. 16, 2022).

**Table CCW-12**

**CAPM Results Summary**

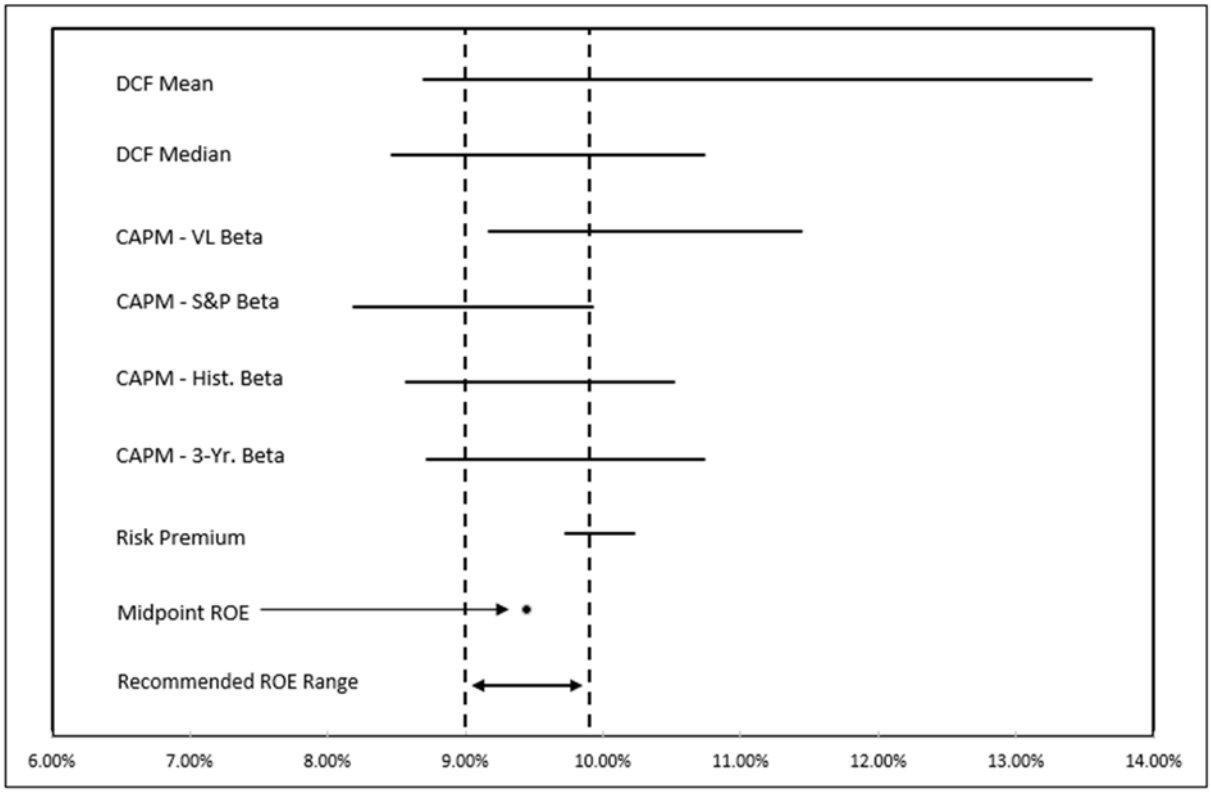
| Description | Current VL Beta | Historical VL Beta | Current S&P Beta | 3-Year Beta |
|---|---|---|---|---|
| Kroll Method | 9.17% | 8.57% | 8.19% | 8.72% |
| RP Method | 10.83% | 9.98% | 9.45% | 10.19% |
| FERC DCF Method | 11.44% | 10.51% | 9.92% | 10.74% |
| **Average** | **10.48%** | **9.69%** | **9.19%** | **9.88%** |

## K. Return on Equity Summary

**Q BASED ON THE RESULTS OF YOUR RETURN ON COMMON EQUITY ANALYSIS DESCRIBED ABOVE, WHAT RETURN ON COMMON EQUITY DO YOU RECOMMEND FOR THE COMPANY?**

A The results of my analyses are summarized in Figure CCW-5. In this figure, I present the various measures of central tendency for each of my analytical models.

**Figure CCW-5**




Based on my analyses of the various methodologies described above, I estimate the Company's current market ROE to be in the reasonable range of 9.00% to 9.90%. My recommended range accounts for the unsustainable growth rates assumed in the constant growth DCF model and the irrational assumption that *Value Line*'s current beta estimates are reflective of current investor expectations. In addition, my recommended range is captured by the range of results for each of the models and is consistent with measures of central tendency of those results. Based on my assessment of Consumers Energy's overall risk profile and the results of these analytical methods, I would recommend that this Commission authorize Consumers Energy a ROE of 9.45%, which is the midpoint of the range produced by these models.

**Q IN RECENT YEARS, THE COMMISSION HAS BEEN RELUCTANT TO REDUCE THE COMPANY'S AUTHORIZED ROE FROM ITS CURRENTLY AUTHORIZED LEVEL OF 9.9%. DO YOU HAVE ANY COMMENTS ON WHY THE COMMISSION SHOULD RECONSIDER THAT POSITION IN THIS CASE?**

A Yes, I do. As my colleague, Ms. Jessica York observes, in this proceeding, and in seven out of eight of Consumers Energy's most recent previous rate filings, the Company has reported a revenue sufficiency for its filed historical test year indicating recurring instances of Consumers Energy earning revenues in excess of its authorized amount due to the continuing use of a projected test year.

The Commission's statement in Case No. U-21585 that "with increased certainty of recovery of investments for the company and additional derisking, the ROE could be impacted in the future depending on the record evidence in the case" provides a clear framework for revisiting the Company's authorized return when the risk profile diminishes. Consumers Energy's persistent overearning, particularly through repeated revenue sufficiencies based on fully projected test years, squarely fits within this narrative and should prompt a reduction in the Company's authorized ROE of 9.90%.

**Q HOW DOES THE FACT THAT CONSUMERS ENERGY CONTINUALLY OVEREARNS ITS AUTHORIZED ROE FIT THE COMMISSION'S FRAMEWORK LAID OUT IN CASE NO. U-21585?**

A There are several components of Consumers Energy being a serial over-earner that fit the Commission's framework laid out in Case No. U-21585. First, there is evidence of increased certainty of cost recovery. Consumers Energy's ability to consistently overearn reflects a revenue model with little volatility or uncertainty. The continued

use of a fully projected test year, despite recurring overrecoveries, amplifies the certainty of cost recovery and suggests a mismatch between projected and actual risk.

Second, there is evidence of de-risking. A utility that overearns its authorized return in seven out of eight recent filings is evidently operating under conditions of reduced financial risk. This directly supports the Commission's view that de-risking, such as through mechanisms that provide stable cost recovery or overforecasted revenues, should be considered when evaluating whether an ROE reduction is warranted.

Third, the authorized ROE should reflect the actual risk. The Commission clearly stated that while past ROEs are a consideration, they are not fixed and should evolve with the utility's risk profile. If the utility is repeatedly earning above its authorized ROE due to regulatory mechanisms that insulate it from risk, then the authorized ROE should be reduced to reflect those mitigated risks.

Finally, the persistent revenue sufficiencies tied to projected test years suggest that Consumers Energy is systematically overprojecting its costs or underestimating its revenues. Requiring the use of a historical test year would more accurately reflect the utility's actual earnings and mitigate inflated revenue requirements. This would, in turn, expose the extent to which the utility's earnings are not only stable but systematically higher than what the Commission deemed just and reasonable.

Given the Commission's own reasoning that greater certainty of recovery and derisking could support a lower ROE, Consumers Energy's consistent overearning is strong evidence of reduced risk that justifies a downward adjustment. A reduction in

the authorized ROE would align regulatory returns with the utility's actual risk environment and help restore balance between ratepayer and shareholder interests.

# V. RESPONSE TO MS. BULKLEY

## A. Summary of Rebuttal to Ms. Bulkley

**Q WHAT RETURN ON COMMON EQUITY IS THE COMPANY PROPOSING FOR THIS PROCEEDING?**

A Ms. Bulkley recommends a range of 10.25% to 11.25% based on her market-based model results. The Company is requesting an ROE of 10.25% which represents the low-end of Ms. Bulkley's recommended range.[38]

**Q ARE MS. BULKLEY'S ROE ESTIMATES REASONABLE?**

A No. Ms. Bulkley's estimated ROE is overstated and should be rejected. Specifically, Ms. Bulkley's analyses produce excessive results for various reasons, including the following:

1. Her constant growth DCF results are based on unsustainably high growth rates;
2. Her CAPM is based on inflated market risk premiums; and
3. Her Risk Premium model is predicated on an excessive estimated risk premium.

**Q PLEASE SUMMARIZE MS. BULKLEY'S ROE ESTIMATES.**

A Ms. Bulkley's ROE estimates are summarized in Table CCW-13 below. With prudent and reasonable adjustments to Ms. Bulkley's DCF, CAPM, and Risk Premium return estimates, her studies show that my 9.45% recommended ROE for Consumers Energy is reasonable.

[38]Bulkley Direct at 10.

**TABLE CCW-13**

**Bulkley's Return on Equity Estimates**

| Description | Bulkley Results[1] | | |
|---|---|---|---|
| Constant Growth DCF (Mean) | Low | Mean | High |
| 30-Day Average | 8.59% | 9.87% | 11.30% |
| 90-Day Average | 8.79% | 10.06% | 11.50% |
| 180-Day Average | 8.95% | 10.23% | 11.66% |
| **DCF Average** | **8.78%** | **10.05%** | **11.49%** |
| Constant Growth DCF (Median) | Low | Median | High |
| 30-Day Average | 8.48% | 9.83% | 11.33% |
| 90-Day Average | 8.72% | 10.05% | 11.57% |
| 180-Day Average | 8.86% | 10.17% | 11.71% |
| **DCF Average** | **8.69%** | **10.02%** | **11.54%** |
| | 30-Year Treasury Bond Yield | | |
| CAPM DCF-Derived Results | Current Treasury | Near-Term Proj. Treasury | Long-Term Proj.Treasury |
| Value Line | 11.05% | 11.04% | 11.07% |
| Bloomberg | 10.15% | 10.13% | 10.20% |
| LT Average | 10.08% | 10.06% | 10.13% |
| **CAPM Average** | **10.43%** | **10.41%** | **10.47%** |
| ECAPM | **10.56% - 11.32%** | | |
| Risk Premium | | | |
| Current 30-Yr Treasury | 10.22% | | |
| Near-Term Projected 30-Yr Treasury | 10.19% | | |
| Long-Term Projected 30-Yr Treasury | 10.35% | | |
| Risk Premium Average | **10.25%** | | |
| **Recommended Range** | 10.25% - 11.25% | | |
| **Company Proposed ROE** | **10.25%** | | |

Sources: [1]Bulkley Direct Testimony, page 60.

I will discuss my concerns with each of her analytical methods and conclusions below.

## B. Ms. Bulkley's Constant Growth DCF

**Q PLEASE DESCRIBE MS. BULKLEY'S CONSTANT GROWTH DCF RETURN ESTIMATES.**

A Ms. Bulkley's constant growth DCF returns are developed on her Exhibit A-14 (AEB-1), Schedule D-5 page 4. Ms. Bulkley's constant growth DCF models are based on consensus growth rates published by *Yahoo! Finance and Zacks* and individual growth rate projections made by *Value Line*.

She relied on dividend yield calculations based on average stock prices over three different time periods: 30-day, 90-day and 180-day ending September 30, 2024. Ms. Bulkley's DCF analysis considers the low, mean, and high growth rates for each of her proxy companies. Her proxy group's low, mean, and high growth rates are 4.80%, 6.05%, and 7.46%, respectively.[39] Her average DCF results range from 8.78% to 11.49%. The average of her median DCF results range from 8.69% to 11.54%.

**Q ARE THE CONSTANT GROWTH DCF RESULTS PRODUCED BY MS. BULKLEY REASONABLE?**

A No. Ms. Bulkley's results are overstated. As discussed in my own DCF study, her consensus analysts' growth rates are substantially higher than the long-term sustainable growth rate of 4.14% as described above. Specifically, Ms. Bulkley's constant growth DCF model is based on growth rates of 4.80%, 6.05%, and 7.46%, respectively. These growth rates exceed projected GDP growth, meaning even her low-growth rate scenario produces potentially excessive results. As I discuss in greater detail above, growth rates that exceed the growth rate of GDP in the country

[39]Exhibit No. A-14 (AEB-1).

in which the utility provides goods and services cannot be sustained. Therefore, her DCF model results should be considered high-end return estimates. Given the fact that Ms. Bulkley's average and Maximum-Growth scenarios assume an average growth rate of 6.05% and 7.46%, which exceed the consensus long-term projected growth rate of the U.S. economy by 191 and 332 basis points, respectively, they should be given little weight. Because of the economic infirmities with her assumed proxy company growth rate that exceeds the expected growth of the US economy in perpetuity, Ms. Bulkley should have considered the results of a multi-stage DCF.

As shown above in Table CCW-13, the average of her Minimum-Growth and Average Growth rate constant growth DCF is approximately 9.4%. As shown on my Exhibit AB-13, the average and median multi-stage DCF ROEs for my proxy group using the 13-week average stock price are 8.71% and 8.46%. After considering the multi-stage model, a DCF-based ROE closer to 9.0% is reasonable.

## C. Ms. Bulkley's CAPM Studies

**Q PLEASE DESCRIBE MS. BULKLEY'S CAPM ANALYSIS.**

A As indicated above, the CAPM analysis is based upon the theory that the market required ROR for a security is equal to the risk-free rate, plus a risk premium associated with the specific security. The risk premium associated with the specific security is expressed mathematically as:

Bi x (Rm - Rf) where:

Bi = Beta - Measure of the risk for stock
Rm = Expected return for the market portfolio
Rf = Risk-free rate

**Q PLEASE DESCRIBE THE ISSUES YOU HAVE WITH MS. BULKLEY'S CAPM STUDY.**

A My primary concern with Ms. Bulkley's CAPM study is her sole reliance on a single DCF-derived expected market return ultimately used to estimate the market risk premiums inflates her results.

**Q PLEASE DESCRIBE MS. BULKLEY'S MARKET RISK PREMIUMS.**

A Ms. Bulkley derived her market risk premiums by conducting a DCF analysis for the market (S&P 500) and subtracting three estimates of the risk-free rate. Ms. Bulkley used three market risk premium estimates of 7.97%, 8.02%, and 7.74% based on a DCF market return of 12.04% less the current, near-term, and projected 30-year Treasury bond yields of 4.07%, 4.02%, and 4.30%, respectively.[40]

**Q WHAT ISSUES DO YOU HAVE WITH MS. BULKLEY'S DCF-DERIVED MARKET RISK PREMIUM ESTIMATES?**

A Ms. Bulkley's DCF-derived market risk premiums are based on a market return of approximately 12.04%, which consists of a weighted average growth rate component of 10.45% and weighted expected dividend yield of approximately 1.52%.[41] As discussed above with respect to my own DCF model, the DCF model requires a long-term sustainable growth rate. Ms. Bulkley's sustainable market growth rate of 10.45% is far too high to be a rational outlook for sustainable long-term market growth. This growth rate is nearly three times the growth rate of the U.S. GDP long-term growth outlook of 4.14%.

[40]Exhibit No. A-14 (AEB-1), Schedule D-5, page 6.
[41]*Id*. (12.04% = 1.52% x (1 + 0.5 x 10.45%) + 10.45%).

In fact, in the Chartered Financial Analyst ("CFA") curriculum textbooks, the CFA Institute notes as follows with regard to earnings growth rates for the companies within the composite indices (i.e., S&P 500):

> Earnings growth for the overall national economy can differ from the growth of earnings per share in a country's equity market composites. This is due to the presence of new businesses that are not yet included in the equity indices and are typically growing at a faster rate than the mature companies that make up the composites. **Thus, the earnings growth rate of companies making up the composites should be lower than the earnings growth rate for the overall economy.**[42]

Given the fact that Ms. Bulkley casts doubt on the DCF model and the optimistic long-term growth rates used to develop her DCF on the market, she should have supplemented her analysis with multiple approaches to estimating the market return, as I have done.

**Q DO YOU HAVE ANY OTHER COMMENTS CONCERNING MS. BULKLEY'S CAPM ANALYSIS?**

A Yes. I find it curious that Ms. Bulkley expresses how she has little faith in the DCF model as it applies to her proxy group,[43] yet it is the only method she relies on in estimating the expected return on the market. A more balanced approach would be to employ multiple methodologies as I have done. Ms. Bulkley's use of a single model to estimate the market return is biased and should be rejected. Finally, Ms. Bulkley's CAPM results are biased upward given her inappropriate inclusion of NiSource in her proxy group.

[42]CFA Program Curriculum, 2014 Level II Vol. 1, "Ethical and Professional Standards, Quantitative Methods, and Economics", Paul Kutasovic, Reading 15 – Economic Growth and the Investment Decision, p. 609, footnote 5 (Emphasis Added).

[43]Bulkley Direct at 7; 37-38.

## D. Ms. Bulkley's Empirical CAPM ("ECAPM") Studies

**Q PLEASE DESCRIBE MS. BULKLEY'S ECAPM ANALYSIS.**

A Ms. Bulkley relies on empirical tests of the traditional CAPM model to modify it in such a way to attempt to *correct* the original CAPM for some deficiencies inherent in the original model. Empirical tests show that the expected return line, or security market line, predicted by the CAPM are not as steep as the model would have us believe. In other words, the traditional CAPM understates the expected return for securities with betas less than 1, and overstates the expected return for securities with betas greater than 1. In order to correct for this empirical finding, Ms. Bulkley modifies the traditional CAPM model as follows:

$$R_i = R_f + 0.75 \times B_i \times (R_m - R_f) + 0.25 \times B_m \times (R_m - R_f)$$ where:

$R_i$ = Required return for stock i
$R_f$ = Risk-free rate
$R_m$ = Expected return for the market portfolio
$B_m$ = Beta of the market
$B_i$ = Beta - Measure of the risk for stock

**Q WHAT ISSUES DO YOU TAKE WITH MS. BULKLEY'S ECAPM ANALYSIS?**

A The biggest issue I have with Ms. Bulkley's ECAPM analysis is her use of an adjusted beta as published by *Value Line*. The impact of Ms. Bulkley's ECAPM adjustments increases her adjusted beta estimate range of 0.75-0.88 to a range of 0.82-0.91.[44] The weighting adjustments applied in the ECAPM are mathematically the same as adjusting beta since the inputs are all multiplicative as shown in the formula above. The result of both using adjusted betas and ECAPM is a flattening of the security market line.

[44] 75% x 0.75 + 25% x 1 = 0.82 and 75% x 0.88 + 25% x 1 = 0.91.

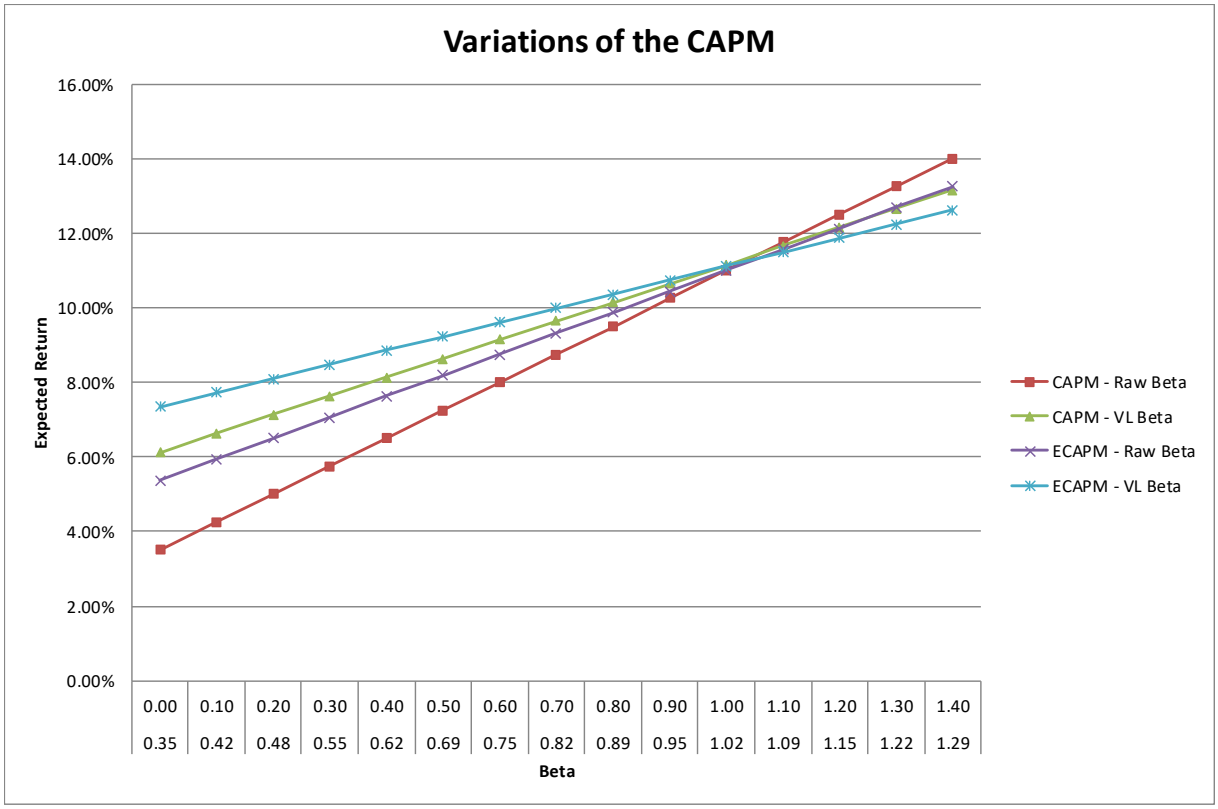
The end result of using adjusted betas in the ECAPM is an expected return line that has been flattened by two adjustments, meaning the vertical intercept has been raised twice and the security market line has been flattened twice: once through the adjustments *Value Line* made to the raw beta and again by weighting the risk-adjusted market risk premium as Ms. Bulkley has done.

In addition to the many adjustments employed by Ms. Bulkley, she further increases the intercept and flattens the security market line by using projected long-term Treasury yields.

**Q CAN YOU DEMONSTRATE THE EFFECT VARIOUS ADJUSTMENTS SUCH AS VALUE LINE BETAS AND THE ECAPM HAVE ON THE SECURITY MARKET LINE?**

A Yes. The ECAPM with adjusted betas has the effect of increasing CAPM return estimates for companies with betas less than 1 and decreasing the CAPM return estimates for companies with betas greater than 1. I have modeled the expected return line resulting from the application of the various forms of the CAPM/ECAPM below in Figure CCW-6.

**FIGURE CCW-6**




Along the horizontal axis in Figure CCW-6 above, I have provided the raw unadjusted beta (top row) and the corresponding adjusted *Value Line* beta (bottom row). As shown in Figure CCW-6 above, the CAPM using a *Value Line* beta compared to the CAPM using an unadjusted beta shows that the *Value Line* beta raises the intercept point and flattens the slope of the security market line. As shown in the figure above, the two variations with the most similar slope are the CAPM with the *Value Line* beta, and the ECAPM with a raw beta.

This evidence shows that the ECAPM adjustment has a very similar impact on the expected return line as a *Value Line* beta. Another observation that can be made from the figure above is the magnifying effect that the ECAPM using a *Value Line* beta has on raising the vertical intercept and flattening the slope relative to all other variations. There is simply no legitimate basis to use an adjusted beta within an

ECAPM because it unjustifiably alters the security market line and materially inflates a CAPM return for a company with a beta less than 1.

**Q IN YOUR EXPERIENCE, IS MS. BULKLEY'S PROPOSED USE OF AN ADJUSTED BETA IN AN ECAPM STUDY WIDELY ACCEPTED IN REGULATED UTILITY RATE PROCEEDINGS SUCH AS THIS?**

A No. In my experience, regulatory commissions generally disregard the use of the ECAPM, particularly when an adjusted beta is used in the model. For example, the Illinois Commerce Commission has stated the following regarding the ECAPM:

> The Commission cannot recall a proceeding in which it relied upon the ECAPM in establishing the cost of common equity for a utility. In the instant proceeding, the record supports a finding that use of adjusted betas in the ECAPM is inappropriate. As Staff witness Ms. Freetly explained, by using adjusted betas she already effectively transformed her Traditional CAPM into an ECAPM. Therefore, including an additional beta adjustment in the ECAPM model would result in inflated estimates of the samples' cost of common equity.[45]

Similarly, the California Public Utilities Commission has stated "We are not persuaded that ECAPM produces a result that should be considered. Electric utilities in general have low betas. Adjusting betas upward guarantees a higher ROE."[46]

Therefore, the Commission should reject Ms. Bulkley's ECAPM, which as described above is based on adjusted beta estimates.

## E. Ms. Bulkley's Bond Yield Risk Premium ("BYRP")

**Q PLEASE DESCRIBE MS. BULKLEY'S BYRP METHODOLOGY.**

A As shown on her Exhibit No. A-14 (AEB-1), Schedule D-5, pages 22-25, Ms. Bulkley constructs a risk premium ROE estimate based on the premise that equity risk

[45]Illinois-American Water Company, ICC Order Docket No. 11-0767, at page 109, September 19, 2012).

[46]https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M344/K961/344961040.PDF.

premiums are inversely related to interest rates. She estimates the average natural gas equity risk premiums of approximately 5.30% over the period January 1980 through September 2024. She performs a linear regression using the 30-year Treasury yield as the independent variable (x-axis) and the risk premium as the dependent variable (y-axis). This model produces a regression formula, which she applies by inputting the current, near-term, and long-term projected 30-year Treasury bond yields of 4.07%, 4.02%, and 4.30%, respectively. The resulting expected equity risk premiums based on these inputs are 6.15%, 6.17%, and 6.05%, respectively. She then adds these estimated risk premiums to their corresponding levels of interest rates to produce electric ROE estimates of 10.22%, 10.19%, and 10.35%, respectively.

**Q IS MS. BULKLEY'S BYRP METHODOLOGY REASONABLE?**

A No. As an initial matter, even though her analysis is predicated on the authorized ROEs for electric utilities as the starting point, the results exceed the highest ROE awarded to any electric utility this year. Notwithstanding that observation, my main concern with Ms. Bulkley's BYRP analysis is that her estimated equity risk premium is significantly overstated. For example, I incorporated the long-term average equity risk premium of 5.63% over long-term Treasury yields. This compares to the 2023 and 2024 equity risk premiums of 5.54%. In a report issued last year, Regulatory Research Associates (a division of S&P Global) discussed the equity risk premium, as measured by the authorized ROE spread over bond yields as follows:

> However, with the uptick in interest rates since 2020, the spread has begun to narrow, falling to around 550 basis points in 2023. With the myriad factors putting upward pressure on customer bills, <u>the spread</u>

may continue to narrow as regulators may become more reluctant to raise authorized returns.[47]

As indicated on Exhibit AB-15, the average Treasury yield in 2023 and 2024 was 4.09% and 4.41%, respectively. The average equity risk premium over Treasury yields over those two years were 5.51% and 5.30%, respectively. As discussed above, the most recent 13-week average 30-year Treasury yield is 4.22%. Ms. Bulkley assumed 30-year Treasury yields in the range of 4.02% to 4.30%. In order to be consistent with Ms. Bulkley's inverse relationship hypothesis, the equity risk premium should be consistent with the equity risk premiums in the range of 5.3% to 5.5% since interest rates assumed by Ms. Bulkley are with the interest rates realized over 2023 and 2024. However, Ms. Bulkley's estimated equity risk premiums range from 6.05% to 6.17%, representing an increase 54 to 87 basis points relative to the 2023 and 2024 equity risk premiums. Therefore, Ms. Bulkley's BYRP analysis should be given little weight.

**Q DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?**

A Yes, it does.

[47]RRA, Major energy rate case decisions in the US January-December 2023 Quarterly update on decided rate cases, February 6, 2024. (Emphasis Added).

## Qualifications of Christopher C. Walters

**Q PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.**

A Christopher C. Walters. My business address is 16690 Swingley Ridge Road, Suite 140, Chesterfield, MO 63017.

**Q PLEASE STATE YOUR OCCUPATION.**

A I am a consultant in the field of public utility regulation and a Principal with the firm of BAI, energy, economic and regulatory consultants.

**Q PLEASE STATE YOUR EDUCATIONAL BACKGROUND AND PROFESSIONAL EMPLOYMENT EXPERIENCE.**

A I received a Bachelor of Science Degree in Business Economics and Finance from Southern Illinois University Edwardsville. I have also received a Master of Business Administration Degree from Lindenwood University.

As a Principal at BAI, I perform detailed technical analyses and research to support regulatory projects including expert testimony covering various regulatory issues. Since my career at BAI began in 2011, I have held the positions of Analyst, Associate Consultant, Consultant, Senior Consultant, and Associate. Throughout my tenure, I have been involved with several regulated projects for electric, natural gas and water and wastewater utilities, as well as competitive procurement of electric power and gas supply. My regulatory project work includes estimating the cost of equity capital, capital structure evaluations, assessing financial integrity, merger and acquisition related issues, risk management related issues, depreciation rate studies, and other revenue requirement issues.

BAI was formed in April 1995. BAI and its predecessor firm have participated in more than 700 regulatory proceedings in 40 states and Canada.

BAI provides consulting services in the economic, technical, accounting, and financial aspects of public utility rates and in the acquisition of utility and energy services through RFPs and negotiations, in both regulated and unregulated markets. Our clients include large industrial and institutional customers, some utilities and, on occasion, state regulatory agencies. We also prepare special studies and reports, forecasts, surveys and siting studies, and present seminars on utility-related issues.

In general, we are engaged in energy and regulatory consulting, economic analysis and contract negotiation. In addition to our main office in St. Louis, the firm also has branch offices in Corpus Christi, Texas; Louisville, Kentucky and Phoenix, Arizona.

**Q HAVE YOU EVER TESTIFIED BEFORE A REGULATORY BODY?**

A Yes. I have sponsored testimony before state regulatory commissions including: Arizona, Arkansas, Colorado, Delaware, Florida, Georgia, Illinois, Iowa, Kansas, Kentucky, Louisiana, Maryland, Massachusetts, Michigan, Minnesota, Missouri, Montana, Nevada, New Mexico, North Carolina, Ohio, Oklahoma, Oregon, South Carolina, Texas, Utah, and Wyoming. In addition, I have also sponsored testimony before the City Council of New Orleans and an affidavit before the FERC.

**Q PLEASE DESCRIBE ANY PROFESSIONAL REGISTRATIONS OR ORGANIZATIONS TO WHICH YOU BELONG.**

A I earned the Chartered Financial Analyst (“CFA”) designation from the CFA Institute. The CFA charter was awarded after successfully completing three examinations

which covered the subject areas of financial accounting and reporting analysis, corporate finance, economics, fixed income and equity valuation, derivatives, alternative investments, risk management, and professional and ethical conduct. I am a member of the CFA Institute and the CFA Society of St. Louis.

MR. CAMPBELL: Also in lieu of cross-examination of certain Company and Staff witnesses and pursuant to stipulation or non-objection of the parties, at this time I'd move for admission of hearing Exhibits AB-24 through AB-28, which consist of certain discovery responses from Consumers Energy and Commission Staff.

JUDGE VARCHETTI: All right. Are there any objections to the admission of Exhibits AB-24 through AB-28?

I am hearing none, so these exhibits are admitted.

MR. CAMPBELL: Thank you, Your Honor. That's all for ABATE.

JUDGE VARCHETTI: Thank you.

Is there any other party who wishes to go next?

All right. Mr. Lussier, I see you are raising your hand. You can proceed, if you wish.

MR. LUSSIER: Yes, Your Honor. Thank you very much.

So on behalf of Michigan State University and Lansing Board of Water and Light, we have only one witness, Timothy S. Lyons. I would move to bind in his direct testimony, which consists of a cover sheet,

a table of contents, a list of exhibits, and 15 pages of questions and answers. I would move to admit the four exhibits that Mr. Lyons sponsored, along with his direct testimony, which there are four of them, which are marked LBWL-MSU-1 through 4.

And finally, Your Honor, I would move to bind in Mr. Lyons' rebuttal testimony, which consists of a cover page, a table of contents, and four pages of questions and answers.

JUDGE VARCHETTI: All right. Are there any objections to binding in the direct and rebuttal testimony of Mr. Lyons, or the four associated exhibits?

I am hearing none, so the testimony is bound into the record, and the exhibits are admitted.

MR. LUSSIER: Thank you, Your Honor.

(Direct and Rebuttal Testimony bound in)

**STATE OF MICHIGAN**
**BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION**

| | | |
|---|---|---|
| In the matter of the Application of CONSUMERS ENERGY COMPANY for authority to increase its rates for the distribution of natural gas and for other relief. | ) ) ) ) | Case No. U-21806 |

**DIRECT TESTIMONY OF**

**TIMOTHY S. LYONS**

**SCOTTMADDEN, INC.**

**SUBMITTED ON BEHALF OF**

Lansing Board of Water & Light and

Michigan State University

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**LIST OF EXHIBITS**

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LBWL/MSU-2 (TSL-2) Functionalization and Allocation of Other Distribution Plant
LBWL/MSU-3 (TSL-3) Proposed COSS Using Consumers Energy's Exhibits
LBWL/MSU-4 (TSL-4) Proposed Rate Design Using Consumers Energy's Exhibits

## I. INTRODUCTION

**Q. PLEASE STATE YOUR NAME, POSITION, AND BUSINESS ADDRESS.**

A. My name is Timothy S. Lyons. I am a Partner at ScottMadden, Inc. ("ScottMadden"). My business address is 3 Speen Street, Suite 150, Framingham, Massachusetts 01701.

**Q. ON WHOSE BEHALF ARE YOU SUBMITTING THIS TESTIMONY?**

A. I am submitting this testimony on behalf of the Lansing Board of Water & Light ("LBWL") and Michigan State University ("MSU") (together, "LBWL/MSU") before the Michigan Public Service Commission (the "Commission").

**Q. PLEASE DESCRIBE YOUR PROFESSIONAL EXPERIENCE.**

A. I have more than 30 years of experience in the energy industry. I started my career in 1985 at Boston Gas Company, eventually becoming Director of Rates and Revenue Analysis. In 1993, I moved to Providence Gas Company, eventually becoming Vice President of Marketing and Regulatory Affairs. Starting in 2001, I held several management consulting positions in the energy industry first at KEMA and then at Quantec, LLC. In 2005, I became Vice President of Sales and Marketing at Vermont Gas Systems, Inc. before joining Sussex Economic Advisors, LLC ("Sussex") in 2013. Sussex was acquired by ScottMadden in 2016.

**Q. WHAT IS YOUR EDUCATIONAL BACKGROUND?**

A. I hold a bachelor's degree from St. Anselm College, a master's degree in economics from The Pennsylvania State University, and a master's degree in business administration from Babson College.

**Q. HAVE YOU PREVIOUSLY SPONSORED TESTIMONY BEFORE THIS COMMISSION?**

A. Yes. I have previously sponsored testimony before more than 30 U.S. and Canadian regulatory agencies, including the Commission. A summary of my professional experience and education is included in Exhibit LBWL/MSU-1 (TSL-1).

## II. PURPOSE OF TESTIMONY

**Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?**

A. The purpose of my testimony is to present LBWL/MSU's findings and recommendations regarding Consumers Energy Company's ("Consumers Energy") application for authority to increase rates for the distribution of natural gas.

The testimony is organized into the following sections:

- Section III – Summary of Findings and Recommendations
- Section IV – Description of Rate XXLT Service and Current Rates
- Section V – Class Cost of Service Study Findings
- Section VI – Recommendations

Before beginning, I will provide a brief description of LBWL and MSU.

**Q. PLEASE PROVIDE A BRIEF DESCRIPTION OF LBWL.**

A. LBWL is a municipally owned public utility founded in 1885. LBWL is the largest municipal electric utility in Michigan.

LBWL owns and operates an electric system that generates, purchases, and distributes electricity to around 100,000 homes and businesses in the greater Lansing area.

LBWL is implementing a plan to achieve carbon neutrality by 2040 with a host of new renewable energy and storage projects.

LBWL commenced commercial operation of a new natural gas-fired power plant ("Delta Energy Park") in March 2022. The Delta Energy Park is located at the Erickson Power Station facility in Delta Township, Eaton County. The plant can generate 260 Megawatts of power. LBWL also operates the REO Town Cogeneration Plant ("REO") located in Lansing. REO generates steam for commercial, industrial, and a handful of residential customers as well as 100 Megawatts of power.

LBWL utilizes natural gas primarily for steam and electricity generation. LBWL currently receives transportation service from Consumers Energy under Rate Schedule Extra Extremely Large Transport ("Rate XXLT") since it uses more than 4,000,000 Mcf annually.[1]

**Q. PLEASE PROVIDE A BRIEF DESCRIPTION OF MSU.**

A. MSU is a public research university founded in 1855 and located in East Lansing, Michigan. MSU is one of the largest universities in the United States in terms of enrollment and alumni.

MSU owns and operates the T.B. Simon Power Plant that has provided cogenerated steam and electricity to the East Lansing campus for more than five decades. Steam is used to heat campus buildings in the winter and cool buildings in the summer.

[1] gas-rate-book.ashx

MSU is working toward climate neutrality by 2050. MSU's goal is to reduce Scope 1 and 2 greenhouse gas emissions by 50.00 percent by 2030 as measured from a 2010 baseline.[2] MSU recently invested $65.0 million to upgrade the T.B. Simon Power Plant, making it more efficient and flexible with the capability to reduce emissions and expenses without compromising reliability.[3]

MSU utilizes natural gas in its T.B. Simon Power Plant. MSU currently receives transportation service from Consumers Energy under Rate XXLT since it uses more than 4,000,000 Mcf annually.

## III. SUMMARY OF FINDINGS AND RECOMMENDATIONS

**Q. WHAT ARE YOUR FINDINGS REGARDING CONSUMERS ENERGY'S RATE PROPOSALS?**

A. LBWL/MSU's findings are summarized below.

First, LBWL/MSU finds that Version 2 of Consumers Energy's COSS study more accurately reflects Consumers Energy's cost of service than Version 1. Specifically, Version 2 reflects the following improvements: (a) removes Asset Retirement Costs (ARC) from calculation of other distribution plant because the costs are not included in the distribution plant revenue requirement; (b) separately allocates other distribution plant by FERC accounts 374 (Land & Land Rights), 375 (Structures and Improvements), 377 (Compressor Station Equipment), 378 (Measuring and Regulating Station Equipment),

[2] https://strategicplan.msu.edu/strategic-plan/stewardship-sustainability
[3] https://ipf.msu.edu/about/news/power-plant-upgrades-move-msu-closer-greenhouse-gas-reduction-goals

and 382 (Meter Installation) to reflect the FERC accounts serve different functions; and (c) separately allocates Customer Care Center (CCC) and Business Customer Care (BCC) expenses to better reflect resource utilization and cost causation.[4]

Second, LBWL/MSU finds that Version 2 does not accurately allocate other distribution plant to Rate XXLT. Version 2 misses a step because it does not first functionalize or apportion other distribution plant between High Pressure ("HP") mains and non-High Pressure ("non-HP") mains before allocating other distribution plant to each rate class. The consequence of not first functionalizing other distribution plant is that Rate XXLT is allocated a substantial portion of other distribution plant that is used to serve non-HP mains. Rate XXLT customers are not served from nor otherwise utilize non-HP mains and thus should not be allocated any other distribution plant that serves non-HP mains.

For example, Consumers Energy's analysis of measuring and regulator stations shows only 23 of the Company's 648 stations in FERC account 378 (Measuring and Regulating Station Equipment) are used to serve HP mains. Measuring and regulation stations represent 60.60 percent of other distribution plant.[5] The 23 stations serving HP mains represent only 9.90 percent of the Company's measuring and regulator station plant investment.[6] By comparison, the remaining 625 stations representing 91.10 percent of measuring and regulator station plant investment are used to serve non-HP mains. Rate XXLT customers are not served from and do not utilize non-HP mains. Therefore,

[4] Direct Testimony of Samuel M. Geller, pp. 6-11.
[5] FERC account 378 represents 70.44 percent of other distribution plant. Measuring and regulator stations represent 86.07 percent of FERC account 378.
[6] Exhibit No. A-57 (SMG-6), p. 1.

other distribution plant costs that serve non-HP mains should not be allocated to Rate XXLT customers that do not utilize non-HP mains.

While not included in Version 2 of the COSS study, Consumers Energy prepared a schedule that first functionalizes other distribution plant into HP and non-HP mains that can then be used to allocate other distribution plant to each rate class.[7] The functionalization is based on HP and non-HP mains investment.

LBWL-MSU believes Consumers Energy's schedule that first functionalizes other distribution plant into HP and non-HP mains should be used to allocate other distribution plant to each rate class in Version 2 of the COSS study because it more accurately reflects the cost of service to each rate class.

**Q. WHAT ARE YOUR RECOMMENDATIONS TO THE COMMISSION?**

A. LBWL/MSU recommends the Commission approve Version 2 of Consumers Energy's COSS study, modified to reflect Consumers Energy's schedule that first functionalizes other distribution plant into HP and non-HP mains and then allocates other distribution plant to each rate class, as shown in Figure 1 (below).

[7] See Consumers Energy workpaper WP-SMG-1-26.xlsx, tab WP24 HP_Non-HP Mains.

**Figure 1: Functionalization and Allocation of Other Distribution Plant**

| Other Distribution Plant | Dist. HP Average & Peak Allocator 105 | Dist. Non-HP Average & Peak Allocator 106 | Weighted Dist. HP Mains | Weighted Dist. Non-HP Mains | Weighted HP and Non HP Plant (Allocator 217) |
|---|---|---|---|---|---|
| | (a) | (b) | (c) | (d) | (e) |
| Functionalization Step | | | | | |
| HP vs. Non-HP Mains | 13.23% | 86.77% | | | |
| Allocation Step | | | | | |
| Residential | 0.5662 | 0.6445 | 0.0749 | 0.5592 | 0.6341 |
| Rate GS-1 | 0.1100 | 0.1192 | 0.0145 | 0.1034 | 0.1180 |
| Rate GS-2 | 0.1060 | 0.1143 | 0.0140 | 0.0992 | 0.1132 |
| Rate GS-3 | 0.0256 | 0.0250 | 0.0034 | 0.0217 | 0.0251 |
| Rate ST | 0.0505 | 0.0500 | 0.0067 | 0.0433 | 0.0500 |
| Rate LT | 0.0451 | 0.0343 | 0.0060 | 0.0297 | 0.0357 |
| Rate XLT | 0.0705 | 0.0128 | 0.0093 | 0.0111 | 0.0204 |
| Rate XXLT | 0.0260 | 0.0000 | 0.0034 | 0.0000 | 0.0034 |
| | | | 0.1323 | 0.8677 | 1.0000 |

The Figure shows other distribution plant is first functionalized into HP mains of 13.23 percent and non-HP mains of 87.66 percent based on HP and non-HP mains investment.

The Figure also shows other distribution plant is then allocated to each rate class based on a new allocator 217 that is the weighted average of two existing allocators: (1) HP mains allocator 105, which is applied to the portion of other distribution plant functionalized as HP mains, and (2) non-HP mains allocator 106, which is applied to the portion of other distribution plant functionalized to non-HP mains. Allocators 105 and 106 are weighted by the portion, respectively, of HP and non-HP mains investment. The approach to first functionalize and then allocate costs is well established and widely utilized in the utility industry.[8]

Allocator 217 represents a reasonable approach to first functionalize and then allocate other distribution plant for purposes of this proceeding.

[8] NARUC Gas Distribution Rate Design Manual, pp. 20-28.

Allocator 217 should be applied to Land & Land Rights (FERC 374), Structures and Improvements (FERC 375), Compressor Station Equipment (FERC 377), and Measuring and Regulating Station Equipment (FERC 378).

Allocator 108 should continue to be applied to Meters and Services (FERC 382), consistent with the Version 2.

**Q. WHAT IS THE IMPACT OF LBWL/MSU'S RECOMMENDATION?**

A. LBWL/MSU's recommendation to first functionalize and then allocate other distribution plant reduces Rate XXLT's proposed revenues from $10.1 million to $9.0 million, which represents a rate decrease of 11.00 percent, as shown on Exhibit LBWL/MSU-4 (TSL-4).

**Q. HAS LBWL/MSU UPDATED CONSUMERS ENERGY'S COST ALLOCATORS, COSS STUDY, AND RATE DESIGN WITH THE PROPOSED RECOMMENDATIONS?**

A. Yes. LBWL/MSU updated Consumers Energy's cost allocators, COSS study, and rate design workpapers to reflect LBWL/MSU's recommendation. The revised allocators, COSS study, and rate design are presented in Exhibits LBWL/MSU-2 (TSL-2), LBWL/MSU-3 (TSL-3), and LBWL/MSU-4 (TSL-4).

## IV. <u>TRANSPORTATION SERVICE AND CURRENT RATES</u>

**Q. PLEASE DESCRIBE CONSUMER ENERGY'S TRANSPORTATION SERVICE TO LBWL AND MSU UNDER THE CURRENT TARIFF.**

A. Consumers Energy provides transportation service to LBWL and MSU via its transmission and HP distribution mains. Consumers Energy receives gas from LBWL and MSU's third-party suppliers that is then delivered to LBWL and MSU's facilities via Consumers

Energy's transmission and HP distribution mains. LBWL and MSU are neither served from nor otherwise utilize Consumers Energy's non-HP distribution mains.

Transportation service is provided under Consumers Energy's Transportation Service Tariff. The Tariff consists of four service categories: Small Transportation ("Rate ST"), Large Transportation ("Rate LT"), Extremely Large Transportation ("Rate XLT"), and Rate XXLT.

LBWL and MSU take service under Rate XXLT since their annual usage exceeds 4,000,000 Mcf.

**Q. PLEASE DESCRIBE THE CURRENT RATE XXLT CHARGES.**

A. Presently, Rate XXLT charges consist of a Customer Charge, a Remote Metering Charge, and a Distribution Charge.[9] The Customer and Remote Metering charges are assessed monthly per meter. The Distribution charges are assessed on a per Mcf usage.

Consumers Energy provides a load balancing service for transportation customers that reconciles differences between gas receipts (supplies delivered to Consumers Energy's system) and gas deliveries (customer usage recorded at the meter), adjusted for system losses. The load balancing service provides a Transportation Charge Adjustment credit or charge on a per Mcf basis depending on the Authorized Tolerance Level ("ATL") selected by the customer. The Transportation Charge Adjustment is based on the cost of Consumers Energy's storage facilities.

[9] Exhibit A-16 (SAS-4), Schedule F-3, page 10 of 11.

Presently, Rate XXLT service is offered at 4.0% ATL. A Transportation Charge Adjustment credit is available to Rate XXLT at 2.0% ATL.[10]

**Q. WHAT ARE CONSUMER ENERGY'S PROPOSED CHANGES IN RATE XXLT CHARGES?**

A. Consumers Energy proposes the following changes to Rate XXLT charges: (1) decrease in the monthly customer charge from $43,618.55 per meter to $41,396.85 per meter; (2) no change in the remote metering charge of $70.00; and (3) increase in the distribution rate from $0.5177 per Mcf to $0.5278 per Mcf.[11]

## V. CLASS COST OF SERVICE STUDY

**Q. WHAT IS CONSUMERS ENERGY'S PROPOSAL RELATED TO THE COSS STUDY?**

A. Consumers Energy filed two COSS studies. The first COSS study (Version 1) employs methodologies previously adopted by the Commission in Case No. U-20650. The second COSS study (Version 2) reflects the following improvements to Version 1: (a) removes Asset Retirement Costs (ARC) from calculation of other distribution plant because the costs are not included in the distribution plant revenue requirement; (b) separately allocates other distribution plant by FERC accounts 374 (Land & Land Rights), 375 (Structures and Improvements), 377 (Compressor Station Equipment), 378 (Measuring and Regulating Station Equipment), and 382 (Meter Installation) to reflect the FERC accounts serve

[10] *Id.*
[11] *Id.*

different functions; and (c) separately allocates Customer Care Center (CCC) and Business Customer Care (BCC) costs to better reflect resource utilization and cost causation.[12]

**Q. WHICH VERSION WAS USED TO ESTABLISH CONSUMERS ENERGY'S PROPOSED RATE DESIGN?**

A. Version 2 was used to establish the proposed rate design. Consumers Energy states, "The Company…recommends adoption of COSS Version 2 for setting rates in this case."[13]

**Q. WHAT IS THE PURPOSE OF A COSS STUDY?**

A. A COSS study is used to allocate a utility's overall cost of service to each rate class in a manner that reflects its underlying cost of service. A COSS study identifies the relationship between the service requirements for each rate class and their respective cost drivers. The approach is well established and widely accepted in the utility industry.[14]

**Q. WHAT WAS CONSUMERS ENERGY'S APPROACH IN DEVELOPING THE COSS STUDY?**

A. Consumers Energy's developed the COSS study utilizing a three-step process. First, costs were functionalized or assigned into functional categories, largely related to storage, transmission, and distribution. Next, functionalized costs were classified according to their cost drivers. There are three primary cost drivers: (1) demand, representing costs that vary with peak demand; (2) customer, representing costs that vary with changes in the number

[12] Direct Testimony of Samuel M. Geller, pp. 5-11.
[13] *Id.* at 3.
[14] *See* "Principles of Public Utility Rates" by James C. Bonbright, 2nd Edition.

of customers; and (3) energy, representing costs that vary with changes in usage. Finally, classified costs were allocated to each rate class using a variety of factors that correlate to the identified cost drivers.[15]

**Q. DOES LBWL-MSU SUPPORT THE IMPROVEMENTS TO VERSION 2?**

A. Yes. LBWL-MSU supports the improvements to Version 2 because they more accurately reflect Consumers Energy's cost of service to each rate class than Version 1.

**Q. DOES LBWL/MSU HAVE RECOMMENDED CHANGES TO VERSION 2?**

A. Yes. LBWL/MSU recommends Version 2 be revised to first functionalize other distribution plant into HP and non-HP mains prior to allocation to each rate class.

**Q. WHAT CATEGORIES COMPRISE OTHER DISTRIBUTION PLANT?**

A. Other distribution plant consists of five categories, as shown in Figure 2 (below).

**Figure 2: Other Distribution Plant Categories[16]**

| Other Distribution Plant | | ($000) | % |
|---|---|---|---|
| Fee Land & Easements (374) | $ | 33,181 | 6.58% |
| Structures and Improvements (375) | | 69,188 | 13.71% |
| Compressor Station Equipment (377) | | 11,885 | 2.36% |
| M&R General (378) | | 355,404 | 70.44% |
| Meter Installations (382) | | 34,919 | 6.92% |
| Total | $ | 504,577 | 100% |

[15] Direct Testimony of Samuel M. Geller, pp. 4-5.
[16] See Exhibit A-16 (SMG-2), Schedule F-1.1, p. 3.

The Figure shows FERC account 378 (Measurement & Regulating Station Equipment) is the largest category of other distribution plant, representing more than 70.00 percent of other distribution plant.

**Q. HOW DOES CONSUMERS ENERGY ALLOCATE OTHER DISTRIBUTION PLANT?**

A. In Version 2 of the COSS study, Consumers Energy allocates FERC accounts 374 (Land & Land Rights), 375 (Structures and Improvements), 377 (Compressor Station Equipment), 378 (Measuring and Regulating Station Equipment) based on the transmission mains demands (allocator 104), and 382 (Meter Installation) based on weighted customers (allocator 108).

**Q. DOES LBWL/MSU HAVE CONCERNS WITH CONSUMERS ENERGY'S ALLOCATION OF OTHER DISTRIBUTION PLANT?**

A. Yes. First, LBWL/MSU agrees with Consumers Energy's allocation of meter installation plant based on weighted customers (allocator 108). The allocator appropriately reflects how costs are incurred to serve each class.

However, LBWL/MSU opposes Consumers Energy's allocation of the other categories of other distribution plant. Specifically, Consumers Energy's COSS study does not first functionalize other distribution plant into HP and non-HP mains and then allocate other distribution plant to each rate class.

Consequently, Rate XXLT is allocated a portion of non-HP mains. Rate XXLT customers are not served from nor otherwise utilize non-HP mains and therefore should not be allocated other distribution plant related to non-HP mains.

For example, Consumers Energy's detailed analysis of measuring and regulator stations shows only 23 of the Company's 648 stations in FERC account 378 (Measuring and Regulating Station Equipment) are used to serve the HP distribution system. Measuring and regulation stations represent 60.10 percent of other distribution plant. The 23 stations serving HP mains represent only 9.90 percent of Consumers Energy's measuring and regulator station plant investment. The remaining 625 stations representing 91.10 percent of other distribution plant investment are used to serve non-HP mains. Rate XXLT customers do not take service from nor otherwise utilize non-HP mains and thus should not be allocated other distribution plant related to non-HP mains.

**Q. HAS CONSUMERS ENERGY PREPARED A SCHEDULE THAT FIRST FUNCTIONALIZES AND THEN ALLOCATES OTHER DISTRIBUTION PLANT?**

A. Yes. While not included in Version 2 of its COSS study, Consumers Energy prepared a schedule that first functionalizes other distribution plant into HP and non-HP mains and then allocates other distribution plant to each rate class.[17] The schedule represents a reasonable approach to functionalization and allocation of other distribution plant.

The schedule shows other distribution plant is first functionalized into HP mains of 13.23 percent and non-HP mains of 87.66 percent based on plant records.

The schedule also shows other distribution plant is allocated to each rate class based on a new allocator 217 that is the weighted average of two existing allocators: (1) HP mains allocator 105, which is applied to the portion of other distribution plant functionalized as

[17] See Consumers Energy workpaper WP-SMG-1-26.xlsx, tab WP24 HP_Non-HP Mains.

HP mains, and (2) non-HP mains allocator 106, which is applied to the portion of other distribution plant functionalized to non-HP mains. The approach to first functionalize and then allocate costs is well established and widely accepted in the utility industry.[18]

LBWL/MSU believes allocator 217 represents a reasonable approach to first functionalize and then allocate other distribution plant for purposes of this proceeding.

**Q. WHAT IS THE IMPACT OF LBWL/MSU'S RECOMMENDATIONS?**

A. The impact of LBWL/MSU's recommendations reduces Rate XXLT's proposed revenues from $10.1 million to $9.0 million, which represents a rate decrease of 11.00 percent, as shown on Exhibit LBWL/MSU-4 (TSL-4).

## VI. RECOMMENDATIONS

**Q. WHAT ARE YOUR RECOMMENDATIONS TO THE COMMISSION?**

A. LBWL/MSU recommends the Commission approved Version 2 of Consumers Energy's COSS study, modified to reflect Consumers Energy's schedule that first functionalizes other distribution plant into HP and non-HP mains and then allocates other distribution plant to each rate class, as shown in Figure 1 (above).

**Q. DOES THIS CONCLUDE YOUR TESTIMONY?**

A. Yes. It does.

[18] NARUC Gas Distribution Rate Design Manual, pp. 20-28.

**STATE OF MICHIGAN**
**BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION**

| | | |
|---|---|---|
| In the matter of the Application of CONSUMERS ENERGY COMPANY for authority to increase its rates for the distribution of natural gas and for other relief. | ) ) ) ) | Case No. U-21806 |

# REBUTTAL TESTIMONY OF

**TIMOTHY S. LYONS**

**SCOTTMADDEN, INC.**

**SUBMITTED ON BEHALF OF**

**LANSING BOARD OF WATER & LIGHT AND**

**MICHIGAN STATE UNIVERSITY**

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## I. INTRODUCTION

**Q. PLEASE STATE YOUR NAME, POSITION, AND BUSINESS ADDRESS.**

A. My name is Timothy S. Lyons. I am a Partner at ScottMadden, Inc. ("ScottMadden"). My business address is 1 Speen Street, Suite 150, Framingham, Massachusetts 01701.

**Q. ARE YOU THE SAME TIMOTHY S. LYONS WHO FILED DIRECT TESTIMONY IN THIS PROCEEDING?**

A. Yes.

**Q. ON WHOSE BEHALF ARE YOU SUBMITTING THIS TESTIMONY?**

A. I am submitting this testimony on behalf of the Lansing Board of Water & Light ("LBWL") and Michigan State University ("MSU") (together, "LBWL/MSU") before the Michigan Public Service Commission (the "Commission").

**Q. WHAT IS THE PURPOSE OF YOUR REBUTTAL TESTIMONY?**

A. The purpose of my rebuttal testimony ("Rebuttal Testimony") is to address recommendations by Nicholas M. Revere on behalf of the Michigan Public Service Commission ("Staff") regarding the Consumers Energy's class cost-of-service study ("COSS") as well as recommendations by Kevin S. Krause on behalf of Staff regarding Consumers Energy's COSS.

## II. SUMMARY OF RECOMMENDATIONS

**Q. WHAT IS STAFF WITNESS REVERE'S RECOMMENDATION?**

A. Staff witness Revere's recommendation regarding Consumers Energy's COSS is summarized below:

- Allocate FERC Account 378 based on a composite allocator that reflects the categories of costs included in FERC Account 378.[1]

**Q. WHAT IS STAFF WITNESS KRAUSE'S RECOMMENDATION?**

A. Staff witness Krause's recommendation regarding Consumers Energy's COSS is summarized below:

- Allocate uncollectible expense based on revenues.[2]

## III. RESPONSE TO STAFF WITNESS REVERE'S RECOMMENDATION

**Q. DOES LBWL/MSU AGREE WITH STAFF WITNESS REVERE'S RECOMMENDATION TO ALLOCATE FERC ACCOUNT 378 BASED ON A COMPOSITE ALLOCATOR?**

A. Yes. LBWL/MSU agrees with Staff witness Revere that the proposed composite allocator best reflects how costs in FERC Account 378 should be allocated based on information provided by Consumers Energy about which costs are associated with each pressure level. As Staff witness Revere states,

> "Similar to how allocation is done for distribution mains based on pressure level and electric distribution costs based on voltage level, only allocating the costs associated with a given pressure level based on determinants served at that pressure level best reflects the cost causative relationship."[3]

[1] Direct Testimony of Nicholas M. Revere, pp. 6-9
[2] Direct Testimony of Kevin S. Krause, pp. 5-7
[3] Direct Testimony of Nicholas M. Revere, p. 8

The composite allocator is based on weighting the cost differences between measuring and regulating stations serving different pressure levels. The approach better reflects cost-causation.

## IV. RESPONSE TO STAFF WITNESS KRAUSE'S RECOMMENDATION

**Q. DOES LBWL/MSU AGREE WITH STAFF WITNESS KRAUSE'S RECOMMENDATION TO ALLOCATE UNCOLLECTIBLE EXPENSE BASED ON REVENUES?**

A. No. LBWL/MSU believes that Consumers Energy's method of allocating uncollectible expense to each rate class based on three years of historic net write offs should be accepted.

Consumer Energy's method better reflects the underlying cost of service to each rate class; that is, Consumers Energy's method directly assigns uncollectible expense to the rate class that caused the costs.

LBWL/MSU agrees with Staff witness Krause's statement on page 6 that the reasons for which a customer's account becomes uncollectible have only to do with that customer's unique circumstance and not those of any other customers in the rate class. However, the statement overlooks the premise that Consumers Energy's class cost of service and rates are based on the service requirements and cost of service of an entire rate class and not an individual customer or group of customers; otherwise, Consumers Energy would develop its class cost of service and rates based on the unique demand and cost characteristics of an individual customer or groups of customers rather than an entire rate class.

Consequently, it is appropriate on the basis of cost-causation to allocate uncollectible expense to each rate class based on their three years of historic net write offs.

## V. CONCLUSION

**Q. DOES THIS CONCLUDE YOUR TESTIMONY?**

A. Yes. It does.

JUDGE VARCHETTI: All right. That leaves just a few parties left. It looks like we have CUB and MEC and Sierra Club and Staff.

So, Mr. Bzdok, it looks like you're raising your hand. You can proceed, if you wish.

MR. BZDOK: Thank you, Your Honor.

Your Honor, at this time, on behalf of the Michigan Environmental Council and Sierra Club, I would move to bind into the record the direct testimony of Alice Napoleon, which consists of a cover page, tables, and 38 questions -- pages of questions and answers. Excuse me. And I would move to bind into the -- and to admit into evidence Exhibits MEC-1 through MEC-13.

JUDGE VARCHETTI: All right. Are there any objections to binding in the direct testimony of Ms. Napoleon or the associated exhibits?

I am hearing none, so the testimony is bound into the record and the exhibits are admitted.

MR. BZDOK: Thank you, Your Honor.

(Direct Testimony bound in)

**STATE OF MICHIGAN**

**MICHIGAN PUBLIC SERVICE COMMISSION**

| | |
|---|---|
| In the matter of the Application of **CONSUMERS ENERGY COMPANY** for authority to increase its rates for the distribution of natural gas and for other relief. | Case No. U-21806 |

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# DIRECT TESTIMONY OF

# ALICE NAPOLEON

# ON BEHALF OF

# MICHIGAN ENVIRONMENTAL COUNCIL AND SIERRA CLUB

**April 23, 2025**

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## I. INTRODUCTION AND PURPOSE OF TESTIMONY

**Q Please state your name and occupation.**

A My name is Alice Napoleon. I am a Principal Associate at Synapse Energy Economics, Inc. ("Synapse Energy Economics") located at 485 Massachusetts Avenue, Suite 3, Cambridge, MA 02139.

**Q Please describe Synapse Energy Economics.**

A Synapse Energy Economics is a research and consulting firm specializing in electricity and gas industry regulation, planning, and analysis. Our work covers a range of issues, including economic and technical assessments of demand-side and supply-side energy resources, energy efficiency policies and programs, integrated resource planning, electricity market modeling and assessment, renewable resource technologies and policies, and climate change strategies. Synapse works for a wide range of clients, including state attorneys general, offices of consumer advocates, trade associations, public utility commissions, environmental advocates, the U.S. Environmental Protection Agency, U.S. Department of Energy, U.S. Department of Justice, the Federal Trade Commission, and the National Association of Regulatory Utility Commissioners. Synapse's staff includes over 35 professionals with extensive experience in the electricity and gas industries.

**Q Please summarize your work experience and educational background.**

A Since joining Synapse in 2005, I have provided economic and policy analysis of electric and gas systems and emissions regulations on behalf of a diverse set of

clients throughout the United States and in Canada. I have co-authored several reports and comments on the role of energy efficiency in New York State in meeting its Reforming the Energy Vision ("REV") objectives, as well as two white papers on natural gas regulatory reforms needed if New York is to meet its decarbonization targets. I have also provided policy analysis and technical support on issues related to the future of natural gas utilities in many other states, including Hawaii, Maryland, Rhode Island, Colorado, Massachusetts, Nevada, and California.

I have provided expert advice on demand-side management programs in numerous states and Canadian provinces regarding a range of issues including incentive-setting methodologies, cost-benefit analysis, avoided costs, load forecasting, and locational demand-side management. I also co-authored a manual for regulators on designing performance incentive mechanisms for utilities, which has been highly utilized by many states.

Before joining Synapse, I worked at Resource Insight, Inc., where I supported investigations of electric, gas, steam, and water resource issues, primarily in the context of reviews by state utility regulatory commissions.

I hold a Master's in Public Administration from the University of Massachusetts at Amherst and a Bachelor's in Economics from Rutgers University. My resume is attached as Exhibit MEC-1.

**Q On whose behalf are you testifying in this case?**

A I am testifying on behalf of Michigan Environmental Council and Sierra Club.

**Q Have you previously testified before the Michigan Public Service Commission ("the Commission")?**

A Yes. I submitted testimony on behalf of Michigan Environmental Council, Natural Resources Defense Council, Sierra Club, and Citizens Utility Board of Michigan in the rate case for DTE Gas Company, U- 21291.

**Q What is the purpose of your testimony?**

A The purpose of my testimony is to review and critique Consumers Energy's ("Consumers" or the "Company") demand-side management investments in light of the energy transition, the Company's allocation of costs to new customers for new attachments, and its assumptions and methodology for its new connections forecast.

**Q Are you sponsoring any exhibits in this proceeding?**

A Yes, I am sponsoring the following exhibits:

- Exhibit MEC-1, Resume of A. Napoleon.
- Exhibit MEC-2, Discovery Response MNSC-CE-0709.
- Exhibit MEC-3, Discovery Response MNSC-CE-0039.
- Exhibit MEC-4, Discovery Response MNSC-CE-0714.
- Exhibit MEC-5, Discovery Response attachment MNSC-CE-0599_Warriner_ATT_1.
- Exhibit MEC-6, Discovery Response MNSC-CE-0595.
- Exhibit MEC-7, Discovery Response MNSC-CE-0024 and attachment 1.
- Exhibit MEC-8, Discovery Response MNSC-CE-0026 (partial – Warriner).

- Exhibit MEC-9, Discovery Response MNSC-CE-0031.
- Exhibit MEC-10, Discovery Response MNSC-CE-0018 (partial – Dreisig).
- Exhibit MEC-11, Discovery Response MNSC-CE-20 and Warriner ATT 4.
- Exhibit MEC-12, Discovery Response MNSC-CE-0585.
- Exhibit MEC-13, Part III Attachment 028, HSTART.

**Q Are there any other witnesses testifying on behalf of MEC, Sierra Club, and CUB?**

A Yes. Please refer to Witness Sol deLeon's testimony examining Consumers' handling of the energy transition, major infrastructure replacement programs, and handling of risk.

## II. FINDINGS AND RECOMMENDATIONS

**Q Please summarize your primary conclusions.**

A My findings include the following:

- The continued availability of incentives for gas appliances in the Energy Waste Reduction ("EWR") programs is inconsistent with Michigan's clean energy targets because they encourage customers to lock themselves into many years of gas use when more efficient electrification options are available.
- The Company's line extension policies incentivize new customer connections by subsidizing much of the cost to connect. There is a risk that these costs will be unduly borne by existing customers.

- The Company's new connection forecasting is flawed, assuming growth rates that are inconsistent with historical data and do not consider improving equipment efficiencies and market developments that favor heat pumps. A more reasonable assumption is that the number of new connections will not grow.

**Q Please summarize your recommendations.**

A Based on my findings, I offer the following recommendations:

- The Commission should require the Company to eliminate EWR incentives for gas-burning equipment. The next EWR plan should fund only electrification and building envelope measures using gas ratepayer funds in order to align EWR programs with the state's climate targets.
- The Commission should order the Company to reduce the allowance for new customer line extension costs to no more than 50 percent of total costs; this will better protect ratepayers from the risk that new customer connections may not produce the revenue forecasted by the Company, reduce incentives to expand the gas system, and better align Consumers' new customers' Contributions in Aid of Construction (CIAC) policies with Michigan's emission reduction targets. Further, the Commission should order Consumers to reduce its projected test year capital expenditures (2026) for New Business accordingly, as described in this testimony.
- The Commission should order the Company to set the growth rate in new connections to zero and reduce its capital expenditures for the same line item mentioned in the previous bullet, New Business, commensurately, as

described herein. Also, the Commission should require the Company to explain and document the relationship of the new connections forecast to the load forecast.

## III. DEMAND-SIDE INVESTMENTS ARE MISALIGNED WITH DECARBONIZATION OBJECTIVES

**Q Please describe the Company's Natural Gas Delivery Plan.**

A The Natural Gas Delivery Plan (NGDP) provides a 10-year outlook on infrastructure investments, natural gas supply and demand, and operational needs, as well as a financial summary of planned capital expenditure and operations and maintenance expenses through 2034. The plan centers around the Company's four key objectives, which are to provide service that is safe, reliable, affordable, and clean.[1] The NGDP includes the Company's discussion of its emission reduction targets and potential pathways toward decarbonization. In Appendix C of the NGDP, the Company provides some discussion of the findings from a state-wide decarbonization pathways analysis that it uses to inform which decarbonization strategies to pursue.

**Q Describe the Company's emission reduction targets.**

A The Company has a goal to reach net-zero methane emissions from Scope 1 sources by 2030, where Scope 1 emissions are defined as "emissions produced in the process of generating and supplying energy for customers, such as carbon emissions from burning methane or fugitive methane emissions from our natural

[1] Exhibit A-42, Natural Gas Delivery Plan (NGDP), page 15.

gas delivery system."[2,3] The Company intends to reduce 80 percent of its Scope 1 methane emissions by 2030 primarily through the replacement of leak-prone mains and services.[4] Investments to replace leak-prone pipe are discussed in the testimony of Dr. deLeon.

The Company also has the goal of reducing Scope 3 carbon emissions 20 percent by 2030 and to reach net-zero carbon emissions by 2050, where Scope 3 emissions are defined as "emissions traced to natural gas we purchase and activities by customers and suppliers, primarily from end uses like burning natural gas to heat homes and businesses."[5] The Company discusses numerous possible strategies for achieving Scope 3 emission reductions, which are loosely informed by the state-wide decarbonization pathways analysis. Consumers acknowledges the findings of the decarbonization pathways analysis and generally agrees with the need to

[2] NGDP, page 78.

[3] Data on Consumers' Scope 1, 2, and 3 emissions from its electric and gas operations combined are available in its 2024 Energy Sustainability Report, provided as Attachment 1 to Witness Dreisig's testimony. The following table is excerpted from this report.

| Electric & Gas Scope 1, 2 and 3 Greenhouse Gas Emissions | | | | |
|---|---|---|---|---|
| Carbon Dioxide Equivalent (CO2e) | 2005 | 2021 | 2022 | 2023 |
| Scope 1 $CO_2e$ emissions (MT) | N/A | 14,292,256 | 14,307,906 | 12,482,384 |
| Scope 2 $CO_2e$ market-based emissions (MT) | N/A | 62,753 | 61,195 | 52,960 |
| Scope 2 $CO_2e$ location-based emissions (MT) | N/A | 59,802 | 63,102 | 53,601 |
| Scope 3 $CO_2e$ emissions (MT) | N/A | 16,881,600 | 23,832,385 | 22,652,002 |

Most of the Scope 1 emissions are likely from electric operations, while most of the Scope 3 emissions are likely associated with Consumers' customers gas consumption. As shown in the table above, Scope 3 emissions are larger than Scope 1 emissions in all years, and they are substantially larger than Scope 1 emissions in 2022 and 2023 after Consumers completed a review of Scope 3 emissions to improve comprehensiveness.

[4] NGDP, page 78.

[5] NGDP, page 78.

reduce emissions, but the Company does not reflect the findings from the decarbonization analysis in its investment plan.

On the demand side, these include the EWR programs as well as potentially electrification. Consumers also lists supply-focused options including renewable natural gas ("RNG"), hydrogen, and synthetic fuels, as well as other strategies such as carbon offsets and carbon capture and sequestration.[6] The only decarbonization strategies the Company is actually pursuing at present are EWR programming and a voluntary RNG program offered through the MI Clean Air Program;[7] the costs of the voluntary program are not being recovered through base rates.[8]

**Q Please describe the decarbonization pathways analysis.**

A The NGDP discusses findings from a state-wide decarbonization analysis. This study analyzed five scenarios that met projected demand and achieved emission reductions with different combinations of resources.

**Q How did the decarbonization pathways analysis inform the Company's planning and decisions?**

A Based on the decarbonization analysis, the Company concludes that continued use of the gas transmission and distribution system alongside carbon capture is the

[6] NGDP, page 79-83.

[7] Ex MEC-2, Discovery Response MNSC-CE-0709.

[8] As discussed in my testimony in the DTE rate case (U-21291), voluntary RNG programs may not be effective means of reducing GHG emissions. As such, they are problematic even if they are not included in rate base because participants may feel that their decisions to consume more gas, or to remain on gas, are environmentally friendly choices. In this way, a customer-facing RNG program could work against the state's efforts to reduce GHG emissions.

most cost-effective solution to achieving decarbonization.[9] The analysis finds that a 'balanced scenario' with hybrid electric heating and gas backups mitigates electric winter peaks in the future, saving $20–$25 billion dollars compared to a scenario with full electrification.[10]

Appendix C to the NGDP recommends a scenario that features hybrid electric and gas space heating as a prominent strategy in the balanced scenario;[11] however, the Company has stated that it "does not have current plans to deploy or support hybrid heating through 2030 and 2050." [12] The only electrification measure the Company has indicated it might investigate is networked geothermal.[13] The pathways analysis also finds that RNG will play a primary role in decarbonization under the balanced scenario. In the NGDP, the Company states that RNG will be a "fundamental technology" for reducing emissions in a cost-effective way because it does not require making any incremental investments to the gas system.[14]

**Q Why did the study find that full electrification is more expensive?**

A It is not clear. While I reviewed the pathways analysis, there is an insufficient level of detail on assumptions and methodology to explain this conclusion. Consumers did not provide detailed findings and assumptions from the decarbonization study

[9] NGDP, page 91.

[10] NGDP, page 91.

[11] NGDP, page 91.

[12] Ex MEC-3, Discovery Response MNSC-CE-0039.

[13] Ex MEC-4, Discovery Response MNSC-CE-0714.

[14] NGDP, page 91.

because it was conducted by a third-party consultant.[15] However, the Company conveyed that the balanced scenario was identified as the optimal decarbonization pathway because it (1) has the lowest cost for achieving decarbonization targets (from an economy-wide perspective), (2) has the least impact to existing electric infrastructure, (3) poses less risk associated with hydrogen blending than other scenarios, and (4) leverages carbon capture. Thus, the study claims, the balanced scenario would avoid "the build out of nuclear energy as load increases" in the high electrification pathway.[16]

**Q Do you find this study to be persuasive?**

A No. As described in the attachment to Dr. deLeon's testimony, numerous other states have conducted pathways studies that come to vastly different conclusions about the ability of strategies that rely on hybrid electric and gas space heating to meet decarbonization goals. These include, but are not limited to, Massachusetts, New York, and Maryland. I do not know the specific reason(s) why the Michigan study identified the balanced scenario, which relies on hybrid electric and gas space heating, as the optimal decarbonization pathway; however, I expect that the study inappropriately assumed high levels of pipe replacement in all scenarios, consistent with *status quo* operations, but only electric system build-out in the high electrification scenario. Doing so would bias the study by inappropriately attributing high electric system build-out costs to the high electrification scenario

[15] Discovery Response MNSC-CE-0038.

[16] Discovery Response MNSC-CE-0707.

while not giving this pathway credit for pipe replacement that targeted electrification could avoid.

Further, nowhere does the decarbonization study recommend demand-side measures such as energy efficiency or demand response to reduce emissions. Demand-side measures are essential components of decarbonization studies in other states, so it is puzzling why the Michigan study apparently did not include them.

In addition, the Michigan decarbonization study refers to carbon capture in the balanced scenario. Carbon capture and storage is cost-prohibitive for addressing emissions of individual gas consumers.

**Q Is the Company requesting cost recovery for demand-side investments in this filing?**

A No. The Company has not proposed any demand-side measures within this filing.

**Q What are the Company's proposed investments for the EWR programs?**

A The Company received approval in Case No. U-21321 to recover $190 million of gas demand-side program investments for its 2024–2025 EWR plan through surcharges.[17] As shown in Table 1, Consumer's EWR portfolio is projected to achieve 1 percent annual natural gas savings. Planned first-year gas savings reflect the volume of gas saved by measures installed in that year.

[17] Michigan Public Service Commission, Order Approving Amended Settlement Agreement, Case U-21321, October 10, 2024, available at: https://mi-psc.my.site.com/sfc/servlet.shepherd/version/download/068cs00000Ev5PWAAZ.

**Table 1. EWR programs planned investment and energy savings**

| | 2023 (actual) | 2024 | 2025 |
|---|---|---|---|
| **Gas Program Investment** | $99,111,306 | $95,487,640 | $95,066,407 |
| **Planned First-Year Gas Savings (MMcf)** | 3,752 | 2,934 | 2,944 |
| **Projected Gas Retail Sales (MMcf)** | 282,317 | N/A | 308,126 |
| **Planned Gas Savings (% of total)** | 1.3% | 1.0% | 1.0% |

*Source: NGDP Table 7, page 85; Projected Gas Retail Sales (MMcf) values taken from Exhibit A-5 (MA-1) and (MA-5).*

**Q Please describe the Company's Energy Waste Reduction program.**

A Through EWR programs, natural gas utilities in Michigan are required to achieve annual savings of 0.75 percent of total retail sales through 2025, and 0.875 percent of total retail gas sales starting in 2026.[18]

The EWR plan includes both gas and electric measures. The program offers to both gas and electric customers many of the same measures. These include low-flow showerheads and faucet aerators; pipe wrap and air sealing; attic, duct, crawlspace and wall insulation; and Wi-Fi controllable and programmable thermostats. EWR offerings available to gas customers only include gas furnaces and tankless and power-vented water heaters. For electric customers, the Company offers incentives for air-source and mini split heat pumps, heat pump water heaters, central air conditioners, and other measures.[19]

[18] State of Michigan, Public Acts of 2023, Act No. 229 (Public Act 229), effective February 13, 2024, available at: https://legislature.mi.gov/documents/2023-2024/publicact/pdf/2023-PA-0229.pdf.

[19] Consumers Energy 2024-2025 Energy Waste Reduction Plan. August 1, 2023. MPSC Case No. U-21321.

**Q Does the Company offer customers incentives to electrify their building end uses?**

A No, Consumers does not offer natural gas customers any electrification incentives—such as for installing heat pumps to replace gas heating systems—through the EWR programs or otherwise.

**Q Could the Company offer its customers incentives for building electrification?**

A Yes. Public Act 229 provides the Company with new opportunities to earn an incentive from supporting customers transitioning from gas to efficient electric heating equipment. Under this Act, a gas utility can claim gas savings resulting from investments in qualifying efficient electrification measures or envelope efficiency improvements in support of electrification projects towards its gas savings targets.[20]

**Q If the Company were to offer electrification incentives, should these incentives be offered through the existing EWR programs?**

A Not necessarily. Electric energy efficiency programs focus on electric savings only, with goals in terms of reducing MWh, but electrification will increase electric loads rather than produce electric savings. Thus, while electrification

[20] Public Act 229, Sec 77(6): "A natural gas provider may claim natural gas savings resulting from investments in qualifying efficient electrification measures, or investments in building envelope efficiency improvements made as part of projects involving qualifying efficient electrification measures, if the savings are not also counted toward an electric utility's savings goals. When a natural gas provider and an electric provider are both involved in a qualifying efficient electrification measures project, including a project that involves both building envelope efficiency and qualifying efficient electrification measures, the providers shall work together to reach an agreement on how savings claims will be allocated between the providers. The commission may adopt standards or default provisions for the allocation of savings claims between providers that apply if the providers are unable to reach an agreement."

produces gas savings, it works against the goals of the current electric EWR programs. A holistic energy efficiency program would need to consider total combined gas and electric consumption and adopt to fuel-neutral goals (MMBtu) for all measures to accurately account for efficiency-related savings from electrification: i.e. it would look at the efficiency of *energy use* rather than *gas use*.

On the other hand, there are reasons why it makes sense to operate an energy efficiency program and electrification program cooperatively. Energy efficiency and electrification programs can leverage the same outreach dollars to maximize the number of customers reached. Implementers of energy efficiency (particularly for HVAC measures) and building electrification programs both require expertise in building science. And, electrification and energy efficiency programs should work together towards achieving the desired end state of the building; this consideration can help ensure that space heating measures such as heat pumps are sized appropriately and avoid the higher up-front costs associated with oversized heat pump systems.

**Q Do energy efficiency programs typically provide electrification measures?**

A Historically it was not common for utilities with energy efficiency programs to offer incentives for fuel-switching, however it is becoming more common. For example, Mass Save, the energy efficiency administrator in Massachusetts, offers heat pump incentives to customers with electric, gas, or other fuels.[21] The District

[21] Massachusetts Department of Public Utilities D.P.U Docket 21-120 through 21-129, January 31, 2022, available at: https://fileservice.eea.comacloud.net/FileService.Api/file/FileRoom/14461268.

of Columbia's energy efficiency program administrator, the Sustainable Energy Utility, offers higher electrification incentives to gas and oil consumers.[22]

**Q Do you have other comments on the gas EWR programs?**

A Yes. Incentivizing the installation of gas appliances locks in that household's gas consumption for decades, making it more difficult to meet building decarbonization goals. Many gas appliances, and many of the gas energy efficiency measures incentivized by the EWR programs, have long useful lives.[23] For example, a new natural gas furnace typically lasts 20 or more years. For some existing heating equipment such as boilers, the useful life is longer. This means that the opportunity to change some gas measures, such as a heating system, comes very infrequently for many customers (particularly those who lack the ability or financial means to switch their systems early).

Replacing a gas measure in kind (with another gas appliance), which is what the current EWR programs does, perpetuates reliance on the gas system for years or decades into the future. This effectively means that some decarbonization options are not available for customers who received new gas equipment for that period, unless customers are offered higher incentives to replace the equipment before the end of its useful life. In contrast, converting a customer from natural gas to electric heating and cooling near the end of the gas equipment's useful life will be less

[22] District of Columbia Sustainable Energy Utility. Apply for Residential Rebates. https://www.dcseu.com/residential-rebates/apply#:~:text=down%20to%20forms-,Application%20Guide,ups%20and%20electric%20circuit%20additions. Accessed April 17, 2025.

[23] Consumers Energy 2024-2025 Energy Waste Reduction Plan, Case U-21321, submitted August 1, 2023, available at: https://mi-psc.my.site.com/sfc/servlet.shepherd/version/download/0688y000008yCJ8AAM.

expensive for ratepayers, since customers with relatively new gas equipment are unlikely to convert to electric without higher incentives to compensate for the loss of the useful life of the existing equipment.

Also, as a component of a strategy that relies on hybrid heat pumps with gas back-up to meet net-zero emissions, it is likely that more efficient gas equipment will not be cost-effective. This is because gas equipment will be used so little in this scenario, and the additional cost of the high efficiency gas equipment may not be recovered in savings that accrue during just a few hours per year.

In recognition of this reality, some states have ended incentives for gas appliances. In Massachusetts, to align with the 2021 Climate Act, the utilities have discontinued rebates, incentives, and financing for natural gas, oil, and propane.[24] Likewise, the District of Columbia ceased offering incentives for gas-only measures.[25]

**Q Do you have other comments on Consumers' approach to electrification and demand-side management?**

A Yes. When geographically targeted, electrification and demand-side management programs can save costs by avoiding traditional infrastructure investments, such aging pipe replacements.

[24] MassSave. 2024 Discontinuation of Rebates and Incentives for Natural Gas, Oil, and Propane Heating Equipment. Available at: https://www.masssave.com/blog/residential/discontinuation-of-rebates-and-incentives-natural-gas-oil-propane-heating-equipment.

[25] Building Electrification Institute. Washington, DC. https://beicities.org/washington-dc#:~:text=Building%20in%20part%20on%20BEI's%20customer%20economics,investments%20strongly%20encourage%20electrification%20across%20the%20District.

**Q What are non-pipeline alternatives?**

A As discussed in Dr. deLeon's testimony, non-pipeline alternatives ("NPA") are solutions that meet customer energy needs and are alternative to traditional infrastructure investments. NPA portfolio components include demand-side measures such as electrification, energy efficiency, and other measures that reduce or eliminate customers' demand for natural gas. By decreasing gas combustion, NPAs reduce emissions and can provide health benefits associated with improved indoor air pollution.

**Q Is Consumers proposing to implement any NPAs at this time?**

A No, Consumers is not proposing to implement any NPAs in place of pipe replacement, new customer connections, or other traditional infrastructure investments. Nor is the Company assessing opportunities to implement NPAs within its current planning processes.

**Q What are your recommendations?**

A Prior to the next EWR Plan, due to be filed this summer, the Commission should initiate a process to reconsider the measures of the EWR programs in order to align them with the state's climate targets, to account for the greater efficiency of electrification measures relative to gas. (That is, heat pumps commonly have efficiencies of 200 to over 300 percent, reaching as high as 440 percent, while gas furnaces top out at about 98 percent efficiency.[26]) Rather than promoting gas-

[26] Paige Jadun, Colin McMillan, Daniel Steinberg, Matteo Muratori, Laura Vimmerstedt, and Trieu Mai. 2017. Electrification Futures Study: End-Use Electric Technology Cost and Performance Projections through

burning equipment that constrains consumers' ability to choose alternatives such as electrification, as the Company is currently doing, the focus of the gas efficiency program should be on electrification measures as well as weatherization and building envelope measures. Also, as discussed in Dr. deLeon's testimony, the Commission should require consideration of NPAs.

**Q Why are you recommending a change to EWR programs in this docket, rather than in the docket that will be opened when the new EWR plan is filed?**

A The EWR plan savings and design are relevant in this rate case, since they inform Consumers' investment plan. Furthermore, Consumers' decarbonization strategy is based on the EWR plan, which is currently aimed in the wrong direction in terms of achieving climate targets.

## IV. THE COMPANY'S LINE EXTENSION POLICIES SUBSIDIZE NEW GAS CONNECTIONS

**Q Please describe the Company's new business program.**

A The new business program is comprised of three subprograms: the Customer Attachment Program; Large New Business; and Mains, Services, and Meter Stands. The Customer Attachment Program, which ended in 2019, was designated to convert customers to natural gas—any remaining costs incurred as this program

2050. Golden, CO: National Renewable Energy Laboratory. NREL/TP-6A20-70485. Figure 20. Available at: https://www.nrel.gov/docs/fy18osti/70485.pdf;

Brand, L. and W. Rose. 2012. Measure Guideline: High Efficiency Natural Gas Furnaces. U.S. Department of Energy for The National Renewable Energy Laboratory. Available at: https://www.nrel.gov/docs/fy13osti/55493.pdf#:~:text=A%2520link%2520to%2520the%2520DOE%2520EIA%2520Energy,efficiency%2520furnaces%2520have%2520an%2520AFUE%2520of%252090%25%252D98%25.

winds down will be tracked under Mains, Services, and Meter Stands category.[27] The Large Business Program is for new connections projected to exceed $500,000.[28] All other expenditures appear to fall under the category for Mains, Services, and Meter Stands. Table 2 shows historical expenditures for the entire New Business program.

**Table 2. New Business historical expenditure (nominal dollars)**

| | 2019 | 2020 | 2021 | 2022 | 2023 |
|---|---|---|---|---|---|
| **New Business ($000)** | $86,498 | $87,021 | $55,373 | $74,088 | $76,320 |

*Source: Testimony of Lincoln D. Warriner, p. 9.*

**Q What are the Company's proposed investments for new customer connections?**

A The Company proposes to spend $184 million on new business between 2024 and 2026,[29] which is a 12.7 percent decrease from historical expenditure as Witness Warriner points out.[30] However, the Company is forecasting a stable, slightly increasing number of new connections annually despite the historical declines in numbers of new connections.[31]

[27] Direct Testimony of Company Witness Lincoln D. Warriner, page 16 and 21.

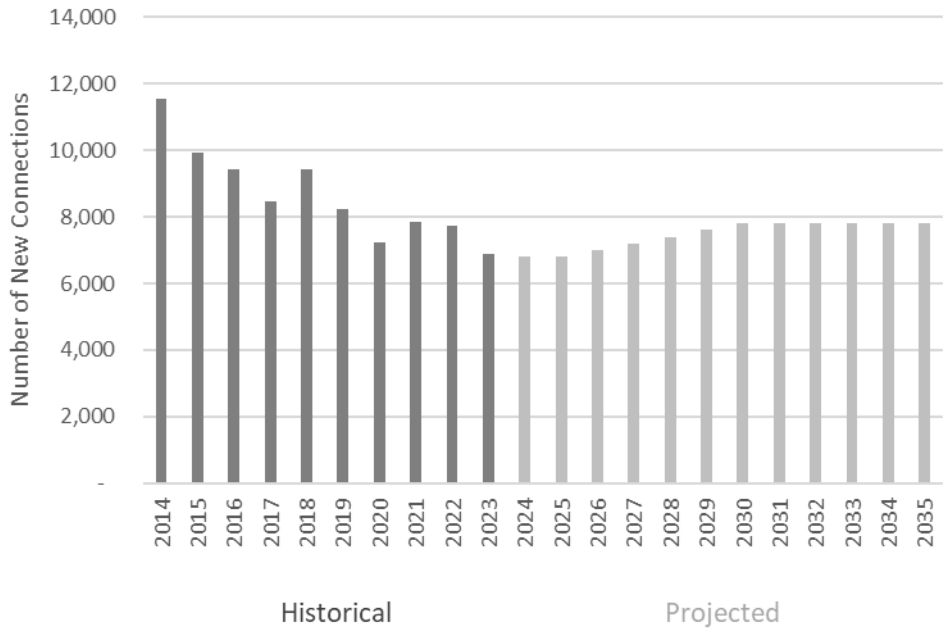
[28] Warriner Testimony, page 22.

[29] Warriner Testimony, page 12.

[30] Warriner Testimony, page 8.

[31] NGDP, page 60.

**Figure 1. New customer connections**




*Source: NGDP, page 60.*

**Q What are the Company's customer attachment policies and practices?**

A The residential gas-only footage allowance for new connections in 2025 is 117 feet, or 152 feet for joint gas and electric hookups.[32] Footage allowances increased from 2024 when gas-only allowances were 88 feet and joint gas and electric allowances were 124 feet.[33] Longer footage allowances result in lower costs for new customers and greater costs spread across ratepayers. There are no footage allowances for commercial customers.[34]

Residential customers who exceed the footage allowance are responsible for a flat $200 revenue deficiency charge, an excess footage charge for gas-only connections of $21.26 per foot beyond the footage allowance ($17.28 for joint

[32] Ex MEC-5, Discovery Response attachment MNSC-CE-0599_Warriner_ATT_1.

[33] Ex MEC-5, Discovery Response attachment MNSC-CE-0599_Warriner_ATT_1.

[34] Ex MEC-6, Discovery Response MNSC-CE-0595.

gas and electric hookups),[35] and a connection fee and direct charges for things such as permitting and inspections.[36] In lieu of the simplified $200 charge, non-residential customers are responsible for a revenue deficiency charge that considers the cost of the connection and future revenues from the new customer.

**Q Please characterize Consumers' historical line extension costs and customer contributions in aid of construction.**

A Table 3 shows the Company's actual costs incurred from new connections (excluding large business), the amount of costs covered by customers who paid a contribution for their new connection, and the share of total costs socialized across ratepayers. On average, new customers pay about 10 percent of line extension costs upfront, and the rest is covered by the Company in its rates. This arrangement means that the investment risk is initially borne by ratepayers: if new customers do not remain on the gas system for as long as the Company projects, or if new customers do not purchase gas in the quantities that Consumers expects, then remaining customers will be left to cover the costs. If the customer disconnects from the gas system sooner than expected by the Company, the costs of connection are sunk.

[35] Ex MEC-6, Discovery Response MNSC-CE-0595.

[36] Ex MEC-7, Discovery Response MNSC-CE-0024 and attachment 1.

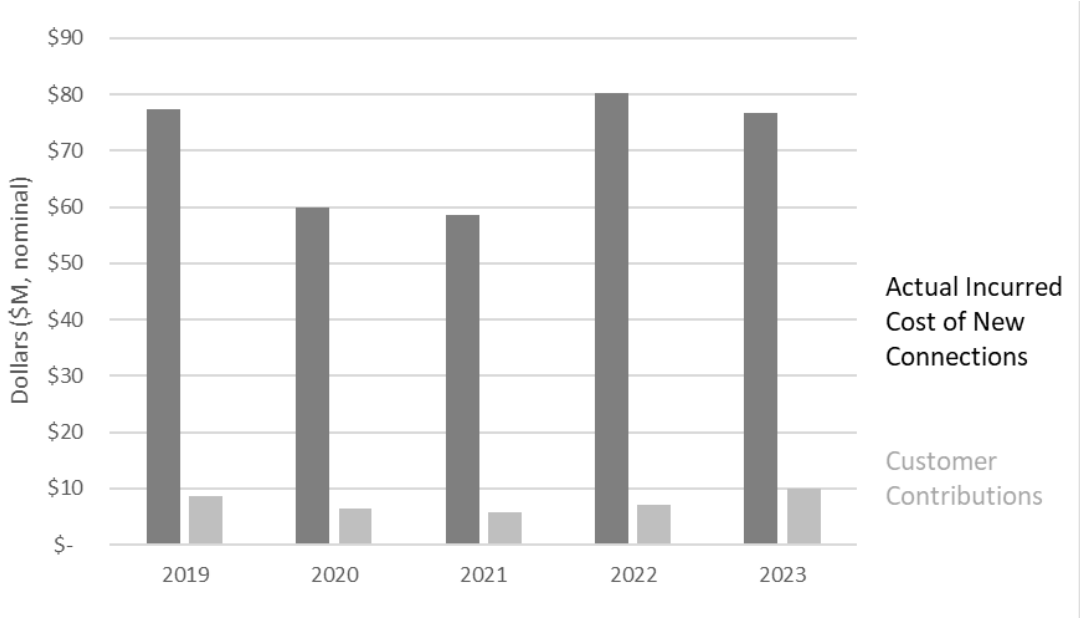
**Table 3. New connections: number, costs (nominal dollars), and percent of costs covered by ratepayers**

| | 2019 | 2020 | 2021 | 2022 | 2023 |
|---|---|---|---|---|---|
| **Number of New Connections** | 8,223 | 7,236 | 7,861 | 7,719 | 6,870 |
| **Actual Incurred Costs of New Connections ($000)** | $77,298 | $59,905 | $58,670 | $80,283 | $76,800 |
| **Customer Contributions ($000)** | $8,714 | $6,325 | $5,703 | $7,042 | $9,852 |
| **Percent of Total Connection Costs Borne by Ratepayers** | 89% | 89% | 90% | 91% | 87% |

*Source: Ex MEC-7, MNSC-CE-0024.*

*Note: values exclude new connections for large businesses.*

**Figure 2. Cost of new connections (millions of nominal dollars), 2019-2023**




*Source: Ex MEC-7, MNSC-CE-0024.*
*Note: values exclude new connections for large businesses.*

**Q What are Consumer's assumptions for calculating revenue deficiency charges for residential customers?**

A The Company calculates a revenue deficiency charge for new connections that exceed the footage allowance. For residential customers, this is a flat $200 charge. By default, Consumers assumes that new customer sales will be equivalent to the three-year historical average sales for that customer class, and the customer will remain connected to the gas system for 20 years.[37]

**Q How was the $200 flat charge for residential customers determined?**

A It is not clear how this was determined and what it covers.

**Q How was the excess footage charge for residential customers calculated?**

A Consumers states that is calculates the excess footage charge as the incremental cost associated with the installation of an additional foot of service past the length of the allowance.[38] As of March 1, 2025, the Company charges residential customers a fixed excess footage charge of $21.26 for gas-only connections and $17.28 for joint gas and electric connections. The Company states that these fixed charges were calculated in the same way as described above.[39] However, it is unclear what data Consumers used to produce these calculations, how frequently the Company updates excess footage charges, and why Consumers decided to switch to a fixed model in the first place.

[37] Ex MEC-8, Discovery Response MNSC-CE-0026 (partial – Warriner).

[38] Ex MEC-6, Discovery Response MNSC-CE-0595.

[39] Discovery Response MNSC-CE-0772.

**Q What are Consumer's assumptions for calculating revenue deficiency charges for non-residential customers?**

A For non-residential customers, the Company calculates revenue deficiency as the net present value of line extension costs minus expected future revenues from the new customer. Consumers takes into account equipment specifications, load diversification, and annual usage patterns to calculate a constant level of new customer sales, and the Company assumes the customer will remain connected to the gas system for twenty years.[40]

**Q Does the Company use a model for estimating the revenue deficiency?**

A Yes, but Consumers has not provided the model, despite the terms of the U-21148 settlement which called for Consumers to transition to a new model that was transparent and capable of being shared with stakeholders by the end of 2022.[41] Without this model, it is difficult to ascertain the adequacy of the model for its intended purpose. That is, is the new connection likely to be financially neutral for ratepayers within the period that the new customer is assumed to remain on the system (i.e. 20 years) and assuming the new customer's gas consumption is equal to the rate-class average?

**Q Is it reasonable to assume new customers will stay on the system for 20 years?**

A No. As discussed in the testimony of Dr. deLeon, the Company is proposing large capital investments in its system. With large investments in the gas system pushing

[40] Ex MEC-7, Discovery Response MNSC-CE-0026 (partial – Warriner).

[41] Michigan Public Service Commission. 2022 (July 7). Order Approving Settlement Agreement. Case No. U-21148. Attachment A: Settlement Agreement, p. 4.

up gas rates, as well as market shifts and policies that favor electrification, many customers who have the financial means to electrify their end uses will do so and may leave the gas system.

**Q Is it reasonable to assume new customers will purchase as much gas as existing customers?**

A No. Given overall declines in gas consumption for residential customers and trends in heating equipment toward electrification, as discussed in Section V, it is unlikely that the historical average consumption for all residential customers accurately predicts new customer usage. Many new connections are for new construction. In new construction, electric options are generally competitive with or lower cost than gas alternatives.[42] If, for example, new customers seek gas for cooking but elect highly efficient heat pumps for space heating, then it is unlikely that ratepayers will recoup the costs of connecting that customer for many years.

**Q Does Consumers track whether actual usage and revenue conform to or are even within range of the assumptions?**

A No.[43]

[42] Heat pumps are usually the lowest-cost option for newly constructed homes, since a heat pump can avoid the need for a furnace and an air conditioner. (RMI, The Economics of Electrifying Buildings: How Electric Space And Water Heating Supports Decarbonization of Residential Buildings, 2018.) Also, Lawrence Berkeley National Laboratory and National Renewable Energy Laboratory found that 59% of homes with gas heating and a central AC would produce overall savings if retrofit with heat pump (Figure S7, Wilson et al., Heat pumps for all? Distributions of the costs and benefits of residential air-source heat pumps in the United States. Joule 8, 1000–1035 April 17, 2024. Published by Elsevier Inc. Available at https://doi.org/10.1016/j.joule.2024.01.022.)

[43] Ex MEC-9, Discovery Response MNSC-CE-0031.

**Q Why should Consumers track actual usage and revenue from new connection customers?**

A Without tracking this information, there is no way for Consumers or the Commission to know whether the Company's revenue deficiency calculations are accurate. If Consumers is overestimating new customer revenues, that means it is undercharging new customers for construction costs, and remaining ratepayers are left shouldering the burden resulting from inaccurate allocation methods. A more prudent action is to track, analyze, and report new customer consumption and regularly revise assumptions for calculating new customer contributions to reflect actual customer revenues.

**Q What are the implications of the Company's line extension policies?**

A The Company's line extension policies incentivize new customer connections by subsidizing the true cost of gas line extensions. They do this by (a) providing a line extension allowance and (b) using likely outdated assumptions for household gas consumption and the number of years a new customer is expected to remain on the system. There is significant risk associated with the Company's decision to subsidize new customer connections, made worse by the uncertainty of future consumption levels and the period of time a new customer will remain on the system. This risk falls almost entirely on existing ratepayers, who pay most of the upfront costs of new connections.

**Q Did the Commission address this issue in the DTE Gas case?**

A Yes. The Commission declined to order a change in DTE's CIAC but expressed clear concern about the disconnect between CIAC methods and the energy transition or declining gas use. Further, the Commission ordered DTE Gas to "provide a thorough justification for its CIAC and CAP methodology, including whether it is appropriate to revise its assumptions to include declining gas demand, customer adoption rates for the CAPs based on historical experience when calculating new attachment surcharges, and how the company intends to avoid subsidization by existing customers" in its next general rate case.[44]

**Q Are you aware of other states that have eliminated or reduced line extension allowances?**

A Yes. In states like California and Colorado, Commissions have eliminated these subsidies entirely for residential customers, partly because of concerning assumptions about continued gas demand.[45,46] In Oregon, the Commission ordered NW Natural to step down its allowance to three times annual margin revenue generated by the new non-residential customer.[47]

[44] Michigan Public Service Commission, Order, In the Matter of the Application of DTE Gas Company for Authority to Increase its Rates, Amend its Rate Schedule and Rules Governing the Distribution and Supply of Natural Gas, and for Miscellaneous Accounting Authority, Case No. U-21291, November 7, 2024.

[45] California Public Utility Commission, Decision 22-09-026 in Rulemaking 19-01-011, September 15, 2022, available at: https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M496/K987/496987290.PDF.

[46] Colorado Senate Bill 23-291, Section 5, 40-3.2-104.3, available at: https://leg.colorado.gov/sites/default/files/2023a_291_signed.pdf.

[47] Public Utilities Commission of Oregon. Order No. 22-388 in case UG 435. October 24, 2022.

**Q Do you have any recommendations?**

A Yes. I recommend that the Commission order the Company to reduce the allowance for new customer line extension costs to 50 percent of total costs, starting with the test year. Doing so would better protect ratepayers from the risk that new customer connections might not produce the revenue forecasted by the Company. Further, it would reduce incentives to expand the gas system and thereby better align Consumers' CIAC policies with Michigan's emission reduction targets.

**Q What is the impact of this recommendation on the Company's projection of gas distribution capital expenditures?**

A The Company projects test year New Business capital expenditures for the 12 months ending 10/31/2026 of $66,645,000.[48] Reducing this projection to cover only 50 percent of new connection costs results in revised, projected test year New Business capital expenditures of $37,025,000.[49] The Commission should order the Company to reduce its New Business capital expenditures for the test year to this amount.

**Q Why do you recommend reducing the allowance to 50 percent specifically?**

A Consumers did not provide the revenue deficiency model, which limited my ability to quantify a fraction with a basis in the data. Nevertheless, new customers should be responsible for much more than they are currently paying toward

[48] Exhibit No. A-12, Schedule B-5.9 (LDW-1).

[49] Consumers has been covering roughly 90 percent of average new connection costs. To adjust the current average coverage to 50 percent, I multiplied $66,645,000 by 50%/90% to get $37,025,000.

connection costs. Given the emission reduction targets and in fairness to existing ratepayers, it may be appropriate to eliminate the allowance entirely, as other states have done. However, in the interest of conservatism and gradualism, I propose an allowance of 50 percent.

## V. NEW CONNECTION FORECASTING APPEARS TO BE FLAWED AND IS INCONSISTENT WITH DECARBONIZATION POLICIES

### i. Load forecasting

**Q What level of gas load growth is the Company projecting and how does this forecast compare with historical growth rates?**

A As shown in Table 4, the forecast compound annual growth rates (CAGR) of residential and industrial sales are slightly higher than recent historical data, while for the commercial sector Consumers' forecast growth rate is slightly lower than historical growth.[50]

**Table 4. Historical and forecast growth of weather-normalized deliveries by customer class**

| | Historical CAGR (2016–2023) | Forecast CAGR (2025–2029) |
|---|---|---|
| Residential | -0.3% | -0.1% |
| Commercial | 0.3% | -0.1% |
| Industrial | -2.3% | -1% |

[50] Calculation of CAGR from 5-Year Forecasted Natural Gas Cycle Deliveries and Customer Count by Class, Part III – Standard Filing Requirements, Attachment 015 and Attachment 016.

**Q How did the Company estimate the load forecast?**

A The Company used econometric regression models to estimate its dependent variables, customer count, and gas delivery by "class (residential, commercial, and industrial) and service type (sales and transportation)."[51]

**Q What is a regression model?**

A Regression models estimate the relationship between a dependent variable and independent variables using historical data. The estimated relationship, called a coefficient, is then applied to forecast independent variables to estimate the value of the dependent variable in the forecast period.

**Q How does the Company measure the fit of its regression model?**

A Consumers measured how well the regression models estimate the relationship between independent and dependent variables using an adjusted coefficient of multiple determination ($R_{\alpha}^{2}$) and Mean Absolute Percent Error (MAPE).[52] Additionally, t-statistics and p-values indicate whether independent variables are statistically significant.[53] The models provided in Part III Attachment 027 incorporate statistically significant independent variables, and each model provides a high $R_{\alpha}^{2}$ and low MAPE, indicating that the models provide a reasonably good fit.

[51] Direct Testimony of Company Witness Mustafa Ahmed, p. 3 line 18-19.

[52] Ahmed Direct Testimony, p. 6, line 18-21.

[53] Ahmed Direct Testimony, p. 7, line 15-21.

**Q What issues do you have with how the Company conducts its regression modeling?**

I have concerns with the lack of incorporation of out-of-sample data in the review of the regression models as well as the lack of incorporation of the effects of Senate Bill 273.

**Q Should the Company incorporate out-of-sample data into its regression modeling?**

A I believe that the Company should incorporate estimates of out-of-sample historical data when constructing its regression model. The regression model currently contains each year of the independent and dependent variables, leaving no data out of the sample that was used to estimate the regression models. By not incorporating out-of-sample data into the regression model, the Company is missing out on the ability to assess how the regression model performs on data not included in the regression periods.

Witness Ahmed states that the Company's forecasting methods are accurate partially as demonstrated against historical results.[54] However, the historical data used to estimate the regression model is the same historical data which the regression is being judged against. Thus, it does not demonstrate great performance relative to actual historical data as it is within the regression data sample.

[54] Ahmed Direct Testimony, p. 8, line 1 – 4.

**Q Please explain how Public Act 229 affects Consumers' forecasting.**

A Public Act 229, enrolled as Senate Bill 273, allows both gas companies and electric companies to implement electrification measures, starting on January 1, 2025.[55] This provision can help households and businesses using gas heating switch to electric heating, leading to substantial reduction in gas use in the coming years. Consumers stated, "Given that Senate Bill 273 has not passed, the Company views it as a signpost to monitor and has not performed a full analysis on its potential impacts to natural gas sales."[56] However, this bill was in fact passed on November 28, 2023 and became effective on February 13, 2024.[57] With the passage of Senate Bill 273 as Public Act 229, Consumers should be able to save more gas if such measures can provide annual average energy cost savings.[58] The passage of this Act affects all aspects of Consumers operations over the forecasting period of 2025–2029.

**Q Please explain how the new connections forecast differs from the total residential sales customer count forecast.**

A As I explain below, the Company separately forecasts the number of new connections. The new connections forecast is conducted independently of the total customer count forecast and is not used in estimating the total customer count

[55] Senate Bill 273 of 2023 (Public Act 229 of 2023). Available at: https://www.legislature.mi.gov/Bills/Bill?ObjectName=2023-SB-0273.

[56] Ex MEC-10, Discovery Response MNSC-CE-0018 (partial – Dreisig).

[57] Senate Bill 273 of 2023 (Public Act 229 of 2023). Available at: https://www.legislature.mi.gov/Bills/Bill?ObjectName=2023-SB-0273.

[58] Senate Bill 273. Section 72(1)(c) and Section 77(6)

forecast or total sales forecast.[59] That is, the historical total customer count used to forecast total customers changes by net new customers every year. However, the total customer count forecast does not incorporate information from the new customer forecast into the total customer forecast. The Company should clarify why it does not incorporate information from its new customer forecast into its total customer forecast.

**ii. New connection forecasting**

**Q What did the Company assume for new connections?**

A Consumers assumed a 3 percent annual growth rate for new connections from 2026 through 2030, except for 2029, when it assumes no growth.[60] Consumers states that the housing market is anticipated to grow, driven by anticipated reductions in inflation rates and mortgage rates, and that this projected growth is the main reason for its assumed 3 percent growth rate.[61] This implies that low inflation rates and low mortgage rates would support a high growth rate of 3 percent for customer connection. However, Consumers also stated that "No specific analysis or detailed assumptions were utilized to develop that estimated growth rate."[62]

[59] Discovery response MEC-CE-0723 a. – c.

[60] Ex MEC-11, Discovery Response MEC-CE-20 Warriner ATT 4.

[61] Ex MEC-11, Discovery Response MEC-CE-20 Warriner ATT 4.

[62] Ex MEC-12, Discovery Response MEC -CE-0585, part c.i.

**Q Are there any issues with the Company's forecasts for new connections?**

A Yes. First, the Company's assumption for new connections contradicts the historical trend of customer connections. As shown in Figure 1 above, while the Company has continued connecting new customers since 2024, the number of new customer connections has declined significantly—from approximately 11,500 in 2014 to 6,870 in 2023—representing an average annual decrease of 6 percent. Between 2014 and 2020, prior to the pandemic, 30-year fixed mortgage rates remained around 4 percent, while inflation averaged between 1.5 and 2 percent (with the exception of 2015).[63] Notably, even during this period of relatively low mortgage rates, the number of new customer connections in Consumers' service territory continued to decline. Today, mortgage rates have risen to approximately 7 percent.[64] The Company projects a 3 percent annual increase in new customer connections, based on the assumption that both inflation and mortgage rates will decline in the coming years. However, even if mortgage rates were to halve to 3.5 percent, this value would still align with historical periods during which customer connections were decreasing. As such, the Consumers' assumption of a significantly increased gas connection rate of 3 percent is not supported by historical data.

Second, the HSTART value used to develop the total residential customer count forecast has negative growth during the forecast period of 2025–2029 with a

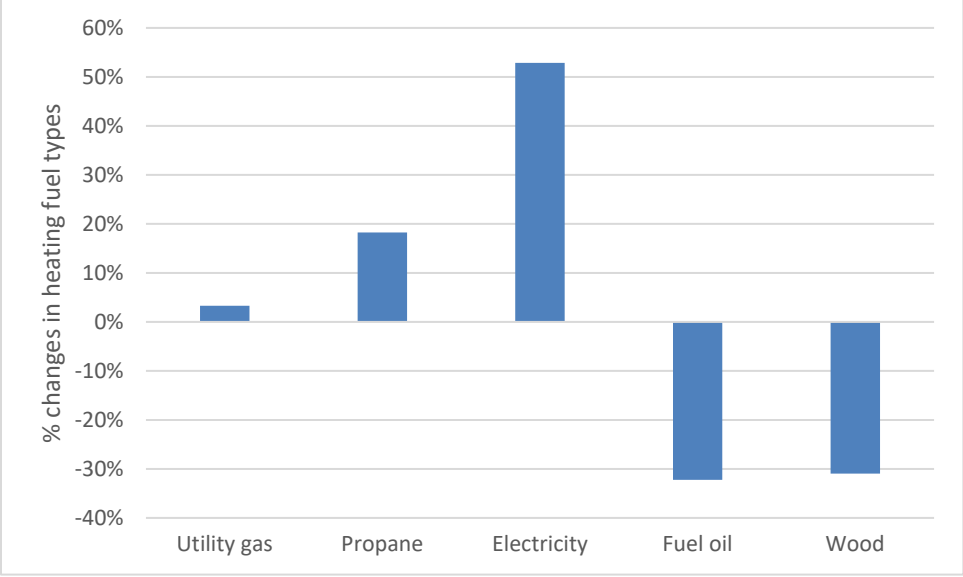
[63] FRED Economic Data. "30-Year Fixed Rate Mortgage Average in the United States" Available at: https://fred.stlouisfed.org/series/MORTGAGE30US; FRED Economic Data. "Inflation, consumer prices for the United States." Available at: https://fred.stlouisfed.org/series/FPCPITOTLZGUSA.

[64] FRED Economic Data. "30-Year Fixed Rate Mortgage Average in the United States" Available at: https://fred.stlouisfed.org/series/MORTGAGE30US

CAGR of -1.47 percent, indicating that housing starts are not expected to grow during the forecast period.[65] The HSTART variable is not defined but presumably measures the amount of housing starts in the defined time period on an indexed basis.

Third, Consumers' forecast does not reflect recent market trends or policies, either. Over the past decade, the adoption of new electric heating has increased considerably, while the adoption of new gas heating has declined. According to the U.S. Census Bureau's American Community Survey, the number of Michigan households using electric space heating increased by 53 percent in 2023 relative to 2014. In contrast, households using utility gas heating grew by only 3 percent, and those using propane increased by approximately 19 percent during the same period, as shown in Figure 3 and Table 5. Meanwhile, the number of households using wood or fuel oil for space heating declined substantially—by 31 percent and 32 percent, respectively.

**Figure 3. Changes in heating fuel types relative to 2014 (% change)**




[65] Ex MEC-13, Part III Attachment 028, HSTART.

*Source: American Community Survey, Michigan Summary. https://data.census.gov/table/ACSDP1Y2014.DP04?g=040XX00US26 and https://data.census.gov/table/ACSDP1Y2023.DP04?g=040XX00US26.*

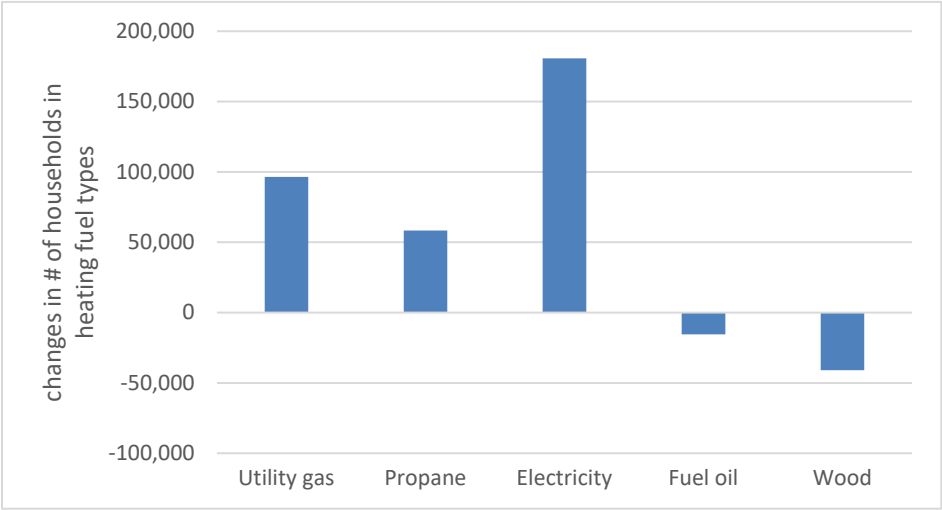
**Table 5. Michigan heating fuel types, 2023 and 2014, in number of households, percent change, and annual growth rates**

| | 2023 | 2014 | Changes in heating fuel types (# of households) | Changes in heating fuel types (%) | Annual growth rate |
|---|---|---|---|---|---|
| **Utility gas** | 3,039,167 | 2,942,704 | 96,463 | 3% | 0.4% |
| **Propane** | 372,796 | 314,434 | 58,362 | 19% | 1.9% |
| **Electricity** | 523,137 | 342,353 | 180,784 | 53% | 4.8% |
| **Fuel oil** | 32,099 | 47,572 | -15,473 | -33% | -4.3% |
| **Wood** | 88,484 | 129,455 | -40,971 | -32% | -4.1% |
| **Other*** | 52,126 | 58,056 | 5,930 | 10% | 1.2% |

*Note: *includes solar, no fuel used, coal or coke, and other fuel.*

Figure 4 below shows the change in the number of households by heating fuel type between 2014 and 2023. During this period, the number of gas-heated homes increased by approximately 96,000, while electric-heated homes increased by about 180,000—nearly twice as much. This indicates a clear trend of households increasingly choosing electric heating over gas heating in the past decade.

**Figure 4. Changes in heating fuel types relative to 2014 (number of households)**




*Source: American Community Survey, Michigan Summary. https://data.census.gov/table/ACSDP1Y2014.DP04?g=040XX00US26 and https://data.census.gov/table/ACSDP1Y2023.DP04?g=040XX00US26.*

**Q What do you find with respect to the new connections forecast?**

A I find that the methodology for the new connections forecast is flawed and is unlikely to reflect future connections. Further, I find that the Company has failed to provide justification for its assumption that new connections will grow by 3 percent per year. A more reasonable assumption for the growth rate for new connections zero or less than zero.

I also find that the link of the new connections forecast to the load forecast in general is not clear, in terms of the functions of these two forecasts.

**Q What do you recommend?**

A The Commission should order the Company to set the growth rate in new connections to zero. As described above, I recommend that the Company's test year capital expenditures for New Business for the 12 months ending 10/31/2026

be reduced to $37,025,000 to only cover 50 percent of new connection costs. Backing out 3 percent growth from this revised figure, I calculate that the revised New Business capital expenditures, accounting for both a 50/50 cost share on new connection costs and for an assumption of flat new connections growth, should be $35,946,602.[66]

In addition, the Commission should require the Company to explain and document the relationship of the new connections forecast to the load forecast.

**Q Does this complete your direct testimony?**

A Yes, it does.

[66] $37,025,000/1.03=$35,946,602.

MR. BZDOK: At this time, on behalf of MEC and Sierra Club, would I move to bind into the record the revised direct testimony of Sol deLeon, consisting of a cover page, lists of tables and figures and contents, and 45 pages of questions and answers, and I would move for the admissions of Exhibits MEC-14 and MEC-15.

JUDGE VARCHETTI: All right. Are there any objections to the admission of Dr. deLeon's revised direct or the associated exhibits?

I am hearing none, so the testimony is bound into the record and the exhibits are admitted.

MR. BZDOK: Thank you, Your Honor.

(Revised Direct Testimony bound in)

**STATE OF MICHIGAN**

**MICHIGAN PUBLIC SERVICE COMMISSION**

| | |
|---|---|
| In the matter of the Application of **CONSUMERS ENERGY COMPANY** for authority to increase its rates for the distribution of natural gas and for other relief. | Case No. U-21806 |

# REVISED DIRECT TESTIMONY OF

# DR. SOL DELEON

# ON BEHALF OF

# MICHIGAN ENVIRONMENTAL COUNCIL AND SIERRA CLUB

May 28, 2025

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**DIRECT TESTIMONY OF DR. SOL DELEON FOR MEC & SC**
**CASE NO. U-21806**

## I. INTRODUCTION AND PURPOSE OF TESTIMONY

**Q Please state your name and occupation.**

**A** My name is Sol deLeon. My business address is 485 Massachusetts Ave., Suite 3, Cambridge, Massachusetts 02139. I am a Principal Associate at Synapse Energy Economics, Inc. I work primarily in Synapse's consulting for future of gas utilities practice, and I also work in the related area of building decarbonization technology and policy.

**Q Please describe Synapse Energy Economics.**

**A** Synapse Energy Economics is a research and consulting firm specializing in electricity and gas industry regulation, planning, and analysis. Our work covers a range of issues, including economic and technical assessments of demand-side and supply-side energy resources, energy efficiency policies and programs, integrated resource planning, electricity market modeling and assessment, renewable resource technologies and policies, and climate change strategies. Synapse works for a wide range of clients, including state attorneys general, offices of consumer advocates, trade associations, public utility commissions, environmental advocates, the U.S. Environmental Protection Agency, U.S. Department of Energy, U.S. Department of Justice, the Federal Trade Commission, and the National Association of Regulatory Utility Commissioners. Synapse's staff includes over 35 professionals with extensive experience in the electricity and gas industries.



VERITEXT LEGAL SOLUTIONS

**Q Please describe your professional experience at Synapse Energy Economics and before beginning your current position at Synapse.**

**A** I have over 25 years of experience in the energy industry, primarily in U.S. natural gas distribution utilities and international merchant electricity generation. I analyze gas utility applications and filings before state public service commissions, in addition to developing studies, reports, and other materials regarding gas utility investments, business models, ratemaking, depreciation, revenue requirements, and business risk. Prior to joining Synapse, I was a project manager at Washington Gas & Light Company, working on initiatives for corporate governance, renewable natural gas ("RNG"), and greenhouse gas ("GHG") emissions reduction inventories. Before that, I worked for AES Corporation where I conducted risk analysis on commodity prices, interest rates and foreign exchange rates, developed models for derivative valuation and electric generating asset project valuation. I completed my Masters in Business Administration and my Doctorate in Liberal Studies at Georgetown University. My doctorate focused on energy transition and energy justice. My complete CV is attached as Exhibit MEC-14.

**Q On whose behalf are you testifying in this case?**

**A** I am testifying on behalf of Michigan Environmental Council and Sierra Club.

**Q Have you previously testified before the Michigan Public Service Commission ("the Commission")?**

**A** No.

**Q What is the purpose of your testimony?**

**A** The purpose of my testimony is to explain the impending energy transition and its impacts on ratepayers, and then to evaluate Consumers Gas ("Consumers" or "the Company") planned capital investments within the context of the energy transition. I will also address the need to develop a long-term planning perspective and to introduce the value of using risk mitigation effectiveness measures as a tool to select and prioritize capital projects.

**Q Are you sponsoring any exhibits in this proceeding?**

**A** Yes, I am sponsoring the following exhibits:

- Exhibit MEC-14: CV of Dr. Sol deLeon
- Exhibit MEC-15: State Survey White Paper

## II. FINDINGS AND RECOMMENDATIONS

**Q Please summarize your primary conclusions.**

**A** My findings include the following:

- The future of natural gas will not be like the past or the present. Changes driven by climate policy, changing markets, and the availability of alternatives will have an impact on demand. Michigan has established policies and conducted regulatory processes that the Company could have used to inform its planning. In addition, the Company has developed its own climate objectives to support the state's decarbonization targets. Thus, the Company has sufficient information to be taking prudent actions, as described in this testimony, to adapt to a changing future.

- The Company's lack of good planning practice makes imprudent investment likely.
- The Company has not made the appropriate evaluations to determine that the continued spending on gas distribution infrastructure is the best way to achieve goals of safety, affordability, and emission reductions.
- The Company does not undertake well-established practices to consider non-pipeline alternatives ("NPA") to its capital investments.
- The Company's approach to prioritizing leak-prone pipe for replacement does not account for the actions that need to be undertaken to meet the state's GHG emission reduction goals or the Company's scope 3 emission reduction targets, nor does it attempt to maximize the risk reduction of ratepayer spending.
- The Company has not initiated an NPA process within its long-term gas planning to ensure that investments meet affordability and clean energy objectives.

**Q Please summarize your recommendations.**

**A** Based on my findings, I offer the following recommendations:

- The Commission should find that the Company's planning process is flawed because it does not incorporate planning for the energy transition. The Commission should direct the Company to update its practices to align with planning for the Company's and Michigan's climate objectives. This should

include requiring the Company to include the forecasted yearly sales for each major customer class for the 10-year gas delivery planning horizon.

- The Commission should open a docket for the purpose of establishing a common framework and planning parameters, including consideration of NPAs and other alternatives, for the future of the natural gas system in Michigan.

- The Commission should require Consumers to evaluate NPAs in place of traditional gas infrastructure investments before the Company can seek cost recovery of those traditional investments. This should include evaluation of electrification as an alternative to service line replacement.

- The Commission should set forth minimum requirements for an NPA framework, including but not limited to benefit-cost analysis, project size, type of project, timeline for implementation, and alternatives to consider. The Commission should then launch an inclusive stakeholder process to develop the details of the NPA framework, with participation by all electric and gas utilities in the state along with other stakeholders.

- Consumers should provide much greater transparency regarding the tradeoffs between safety and affordability—on a regular basis and in its requests for approval to include expenditures in rate base—through probabilistic risk modeling and calculation of cost-effectiveness. This includes, but may not be limited to:

- Reporting on transmission-level projects that demonstrates how Consumers utilizes cost-effectiveness, where applicable, to maximize safety impacts for the ratepayer dollars spent. Calculations and assumptions should be available to stakeholders upon request.
- Enhanced Infrastructure Replacement Program ("EIRP") reporting should include risk ranking information (risk rank of asset remediated and total number of assets) and narrative descriptions regarding the use of risk ranking driving remediation for a particular project.

- When probabilistic risk models are available for distribution assets starting in the next rate case, Consumers should do the following:
  - Calculate and utilize total risk reduction and cost-effectiveness statistics as an important input into selecting appropriate projects and related remediations. Make cost-effectiveness statistics and all inputs and assumptions available to stakeholders upon request, including the ability to calculate risk reduction and cost-effectiveness for alternative projects and remediations.
  - Ensure its EIRP reports summarize remediations examined, describe the cost-effectiveness of projects relative to alternatives, and indicate why the Company's remediation was selected.
- The Commission should require future rate case applications, starting with Consumers' next rate case, to utilize probabilistic risk modeling and cost-effectiveness calculations to a much greater extent for all asset classes.

Consumers should make this modeling available upon request to stakeholders and the Commission, including the following:

- Unless Consumers can demonstrate it is not possible, the Company should develop probabilistic risk models for use in the next rate case for all asset classes (distribution, storage wells, etc.).
- For each project proposed in the test year, Consumers should calculate the risk reduction, cost, and cost-effectiveness (measured as risk spend efficiency, or "RSE") of its expenditures. The Company should make all workpapers available upon request, and include the source and calculation of key assumptions such as mitigation effectiveness, cost estimates, and other inputs.
- Consumers should provide an estimate of the impact that prior year's expenditures have made to reduce risk on the system. Given the substantial ratepayer expenditures each year on the gas system to improve safety, the Company should describe what has been achieved to date and how much risk is left on the system relative to five years ago, ten years ago, etc.? If Consumers has prioritized the highest risk assets each year, I would expect diminishing returns for risk reduction. This information can only be ascertained with historical analysis of risk reduction achieved to date.

- The Commission should cap additions to plant in service in the projected test year at no more than 2024 investment levels, as illustrated in Table 1.

Furthermore, the Commission should require Consumers to implement probabilistic risk models for EIRP and Vintage Service Program ("VSR") before spending at levels that increase additions to plant in service above 2024 levels. (See Table 8)

## III. ENERGY TRANSITION

**Q Could you please describe what you mean by the term "energy transition"?**

**A** The "energy transition" refers to the economy-wide transition to reduce GHG emissions by 80 percent or more by 2050 by moving away from an energy system of fossil fuel resources and toward an energy system of renewable and zero-carbon resources. The energy transition is underway in several jurisdictions across the United States as state agencies, public utility commissions, and utilities take action to support the achievement of the state's GHG emission reduction objectives.

**Q Are other jurisdictions taking actions to address the energy transition?**

**A** Many other jurisdictions are formally addressing issues related to the future of the natural gas system in a regulated context. For a detailed description of the future of gas dockets in 12 other jurisdictions including Massachusetts, New York, Maryland, the District of Columbia, Minnesota, Illinois, Colorado, Oregon, and California, refer to Exhibit MEC-15.

**Q Please summarize the major implications of the energy transition for gas utilities based on experience in other jurisdictions.**

**A** As demonstrated by the regulatory proceedings in numerous other jurisdictions, utility commissions are increasingly recognizing that business-as-usual

approaches to managing the gas system cannot continue if states are to achieve their emission reduction targets and maintain affordable rates. The major implications of the energy transition for gas utilities are:

- The future of gas consumption and gas utility asset utilization will not look like the past or present. Energy delivered by the gas system will fall substantially, and the building sector share of gas consumption will fall (Massachusetts, New York, Maryland).

- Business-as-usual approaches to accelerated leak-prone pipe replacement are not justified. Capital investments should not be made until they are shown to be superior to alternatives that incorporate repair, retirement, or NPAs such as efficiency and electrification (Massachusetts, New York, Maryland, Illinois). In addition, regulators are requiring higher levels of analysis to justify gas plans (New York) and more extensive reporting to justify gas capital investments (Illinois, Massachusetts, Colorado).

- The recovery of invested capital over a smaller volume of sales will mean higher gas distribution rates and increased competition from electricity. The extent of these gas rate increases can be reduced by changes to the utility's approach to capital investment, repairs, retirement, and depreciation (Massachusetts, New York).

- Utilities have a responsibility to undertake prudent planning and investment actions to adapt to the energy transition, taking into account the timeframe of that transition and how it relates to the lifetime of gas assets. Failure to

make prudent capital decisions increases stranded-asset risk, which may be borne by customers and/or investors (Massachusetts, Maryland, Colorado).

**Q Why is the energy transition relevant for this case?**

**A** As jurisdictions have started to plan for the energy transition and to model pathways to achieve net-zero emissions, available analyses have made clear that the transition requires broad reductions in gas consumption (see Exhibit MEC-15 for a discussion of pathways analysis conducted in different jurisdictions) to meet emission reduction targets. The transition requires a reduction in the amount of fuel the gas utilities deliver to customers, and this will ultimately be reflected in changes in the Company's rates and the Company's overall competitive position compared to alternatives. The transition will impact the need to build out, repair and replace, depreciate, and generally plan and invest in the gas system, with fewer customers to shoulder this risk. Decision-making related to infrastructure investments must account for the energy transition. Gas distribution utilities such as the Company get their revenue from delivering gas to customers and recovering both the costs of the gas commodity and the costs of maintaining the extensive pipeline network used to transport it. Utilities have the opportunity to earn a fair return on prudent investments in assets that are used and useful.

As the energy transition progresses and gas sales decline, some gas utility assets will no longer provide service or will not be used and useful. These assets will therefore need to be removed from the rate base. That removal turns those investments into "stranded assets." If the constructed stranded assets are not fully depreciated, the Company's remaining customers or investors will bear the risk of

those stranded costs. A rate case such as this one is where the prudence of a utility's actions can be evaluated and its rates adjusted to account for the cost of capital, for changes in the assets which are used and useful, and for their useful lives. The energy transition impacts these factors and thus is relevant to this case.

**Q What are Michigan's emission reduction policies?**

**A** Executive Directive No. 2020-10, signed by Governor Whitmer in September 2020, establishes a state-wide goal of achieving a 28 percent reduction in GHG emissions below 1999 levels by 2025, and reaching carbon-neutrality no later than 2050.[1] To achieve these reductions, the Governor then ordered the creation of the Michigan Healthy Climate Plan in September 2020. The plan includes a roadmap to a 52 percent GHG emissions reduction in space heating for Michigan buildings. The plan elaborates further with respect to natural gas: "To complement immediate policy actions, the Plan recommends the state undertake a pathway analysis to assess options to achieve carbon neutrality from natural gas production, transmission, distribution, compression, storage, and end uses in a least-cost manner. This analysis should consider a full range of options for decarbonizing natural gas end uses, including energy efficiency, electrification, fuel switching to renewable natural gas and hydrogen, and other potential opportunities."[2]

[1] Governor Gretchen Whitmer, Executive Directive No. 2022-10, September 23, 2020, available at: https://content.govdelivery.com/attachments/MIEOG/2020/09/23/file_attachments/1553296/ED%202020-10%20Carbon_Neutral_Goal.pdf.

[2] Michigan Healthy Climate Plan page 43.

**Q Do the natural gas utilities in Michigan have a role to play in meeting the state's GHG emission targets?**

A Yes, due to the reliance on natural gas for heating. Three-quarters of Michigan residents rely on natural gas for heating,[3] and in 2023 Michigan had the fourth highest natural gas consumption in residential and commercial sectors of any state in the United States.[4] According to the 2024 Michigan Healthy Climate Plan, the 'built environment' (which includes home and business heating) accounted for 16 percent of statewide GHG emissions with industry consumption accounting for another 19 percent in 2021.[5]

## IV. NATIONAL GAS DELIVERY PLAN AND CONSUMERS' CLIMATE TARGETS

**Q Please describe the Natural Gas Delivery Plan and how the plan addresses Michigan's GHG emission reduction objectives.**

A The Natural Gas Delivery Plan ("NGDP") presents the planned investments in natural gas infrastructure for the next 10 years. The framework for the investment plan considers the safety and reliability of gas supply and also factors in the changes needed to meet pipeline safety regulatory requirements.

The NGDP also includes the response of the Company to the decarbonization goals of Michigan. It includes a "strategic framework in response to the decarbonization

[3] U.S. Energy Information Administration (EIA), Michigan State Energy Profile, updated October 17, 2024, available at: https://www.eia.gov/state/print.php?sid=mi#51.

[4] EIA, Natural Gas Consumption by End Use, released January 31, 2025, available at: https://www.eia.gov/dnav/ng/ng_cons_sum_a_EPG0_vrs_mmcf_a.htm.

[5] Michigan Department of Environment, Great Lakes, and Energy (EGLE), Michigan Healthy Climate Plan: 2024 Report, December 2024, page 26, available at: https://www.michigan.gov/egle/-/media/Project/Websites/egle/Documents/Reports/OCE/MHCP-2024-Report.pdf.

goals of the company's natural gas customers and future carbon policy relevant to the utility."[6] The NGDP includes a discussion of its commitment to "reducing greenhouse gas emissions across its systems associated with the energy consumption of its customers."[7] The Company also mentions supporting Michigan's MI Healthy Climate Plan with its goal to "achieve net zero greenhouse gas emissions from the entire natural gas production and delivery system, including customers and suppliers, by 2050."[8]

**Q Does the Company have any GHG emission reduction goals?**

**A** The Company has established Scope 1 and Scope 3 targets.[9]

The Company established a goal to achieve net-zero Scope 1 methane emissions by 2030. The Company plans to achieve 80 percent of this reduction through near-term measures to reduce methane leaks from the system. This includes actions such as the reduction of distribution main and service leaks by replacing vintage pipe, reducing storage wellhead component leaks, and implementing compression blowdown venting procedures and transmission blowdown procedures. The balance of 20 percent is expected to be met through the procurement of carbon credits potentially through RNG.[10]

[6] Direct Testimony of Company Witness Neal P. Dreisig, page 3 at 6.

[7] Dreisig Testimony, page 5 at 14.

[8] Ex A-42, Natural Gas Delivery Plan (NGDP), page 77.

[9] Scope 1 emissions are those directly resulting from the Company's operations. This involves the reduction of fugitive methane and carbon emissions from the gas system. Scope 3 emissions are produced upstream and downstream of the Company; they include emissions that result from customers' consumption of gas purchased from Consumers.

[10] NGDP, page 78.

It also has a goal to reduce Scope 3 emissions by 20 percent by 2030 and to achieve net-zero carbon emissions by 2050. The Company clarifies that this "include[s] all emissions traced to natural gas purchases and activities by customers and suppliers, like those associated with burning natural gas to heat homes and businesses."[11] The Company's goal is to achieve the 20 percent reduction by 2030 through Energy Waste Reduction (EWR or energy efficiency), RNG, carbon offsets and other new emerging decarbonization technologies such as hydrogen, clean synthetic fuels, electrification, and carbon capture.

While the Company highlights the voluntary program allowing customers to offset carbon emissions through RNG—noting that it would contribute to the state's emission reduction targets—the Company admits that "[a]fter inception in April 2024, no customers have been enrolled,"[12] and states that the program is expected to be operational in late 2025. This raises questions about the efficacy of this program in contributing to the achievement of the Company's GHG emission reduction goals.

**Q Do you have any concerns that the Company does not have a more detailed decarbonization plan?**

**A** Yes. The Company has identified potential pathways to meet net-zero emissions by 2050. However, the Company has not provided any concrete plan to meet its Scope 3 targets, neither for 2030 nor for 2050. Despite findings from the state-wide decarbonization pathways analysis that support hybrid electric and gas

[11] NGDP, page 79.

[12] Discovery Response MNSC-CE-0034

heating,[13] the Company has stated that it "does not have current plans to deploy or support hybrid heating through 2030 and 2050."[14] The Company has less than five years to achieve the 20 percent reduction in Scope 3 emissions and has only presented a list of actions and a waterfall chart;[15] it has not presented a more detailed execution plan that includes actual tasks that must be completed to achieve these lofty goals.

**Q Do you have any concerns about the inconsistency between the Company's Scope 3 net-zero targets and the continued investment in natural gas infrastructure?**

A Yes. In the NGDP, the Company set an interim goal to help its customers achieve a 20 percent reduction in Scope 3 emissions by 2030. They also have a goal of net-zero emissions on or before 2050. The Company recognizes the immensity of the task, stating that "[r]eaching 'net zero' will require Consumers Energy to balance many diverse emission reduction opportunities with safe, reliable, and affordable energy delivery."[16] Included in the list of items that will support the achievement of this goal are EWR or energy efficiency programs and electrification, which suggest a reduction or elimination of the use of natural gas.

[13] According to the Company, hybrid heating "combines the heat content of natural gas with the efficiency of a heat pump. In this context, heat pumps would be used as much as possible; however, during the coldest winter months, natural gas furnaces would still be used to mitigate winter peak electric load." (NGDP, p. 82)

[14] Ex MEC-3, Discovery Response MNSC-CE-0039. Witness Napoleon sponsors Ex MEC-3.

[15] See Figure 40 on page 80 of the NGDP.

[16] NGDP, page 79.

As discussed in the next section, the Company's emissions reduction targets coexist with contradicting plans for continued significant and elevated levels of investment in natural gas infrastructure. For one, Consumers is expecting continued customer growth through at least 2035, despite a historically declining number of new connections (please refer to the testimony of my colleague, Alice Napoleon, for more details on gas demand).[17] The Company is also planning to replace 1,760 miles of vintage, standard pressure, and Transmission Operated by Distribution pipe over the next 10 years with no plans to conduct leak repair or consider NPAs for serving demand in lieu of replacement.[18]

**Q Why is this a concern?**

**A** From 2026 to 2035, Consumers is proposing long-lived infrastructure investments that will be paid for by its customers for decades. This proposal is inconsistent with the Company's Scope 3 emission reduction targets. The Company identifies several technologies that would contribute to meeting its Scope 3 objectives. The EWR/energy efficiency programs and increased electrification, in particular, should contribute towards a significant reduction in gas throughput and a reduction in gas customers. Thus, there is a risk that these new infrastructure investments will become stranded assets.

[17] NGDP, page 60.

[18] NGDP, page 51.

**Q In the NGDP, what are the long-term factors that drive the future of the natural gas business?**

A The Company identified four factors: safety, increasing regulation, changing supply and demand patterns, and an environmental focus.[19] The last factor has long-term implications. The Company elaborates, "[t]he impact of natural gas use on climate change through carbon emissions and methane emissions is becoming a focal point of environmentally conscious customers, regulators and other stakeholders as coal-based emissions from electric generation continue a downward trend."[20]

**Q Does the Company consider the energy transition in its gas planning, as presented in the NGDP?**

A The Company discusses its Scope 1 and Scope 3 net-zero targets and the potential technologies that can be used to meet these targets. It also includes a section in its NGDP discussing the results of the decarbonization modeling undertaken in 2021. However, there is no evidence that the Company considered these when developing the near-term or long-term capital plan for the distribution system.

In contrast to discussions about the energy transition and the changing energy environment in which the Company will be operating, Consumers' gas planning seems to assume the future will be the same as the past, with no departure from status quo. The NGDP includes a section with a 10-year focus on distribution assets, where the priority is to "[r]educe system risk and methane emissions while

[19] NGDP, page 11.

[20] NGDP, page 11.

addressing system reliability and capacity. This will be accomplished by addressing aging or vintage infrastructure that is closest to the customers" and to "[r]emediate vintage distribution main, standard pressure main, and vintage services to meet 2035 completion date."[21]

The planned investments in the distribution system are an extension of and completion of previously identified plans to replace pipe. The Company has not provided any indication that it considered other options, such as pipe repair or NPAs, that could be more suitable for a changing environment.

## V. OVERVIEW OF CONSUMER'S MAJOR INFRASTRUCTURE INVESTMENTS AND NATURAL GAS DELIVERY PLAN

**Q Please describe how the natural gas infrastructure investments were determined in the NGDP.**

**A** A significant amount of investment in the distribution system is for the replacement of pipelines of vintage materials. The investments also include expanded monitoring though advanced leak detection methodologies and upgrading the remote data monitoring system.

The Company is planning to complete the vintage pipe replacement programs by 2035, claiming that it balances safety, reliability, and affordability. Distribution programs aimed at replacing and expanding the distribution system make up almost 60 percent of Consumer's cumulative projected investments through 2034.[22]

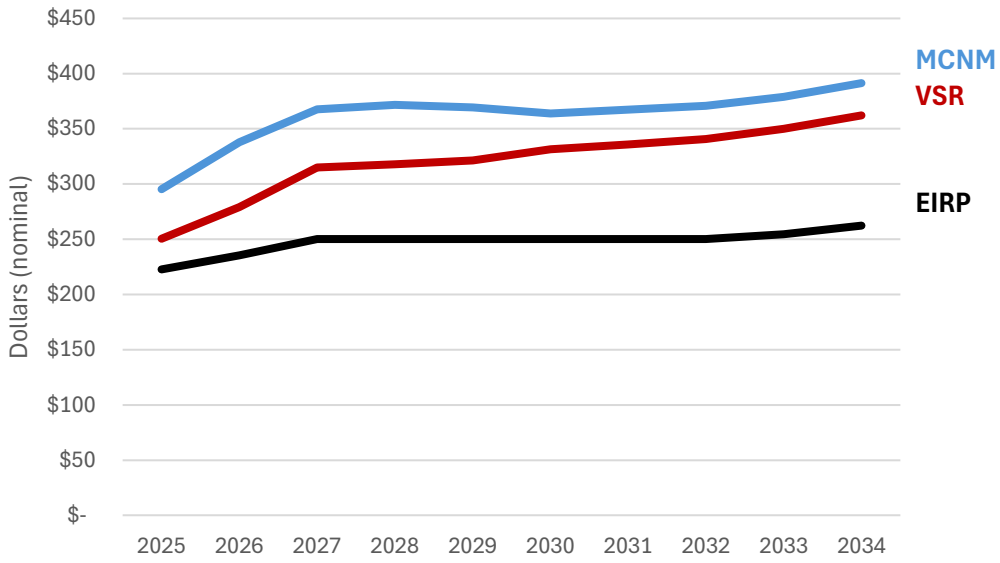
[21] NGDP, page 47.

[22] Discovery Response MNSC-CE-0007_Dreisig_ATT_1.

**Q Please characterize Consumers' natural gas infrastructure investments.**

A Three major pipe replacement programs within the distribution category include the EIRP, VSR, and Material Conditioned Non-Modeled Program (MCNM). The Company is on track to spend $3.6 billion in the next decade on the EIRP, VSR, and MCNM programs alone (see Figure 1).[23]

Figure 1. Distribution replacement program forecasted investment




*Source: MNSC-CE-0007_Dreisig_ATT_1.*

*Note: values are stacked to show cumulative program investment.*

[23] Discovery Response MNSC-CE-0007_Dreisig_ATT_1.

**i. Enhanced Infrastructure Replacement Program**

**Q Please characterize Consumer's Enhanced Infrastructure Replacement Program.**

A Launched in 2012, the EIRP replaces distribution pipes made of vintage, leak-prone materials. The EIRP is the Company's largest individual capital program, accounting for a fifth of cumulative projected investments through 2034.[24] In addition to replacing vintage pipes (defined as pipes made of cast iron, bare steel, threaded and coupled steel, and wrought iron),[25] Consumers intends to replace all low pressure pipe through the EIRP with the goal of eliminating its entire standard pressure system.[26] As of February 2024, there were 1,726 miles of vintage and standard pressure pipe slated for replacement under the EIRP.[27] The Company prioritizes segments of pipe using the Distribution Risk Analysis Model (DRAM).[28] Pipe repair is not part of the EIRP.[29]

**Q Please describe historical EIRP activities.**

A Refer to Table 1 showing historical miles of pipe replaced and capital expenditures under the EIRP since 2017. Since the start of the program in 2012, Consumer's has spent $1.6 billion on pipe removal and installation, in that time replacing roughly 980 miles of transmission and distribution pipe.[30] From 2012 to 2022,

[24] Discovery Response MNSC-CE-0007_Dreisig_ATT_1

[25] NGDP, page 48.

[26] NGDP, page 49.

[27] NGDP, page 51.

[28] Direct Testimony of Company Witness Kristine A. Pascarello, page 68 at 23.

[29] Discovery Response MNSC-CE-0579.

[30] Discovery Response MNSC-CE-0042_Pascarello_Attachment_1 through 12.

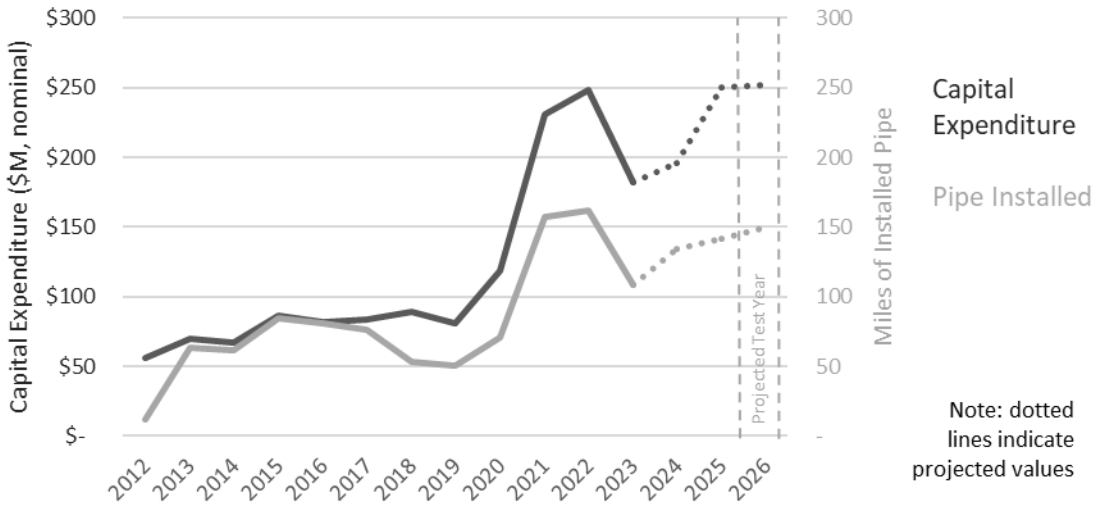
annual capital expenditures more than tripled; spending fell slightly in 2023, but Consumers' projected expenditures for 2025 and 2026 return to the same elevated levels from 2022 (see Figure 2).

**Table 1. EIRP Historical Pipe Replacement (nominal dollars)**

| | 2017 | 2018 | 2019 | 2020 | 2021 | 2022 | 2023 |
|---|---|---|---|---|---|---|---|
| **Pipe Retired (miles)** | 78.30 | 50.86 | 45.83 | 71.66 | 134.61 | 130.34 | 131.16 |
| **Pipe Installed (miles)** | 76.67 | 52.86 | 50.75 | 71.24 | 157.22 | 162.11 | 108.94 |
| **Capital Expenditure ($000)** | $83,705 | $88,821 | $81,028 | $118,551 | $230,723 | $248,149 | $181,927 |
| **Unit Cost ($000/mile installed)** | $1,092 | $1,680 | $1,596 | $1,664 | $1,468 | $1,531 | $1,670 |

*Source: MNSC-CE-0042_Pascarello_Attachment_1 through 12.*

**Figure 2. Historical and Projected EIRP Expenditure and Pipe Installation**




*Source: MNSC-CE-0042_Pascarello_Attachment_1 through 12.*

**Q What are Consumers' proposed investments for the EIRP?**

**A** Consumers is proposing to spend $697.5 million over 3 years (2024-2026) to retire 406 miles of old pipe and install 426.9 miles of new pipe through the EIRP.[31] Notably, the test year values show an almost 30% increase from $195.6 million in 2024 to a proposed $251.4 million in the test year,[32] noting that the amount in the test year "supports the annual installed mileage required to ensure program completion by 2035."[33]

**Table 2. EIRP projected pipe replacement (nominal dollars)**

| | 2024 | 2025 | 2026 | Total |
|---|---|---|---|---|
| **Pipe Installed (miles)** | 134.60 | 142.00 | 150.30 | 426.90 |
| **Capital Expenditure ($000)** | $195,587 | $250,300 | $251,600 | $697,487 |
| **Unit Cost ($000/mile installed)** | $1,453 | $1,763 | $1,674 | $1,634 |

*Source: Exhibit A-84 (KAP-6).*

### ii. Vintage Service Replacement Program

**Q Please characterize Consumer's Vintage Service Replacement program.**

**A** Beginning in 2017, the VSR program eliminates services made of vintage materials such as copper or bare steel, and services for which the material is unknown.[34] Within this program, service replacements fall into one of three groups: In-Grid VSRs, Proactive-in-Grid VSRs, and Proactive Out-of-Grid VSRs.

[31] Pascarello Testimony, page 49, Table 7; NGDP page 51.

[32] Pascarello Testimony, page 47 at 26.

[33] Pascarello Testimony, page 48 at 3.

[34] Pascarello Testimony, page 66 at 19.

- In-Grid VSRs are vintage services attached to vintage mains that are being replaced within an EIRP project. The cost of these service replacements fall under the EIRP.[35]

- Proactive In-Grid VSRs are vintage services attached to non-vintage mains within the footprint of an EIRP project. The cost of these service replacements falls under the VSR program.[36]

- Proactive Out-of-Grid VSRs are vintage services located outside of an EIRP project; project costs fall under the VSR program.[37]

Vintage services might also be replaced outside of the VSR program, such as services replaced through the Material Condition Non-Modeled program, and others.[38]

Vintage services are currently prioritized based on a manual analysis process that considers factors such as leak rate, material age, and soil conditions; although the Company states that in 2025 it plans to transition to using the Distribution Risk Analysis Model (DRAM) which is currently used to analyze distribution pipes.[39]

**Q Please describe historical VSR activities.**

**A** Refer to Table 3 showing historical VSR replacements and expenditures. The table excludes service replacements carried out through the EIRP and through other

[35] Pascarello Testimony, page 69 at 16.

[36] Pascarello Testimony, page 69 at 20.

[37] Pascarello Testimony, page 69 at 28.

[38] Pascarello Testimony, page 68 at 13.

[39] Pascarello Testimony, page 69 at 23.

programs, it only includes service replacements associated with VSR expenditure. The VSR program represents about half of the Company's total service replacements from 2017 to 2023.[40]

**Table 3. VSR historical service replacements (nominal dollars)**

| | 2017 | 2018 | 2019 | 2020 | 2021 | 2022 | 2023 |
|---|---|---|---|---|---|---|---|
| **Proactive In-Grid and Out-of-Grid VSRs** | 6,307 | 9,381 | 5,571 | 5,456 | 5,056 | 2,176 | 1,228 |
| **VSR Program Spend ($000)** | $33,564 | $56,634 | $40,443 | $42,818 | $32,955 | $17,165 | $11,354 |
| **VSR Unit Costs** | $5,322 | $6,037 | $7,260 | $7,848 | $6,518 | $7,888 | $9,246 |

**Q What are Consumers' proposed investments for the VSR program?**

**A** Table 4 shows the Company's projected VSR replacements and expenditures through 2026.

**Table 4. VSR projected service replacements (nominal dollars)**

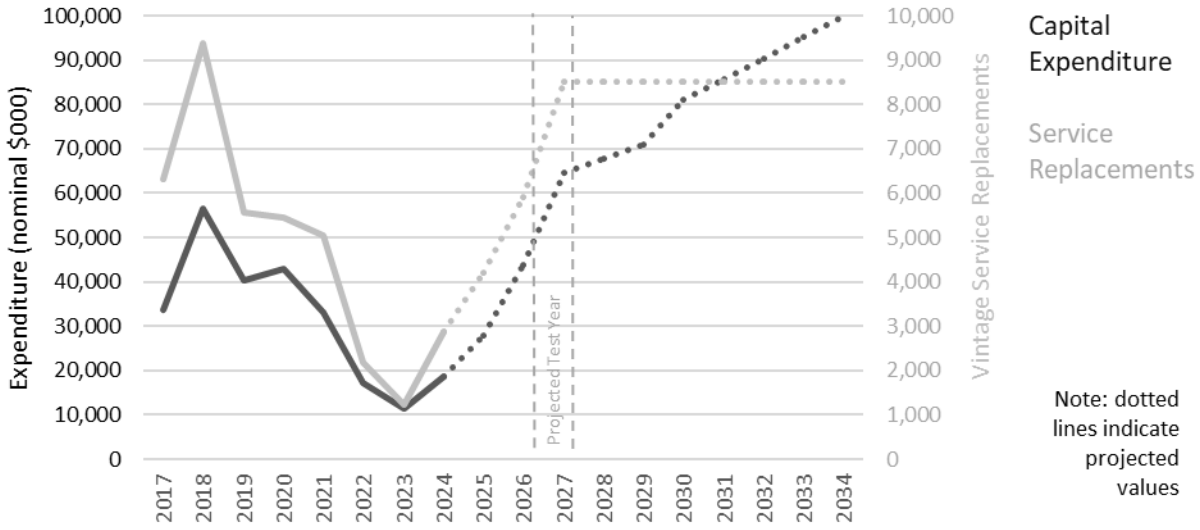
| | 2024 | 2025 | 2026 | Total |
|---|---|---|---|---|
| **Proactive In-Grid and Out-of-Grid VSRs** | 2,875 | 4,194 | 5,913 | 12,982 |
| **VSR Program Spend ($000)** | $18,666 | $27,978 | $43,689 | $90,333 |
| **VSR Unit Costs ($)** | $6,493 | $6,671 | $7,389 | $6,851 |

*Source: Pascarello Testimony, page 71.*

[40] Pascarello Testimony, page 71 Table 9; MNSC-CE-0040_Pascarello_Attachment_1.

Consumers' projects an increased number of vintage service replacements in 2024, 2025, and 2026, and through 2035.[41] The VSR program spend increases 128 percent from $18.6 million in 2024 to a projected $42.5 million for the test year.[42]

**Figure 3. VSR service replacements**




*Source: Pascarello Testimony, page 71; MNSC-CE-0040_Pascarello_Attachment_1; MNSC-CE-0007_Dreisig_ATT_1.*

### iii. Material Condition Non-Modeled Program

**Q Please characterize Consumers' Material Condition Non-Modeled program.**

**A** This program replaces distribution main not covered by the EIRP. Under this program, pipes might be replaced due to emergent safety concerns, active gas leaks, compliance with regulation, and Company-initiated projects of certain

[41] Pascarello Testimony, page 71 Table 9; MNSC-CE-0040_Pascarello_Attachment_1

[42] Pascarello Testimony, page 71 at 1.

assets "which may not rank as highly in the Company's risk modeling but whose replacements offer operational advantages to the Company and customers."[43]

**Q How does the MCNM program differ from the EIRP?**

**A** Both the EIRP and MCNM program address risk-related needs of the system. Witness Pascarello explains that, as EIRP planning increasingly happens further out, the MCNM program gives the Company flexibility to address emergent needs of the deteriorating system as they arise.[44]

**Q Please describe historical MCNM activities.**

**A** Table 5 shows the Company's historical expenditure, replaced pipe, and unit costs under the MCNM program. As stated in discovery, "There are zero miles of pipe repaired in this program."[45]

**Table 5. MCNM historical replacements and expenditures (nominal dollars)**

| | 2020 | 2021 | 2022 | 2023 | 2024 |
|---|---|---|---|---|---|
| **Pipe Replacement (miles)** | 9.37 | 19.8 | 12.9 | 10 | 11.8 |
| **Capital Expenditure ($000)** | $36,892 | $50,126 | $42,358 | $38,516 | $39,443 |
| **Unit Cost ($000/mile replaced)** | $3,937 | $2,532 | $3,284 | $3,852 | $3,343 |

*Source: MNSC-CE-0578*

[43] Pascarello Testimony, page 50 at 24.

[44] Pascarello Testimony, page 52 at 6.

[45] Discovery Response MNSC-CE-0578.

**Q What are Consumers' proposed investments for the MCNM program?**

**A** Consumers is proposing to spend over $130 million on MCNM projects through 2026.[46] This includes (but is not limited to) three Company-initiated projects: replacing 6 miles of wrought iron pipe (with plans to replace the entire remaining 12 miles of the wrought iron system over the next four years), a $38 million Maximum Allowable Operating Pressure (MAOP) compliance project on Line 1010, and a high pressure waterway crossing.[47] The MCNM program spend increases 47 percent from $38.3 million in 2024 to a projected $56.2 million for the test year.[48]

**Table 6. MCNM projected expenditure (nominal dollars)**

| | 2024 | 2025 | 2026 | Total |
|---|---|---|---|---|
| **Capital Expenditure ($000)** | $38,256 | $42,628 | $56,206 | $138,277 |

*Source: Exhibit A-82 (KAP-4), pages 1- 2;*

**Q What can you say about the increase in gas infrastructure investment?**

**A** The test year capital expenditures for five programs is $385.7 million, a 45 percent increase from $266.3 million in 2023 and 35 percent increase from $285.7 million in 2024.[49] The test year totals are a snapshot of a sustained high level of capital investment proposed by the Company (see Figure 4), leading to an increasing rate

[46] Exhibit A-82 (KAP-4), page 2.

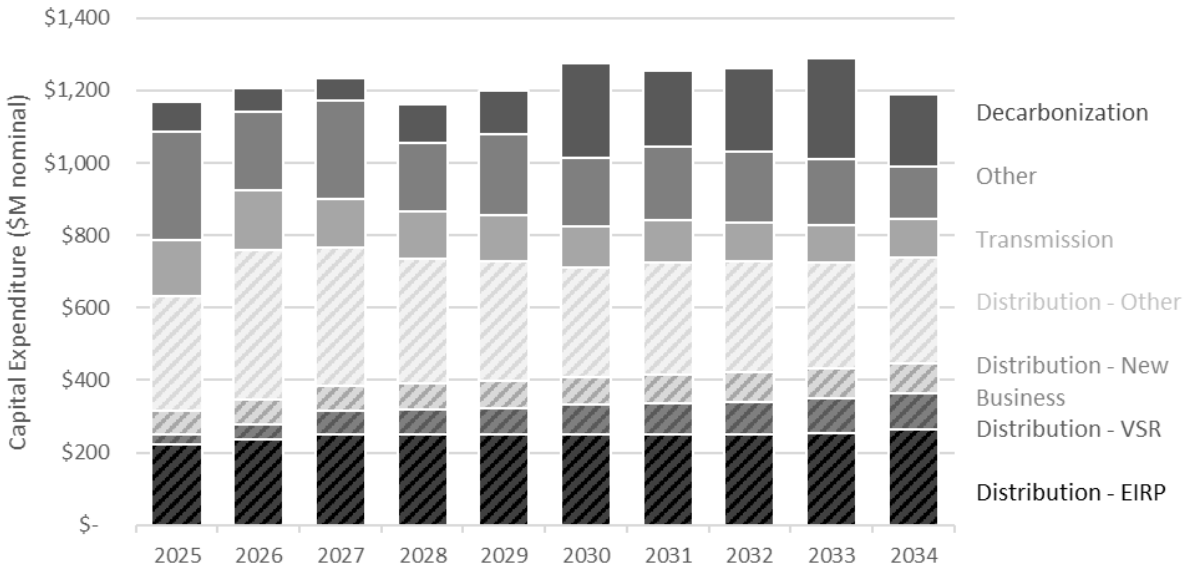
[47] Pascarello Testimony, page 56 at 15.

[48] Exhibit A-82 (KAP-4), page 1.

[49] Pascarello testimony, page 34 at 16.

base. This level of spending, combined with sales the Company itself projects will decline and are likely to decline more than the Company projects.[50]

**Figure 4. Projected capital investment by program**




*Source: MNSC-CE-0007_Dreisig_ATT_1.*

## VI. RISK MODELING AND COST-EFFECTIVENESS TO MAXIMIZE SAFETY IMPACTS OF RATEPAYER EXPENDITURES

### i. Overview of Risk Modeling and Cost-Effectiveness

**Q How do you define cost-effectiveness in relation to safety-related programs?**

A In this context, cost-effectiveness analysis examines the level of risk reduction expected from alternative measures in comparison with the cost to deploy these alternatives. This type of analysis allows the utility and stakeholders to compare various mitigations against each other, such as replacement versus pipe lining,

[50] See Direct Testimony of Alice Napoleon.

from both a safety impact and cost perspective, and can support evaluations regarding prudence.

**Q How can utilities model the risk of its gas system?**

**A** A probabilistic risk model utilizes historical data and subject matter expertise to estimate the likelihood of failure and consequence of failure for specific areas or pipeline segments. The multiplication of likelihood and consequence is the risk. Consumers acknowledges that probabilistic models "show great promise as a tool in more accurately assessing pipeline risk," as compared to relative risk models.[51]

**Q How can a utility calculate the cost-effectiveness of various safety investments?**

**A** Cost-effectiveness, or risk spend efficiency (RSE), is calculated by dividing risk reduction of each mitigation alternative by cost. Ideally, for capital projects, costs should entail the full revenue requirement of an investment over the full depreciation life of the asset, discounted appropriately.[52] Risk reduction is calculated as the level of risk multiplied by mitigation effectiveness (percent reduction in likelihood and/or consequence), discounted appropriately in each year. Mitigation effectiveness can be determined based on historical data and/or subject matter expertise.

*RSE = Risk Reduction (Risk x Mitigation Effectiveness) / Cost*

[51] Direct Testimony of Company Witness Michael P. Griffin, p. 17 at 22.

[52] This allows for the comparison of O&M and capital mitigations. However, if the only mitigations available are capital investments with similar depreciation lives, the calculation of full revenue requirements is less important.

**Q What is the value of risk modeling and cost-effectiveness analyses?**

A Risk modeling and cost-effectiveness calculations allow stakeholders to examine the level of risk reduction expected from Consumers' proposed remediations, the cost to achieve this, and an ability to assess alternatives that could better maximize risk reduction and minimize costs. These analyses provide transparency and insight into tradeoffs between risk reduction and affordability.

This type of transparency is currently lacking in Consumers' application. The inability to assess tradeoffs between safety impacts and affordability means the Commission must rely on relatively vague utility proclamations without data-driven, analytical support that Consumers' proposals are in the ratepayer interest. In the context of moving gas system planning away from business-as-usual to a more forward-looking approach, risk analysis is an important component to help reduce unnecessary or ineffective expenditures while still investing where necessary to ensure safe, reliable gas service.

**Q What is the relationship between risk modeling, cost-effectiveness, and the energy transition?**

A As stated above, in the face of the energy transition, gas utility actions that avoid, reduce, or delay irreversible investments have particular value. Risk modeling and the examination of cost-effectiveness gives utilities, stakeholders, and regulators the tools to maximize risk reduction and minimize ratepayer spending on irreversible and long-lived investments. This helps to further the energy transition without compromising customer safety (and even making the system safer through a more granular understanding of risk). Quantitative estimates of risk reduction,

cost, and cost-effectiveness of utility proposals and alternatives provide a rigorous way to explore tradeoffs between safety and affordability. The Company's transmission asset risk model illustrates the importance of risk modeling for maximizing risk reduction and minimizing costs. For example, it shows that 80 percent of the current risk on the transmission system is contained within just over 9 percent of total transmission miles (208 miles).[53] This information can allow the utility and its regulator to properly target investment towards the highest risk assets.

**Q Should all utility programs calculate cost-effectiveness metrics?**

**A** There is a distinction to be made between "compliance" programs that are mandated by a law or regulation, and therefore have little-to-no flexibility for what measures to employ to remediate safety issues, and expenditures where multiple alternatives can be assessed (i.e. are "discretionary"). However, I note that the lines between these categories of programs are often unclear, which is why it is important to assess the risk reduction and cost-effectiveness of all utility programs.

**Q Do you have any examples of utilities that use risk modeling and cost-effectiveness in their decision-making?**

**A** Washington Gas (WGL), the gas utility in the District of Columbia, states that it utilizes risk models and cost-effectiveness to optimize investment and prioritization decisions:

> Once the risk has been assessed for assets associated with each project, a parametric estimate of the cost for each project is

[53] Statistics derived from Discovery Response U21806-MNSC-CE-0080_Griffin_CONF_ATT_1_EB.

> produced. The Company then ranks projects to achieve the greatest reduction of overall risk per dollar invested. This basic prioritization may then be modified as appropriate to consider poor asset conditions observed directly by Company personnel, alignment with schedules for work compelled by others, and completion of work in-process.[54]

Furthermore, all California utilities must model risk to develop cost-effectiveness statistics for their gas inspection and investment programs. This framework was instituted in the wake of a 2010 pipeline failure in San Bruno, California, part of Pacific Gas and Electric's (PG&E) service territory.[55]

**Q Have risk modeling and cost-effectiveness calculations influenced how the California Public Utilities Commission ("CPUC")assesses utility expenditures?**

A Yes. In its decision on PG&E's test-year 2023 rate case, the CPUC reduced PG&E's proposed rate of 12 in-line inspection (ILI) upgrades per year to 4 per year, based on recommendations by an intervenor in that proceeding, The Utility Reform Network ("TURN").

> PG&E has not convincingly demonstrated that performing ILI upgrades at the rate of four segments per year would fail to meet the requirements of federal and state law and regulations, nor would it conflict with prior Commission decisions. Moreover, the lack of cost-effectiveness of ILI upgrades disfavors performing them at the pace requested by PG&E. TURN shows, for example, that the RSE [Risk Spend Efficiency] for PG&E's proposal is 0.08, ranking the ILI Program 171st out of 247 programs for which PG&E calculated an RSE. This translates to a benefit-cost ratio of only 0.0159, or a

[54] *Application of Washington Gas Light Company for Authority to Increase Existing Rates and Charges for Services*, Case No. 1180, Supplemental Direct Testimony of Kevin Murphy, November 4, 2024, p. 13.

[55] https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M325/K471/325471063.PDF; https://pstrust.org/map-of-major-incidents/sanbruno/.

> benefit of 1.6 cents of risk reduction for every dollar spent. Compared to the costs and benefits of the combined external corrosion direct assessment and stress corrosion direct assessment costs every seven years (discussed below), it is unreasonable for ratepayers to pay for more than four ILI upgrades per year.[56]

The type of analysis discussed in this decision is not possible with the information provided by Consumers in this case.

### ii. Consumers Use of Risk Modeling and Cost-Effectiveness

**Q Has Consumers developed probabilistic risk models to estimate the risk to customers of its assets?**

A Consumers developed a probabilistic risk model for transmission assets and Transmission Operated by Distribution assets. It is developing a model for storage wells which it expects to begin utilizing in 2025; the Company expects to develop a probabilistic distribution asset risk model by 2027.[57] The Company currently uses relative risk models for storage wells and distribution assets.[58]

Consumers acknowledges the importance of probabilistic risk modeling to accurately assess risk:

> In the last several years probabilistic models have been developed, and show great promise as a tool in more accurately assessing pipeline risk. The use of a model that is entirely data driven provides a more accurate representation of the risks associated with pipelines. This in turn will allow the Company to more precisely mitigate risks

[56] D. 23-11-069, Decision on Test Year 2023 General Rate Case for Pacific Gas and Electric Company, 11/17/23, p. 88.

[57] Discovery Response MNSC-CE-0080, part (a).

[58] Discovery Response MNSC-CE-0080, part (a).

associated with its transmission system to improve customer safety and reliability.[59]

Additionally, Consumers states "[Pipeline and Hazardous Materials Safety Administration] has identified the probabilistic risk model as a potential best practice for pipeline operators over other risk models."[60]

**Q What is your understanding of a relative risk model as compared with a probabilistic one?**

**A** A relative risk model ranks assets within an asset class (e.g. transmission pipe, distribution pipe, storage wells, etc.) based on certain characteristics (material, location, etc.) but does not calculate a quantitative risk score using likelihood of failure and consequence of failure. These models cannot examine cost-effectiveness of remediation alternatives, nor can the risk across asset types (e.g. distribution vs. transmission vs. storage wells) be compared against each other. By contrast, a probabilistic risk model calculates a quantitative risk score that can be used to understand the cost-effectiveness of alternative remediations and risk across different types of assets.

**Q Does Consumers utilize cost-effectiveness information to support its cost forecast and justify prior investment decisions?**

**A** In general, no. Consumers cannot calculate these statistics without a probabilistic risk model. Consumers does not have a probabilistic risk model for distribution

[59] Witness Griffin Testimony, page 17 at 22.

[60] Witness Griffin Testimony, page. 17 at 5.

system or asset classes such as storage wells. So for distribution-level assets it cannot justify investments based on cost-effectiveness.

For transmission-level assets, the Company states it *prioritizes* inspection by likelihood of failure and overall risk, as calculated by its probabilistic risk model of transmission assets.[61] Additionally, for certain programs, the Company states that it utilizes risk modeling results to prioritize selection of its projects. For example, the Asset Relocation Transmission Program prioritizes "[s]egments showing a higher overall risk reduction as a result of increased depth of cover [which] are graded as higher priority within the Asset Relocation Program." That said, the Company allows itself considerable flexibility to deviate from remediating the highest risk projects, stating "[p]rioritization may also be adjusted based on availability of transmission pipeline outages, continued coordination with local municipalities or governing authorities for civic-related work, and anticipated future replacement under another program (such as TED-I)."[62]

When asked whether it utilizes cost-effectiveness to determine what pipelines or mitigations to target during the rate case period, the Company responded:

> No, Consumers Energy does not perform cost-effectiveness or RSE metrics. The Pipeline Integrity program falls under [Pipeline and Hazardous Materials Safety Administration] requirements to perform on a reoccurring basis.[63]

[61] Witness Griffin Testimony, page. 14 at 10.

[62] Witness Griffin Testimony, page 9 at 2.

[63] Discovery Response MNSC-CE-0081.

**Q Can you provide an example of issues with specific safety programs?**

**A** As an example, Consumers provides regular reports detailing work accomplished in the EIRP, a major expense for gas ratepayers every year. In its reporting on the program, Consumers is obligated to provide the "risk ranking for all projects." However, ~~at least in the publicly available reports available to stakeholders, the Company rarely does this~~ while the Company provides numerical risk ranking values for distribution projects, it is not possible to discern whether Consumers prioritized projects appropriately based on risk ranking, nor whether some projects are "high risk" based on Consumers risk model results~~.~~ As stated above, it also does not examine the cost-effectiveness of alternatives to support its expenditures. Table 7 shows the first five reasons given by the Company for EIRP projects in 2023, demonstrating the lack of risk ranking and cost-effectiveness information provided in these reports.

**Table 7. Consumers' stated reason for selection of EIRP projects**

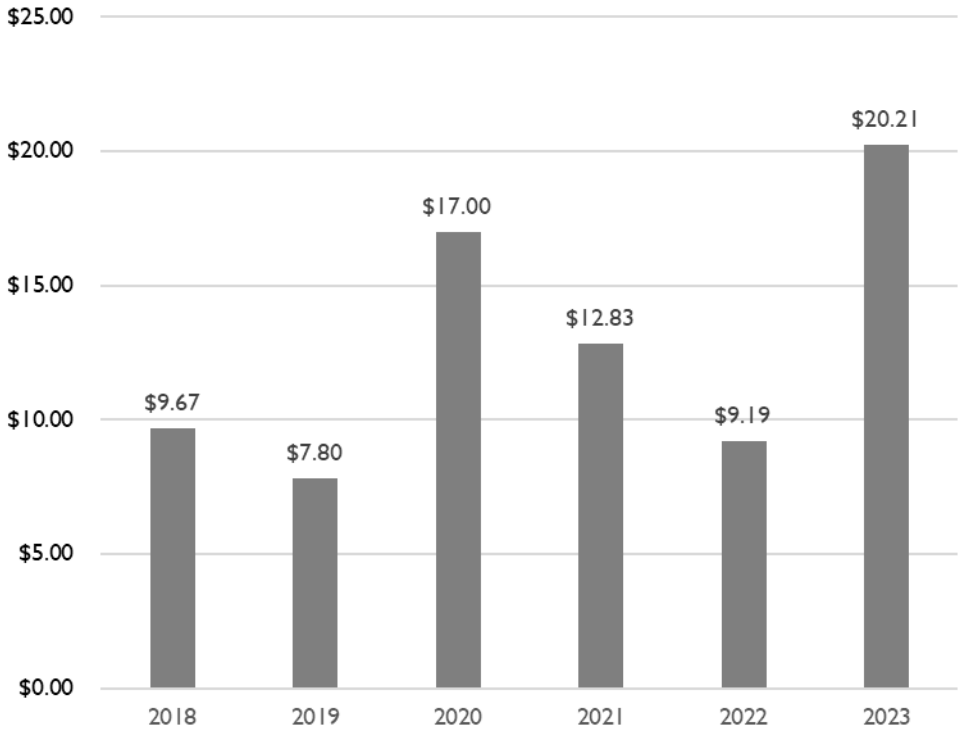
| Risk Rank / Selection Reason |
|---|
| 20" Line 100A, built in 1949, has reached the end of its useful life. Phase 1 of the Mid-Michigan project has replaced ~30 miles of 20" steel piping with new 36" steel piping from Chelsea to Williamston. |
| Install 20" PLD on 2700/600 to protect the MAOP difference |
| Removal of TDW hot tap tee on Line 2020 |
| Replace actuator on valve 605T12W and update to RCV |
| Site reaching the end of its design life. Project completed in conjunction with mid-Michigan pipeline project. Added modern filter/separator to enhance gas quality and protect downstream facilities and customers. |

*Source: U21806-MNSC-CE-0079_GRIFFIN_ATT_1_to_6, tab "2023 Att 8 Transmission."*

It is not my testimony that these, or other EIRP projects, were not necessary or prudent, as I have not conducted analysis at the project level. It is my testimony that the selection of projects under the EIRP program is not transparent from a risk reduction and cost-effectiveness perspective, which makes it impossible to assess the prudency of these investments.

A high-level analysis of the EIRP program's cost-effectiveness from 2018–2023 underscores why it is critical for cost-effectiveness to play a substantial role in the selection of projects. In Figure 5 below I calculated the dollars per leak remediated in each year. Leaks remediated in each year are therefore used as a proxy for reduced risk by that year's EIRP investments.

**Figure 5. Dollars per leak remediated 2018–2023 ($ million, nominal)**




*Source: 2018-2023 EIRP Reports, expenditures and leak remediated on the distribution system. Links to the reports provided in Consumers response to U21806-MNSC-CE-0079.*

First, I observe that this program is expensive, costing ratepayers $20 million *per leak* in 2023. Second, if Consumers EIRP program were targeted to remediate the most risk (as measured by leaks) at least cost, I would expect earlier years of program implementation to be much more cost-effective (lower expenditures per leak remediated) compared to later years (higher expenditures per leak remediated). While there is no clear pattern in Figure 5, the data is largely not consistent with this expectation, with the exception of a comparison of 2018 and 2023. However, work accomplished in 2022 was 18 percent *more* cost-effective than 2018, while 2020 and 2023 had similar cost-effectiveness results. Therefore, based on the data I reviewed, including the EIRP reports and the analysis above,

it is unlikely that the EIRP program has maximized safety impacts for the ratepayer dollars spent in each year.

### iii. Assessment and Recommendations Regarding Risk Modeling and Cost-Effectiveness

**Q What are your concerns with Consumers' use of risk modeling and cost-effectiveness statistics?**

A The Company does not have probabilistic risk models to calculate cost-effectiveness statistics for the distribution system or individual assets such as storage wells, though it is working on these models. In the current case, however, there is no way to tell whether the Company is performing cost-effective work that is in the interest of ratepayers, nor is it possible to even calculate cost-effectiveness of alternatives for a majority of forecast spending.[64]

While the Company states that cost-effectiveness is a "factor" in its decision-making, it has not provided evidence of this, and it is thus not possible to ascertain the extent to which cost-effectiveness influences project selection.[65] Indeed, the Company would not provide estimates of mitigation effectiveness (discussed above) for the various remediations it considered, so I cannot confirm that the Company even considers cost-effectiveness.[66] Additionally, it is unclear that the EIRP program has adequately prioritized cost-effectiveness and risk reduction.

[64] In 2025 and 2026, distribution-related expenditures comprise 54 percent and 63 percent of total expenditures, respectively, based on my review of U21806-MNSC-CE-0007_Dreisig_ATT_1.

[65] Discovery Response U21806-MNSC-CE-0285, part (a) says: "Cost effectiveness is factored into the remediation methodology selected for each individual project as well as complying with all applicable regulations and industry standards."

[66] Discovery Response U21806-MNSC-CE-0282.

Further, while the Company appears to understand the importance and necessity of risk modeling to prioritize its programs and investments, its use of models to examine the cost-effectiveness of remediations is extremely lacking. In sum, the Commission and stakeholders have very little information to assess whether Consumers' use of ratepayer funding is efficient and effective at reducing safety risk to customers.

Due to these shortcomings, there is a concerning lack of transparency and support for past and future spending. Is the Company's proposal the most efficient use of ratepayer funds? Is Consumers prioritizing the right types of inspections and remediations to cost-effectively maintain the safety of its system? Could NPAs more cost-effectively mitigate safety risks? These basic questions get at the heart of what expenditures should be deemed "just and reasonable" in this case. Based on my review of materials provided, neither I nor the Commission can satisfactorily answer these questions.

**Q What are your recommendations?**

**A** First, Consumers should provide on a regular basis and in its applications for ratepayer funding far greater transparency regarding the tradeoffs between safety and affordability. This includes, but may not be limited to:

- Reporting on transmission-level projects that demonstrates how Consumers utilizes cost-effectiveness, where applicable, to maximize safety impacts for the ratepayer dollars spent. Calculations and assumptions should be available to stakeholders upon request.

- EIRP reporting should include risk-ranking information (risk rank of asset remediated and total number of assets) and narrative descriptions regarding the use of risk-ranking driving remediation for a particular project.
- When probabilistic risk models are available for distribution assets starting in the next rate case, Consumers should:
    - Calculate and utilize total risk reduction and cost-effectiveness statistics as an important input into selecting appropriate projects and related remediations. Cost-effectiveness statistics and all inputs and assumptions should be made available to stakeholders upon request, including the ability to calculate risk reduction and cost-effectiveness for alternative projects and remediations.
    - Summarize in its EIRP reports remediations examined, cost-effectiveness of projects relative to alternatives, and explanations of why the Company's remediation was selected.

Second, future rate case applications should utilize probabilistic risk modeling and cost-effectiveness calculations to a much greater extent for all asset classes. This modeling should be made available upon request to stakeholders and the Commission, including the following:

- Unless Consumers can demonstrate it is not possible, it should develop probabilistic risk models for use in the next rate case for all asset classes (distribution, storage wells, etc.).

- For each project proposed in the test year, Consumers should calculate the risk reduction, cost, and cost-effectiveness (RSE) of its expenditures. All workpapers should be made available upon request and include the source and calculation of key assumptions such as mitigation effectiveness, cost estimates, and other inputs.

- Consumers should provide an estimate of the impact prior year's expenditures have made to reduce risk on the system. Given the substantial ratepayer expenditures each year on the gas system to improve safety, Consumers should explain what has been achieved to-date, and how much risk is left on the system relative to five years ago, ten years ago, etc. If Consumers has prioritized the highest risk assets each year, I would expect diminishing returns for risk reduction. This information can only be ascertained with historical analysis of risk reduction achieved to date.

- The Commission should cap additions to plant in service in the projected test year at no more than 2024 investment levels (see Table 8). Furthermore, the Commission should require Consumers to implement probabilistic risk models for EIRP and Vintage Service Program ("VSR") before spending at levels that increase additions to plant in service above 2024 levels.

**Table 8: Recommendations - Test Year**

| | | | | Recommendation: Capped at 2024 levels |
|---|---|---|---|---|
| | **2023** | **2024** | **Test Year** | **Test Year** |
| EIRP | $181,927 | $195,587 | $251,372 | **$195,587** |
| VSR | $11,354 | $18,666 | $42,513 | **$18,666** |
| MCNM | $38,516 | $38,256 | $56,206 | **$38,256** |

## VII. ALTERNATIVES TO PIPE REPLACEMENT AND PATHWAYS TO MEETING NET-ZERO EMISSIONS

**Q Is Consumers considering leak repair as an alternative to pipe replacement?**

**A** Consumers is not considering leak repair for any proposed projects.[67] The Company has stated that it does not consider pipe repair for the EIRP[68] or the MCNM program.[69]

The Company has already produced an example of what kind of analysis should be conducted when considering alternatives to pipe replacement. For example, the Company completed a cost and risk analysis for Line 1010 to compare the cost of pressure testing the existing pipe to test for MAOP compliance, with the cost of complete pipe replacement. While the Company decided to proceed with pipe replacement, the evaluation was conducted and made available to the public.[70]

[67] Discovery Response MNSC-CE-0578.

[68] Discovery Response MNSC-CE-0579.

[69] Discovery Response MNSC-CE-0578.

[70] Pascarello Testimony, page 56 at 23.

**Q What are NPAs and why are they relevant to the energy transition?**

**A** NPAs are solutions that meet customer energy needs and are alternative to traditional infrastructure investments. Examples of NPA portfolio components include electrification, energy efficiency, and other measures that reduce or eliminate customers' demand for natural gas. NPAs can be temporary solutions to defer infrastructure replacement or long-term solutions that allow utilities to decommission assets. The benefits of NPAs include emission reductions and associated health benefits, avoided costs from traditional infrastructure investments, and reduced risk of future stranded assets. When faced with uncertainty, companies can reduce risk by retaining optionality and avoiding potentially unnecessary capital investments. In the face of the energy transition, gas utility actions which avoid, reduce, or delay irreversible investments have particular value.

**Q Has the Company discussed implementing any NPAs?**

**A** The Company does not address NPAs in its application nor has it proposed any NPA projects in its capital investment plan. To date, the Company has only completed an initial screening criterion which identified Kalamazoo, Lansing, and Flint as "the top communities to investigate further for an initial feasibility data assessment"[71]

[71] Discovery Response MNSC-CE-0030.

**Q Consumers claims that affordability is a main objective of the NGPD. Are there other actions it can do to address affordability?**

**A** Consumers claims that affordability is one of the key objectives of the NGPD. However, in the planning for the gas infrastructure investment, there is no evidence that the Company evaluated alternatives such as leak repair or NPAs that could reduce the need for pipeline replacement and thus be a lower-cost alternative to continued gas investments.

**Q Is it reasonable or prudent for the Company to make investment decisions without evaluating alternatives, such as pipeline repair or NPAs?**

**A** No. By failing to evaluate alternatives, the Company runs a high risk of spending more money than is necessary to achieve the safe and reliable gas system that it is obligated to maintain and operate. Because the Company has provided no records of any cost-effectiveness or other evaluations conducted to determine the most appropriate investment, it is essentially asking for approval billions of dollars of capital investments without substantive justification that they were truly necessary.

**Q Does this complete your direct testimony?**

**A** Yes, it does.

MR. BZDOK: By stipulation with Consumers Energy as part of the mutual waiver of witnesses Snyder and deLeon, I would move to admit into evidence Exhibit MEC-69, which consists of discovery responses 9 -- sorry, MNSC-CE-0922 through 0926, not including the confidential attachment to 0925.

JUDGE VARCHETTI: All right. Are there any objections to the admission of Exhibit MEC-69 under the conditions described by Mr. Bzdok?

I am hearing none, so the exhibit is admitted.

MR. BZDOK: Thank you, Your Honor.

Finally, on behalf of MEC and Sierra Club, I would move to admit proposed Exhibit MEC-58, which was part of Mr. Dreisig's hearing exhibits folder. It is discovery response MNSC-CE-0771, and attachment 1 and attachment 4, pages 39 through 46. It was our intent to admit that exhibit during his exam, and we inadvertently omitted it.

JUDGE VARCHETTI: All right. Are there any objections, then, to admitting Exhibit MEC-58 and the two associated attachments as discussed by Mr. Bzdok?

I am hearing none, so the exhibit is admitted.

MR. BZDOK: Thank you, Your Honor.

That's it on behalf of MEC and Sierra Club.

JUDGE VARCHETTI: Thank you. And I believe that just leaves CUB and then Staff.

So, Ms. Hillyer, it looks like you were raising your hand. You can proceed.

MS. HILLYER: Thank you. Can you hear me, Your Honor?

JUDGE VARCHETTI: Yes, I can hear you.

MS. HILLYER: Okay. Apologies. I froze for a moment.

At this time, on behalf of the Citizens Utility Board of Michigan, I move to bind into the record the prefiled direct testimony of Rick Bunch, which consists of a cover page, a table of contents, and 27 pages of questions and answers, and I also move for the admission of Mr. Bunch's exhibits, which consist of Exhibits CUB-1 through CUB-6.

JUDGE VARCHETTI: All right. Are there any objections to the admission of Mr. Bunch's direct testimony or the associated exhibits?

Hearing none, then, the testimony is bound into the record, and the exhibits, associated exhibits, are admitted.

MS. HILLYER: Thank you, Your Honor.

(Direct Testimony bound in)

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

| | |
|---|---|
| In the matter of the application of **CONSUMERS ENERGY COMPANY** for authority to increase its rates for authority to increase its rates for the distribution of natural gas and for other relief. | U-21806 |

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**DIRECT TESTIMONY OF RICHARD J. BUNCH**

**ON BEHALF OF**

**CITIZENS UTILITY BOARD OF MICHIGAN**

**April 23, 2025**

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**DIRECT TESTIMONY OF RICHARD BUNCH FOR CUB**
**CASE NO. U-21806**

## I. INTRODUCTION & QUALIFICATIONS

**Q. Please state for the record your name, position, and business address.**

A. My name is Richard Bunch. I am a lead consultant at 5 Lakes Energy, LLC. My business address is 220 MAC Ave, Suite 220, Lansing, MI. I am also Executive Director of Michigan Municipal Association for Utility Issues (MI-MAUI), which has not intervened in this rate case.

**Q. On whose behalf is this testimony being offered?**

A. I am testifying on behalf of Citizens Utility Board of Michigan (CUB).

**Q. Please summarize your experience in the field of utility regulation.**

A. I have worked since 2015 in positions related to clean energy, primarily on behalf of local governments and non-profit organizations. A significant portion of that work has included analysis of MPSC rate and other cases and supporting local government participation in rate cases and other MPSC proceedings. From 2015 to 2017 I organized and led the Municipal Street Lighting Coalition, a group of 24 municipalities served by DTE Energy, which intervened in cases U-17767, U-18014, U-20836 and U-21297 and participated in the subsequent MPSC-ordered street lighting collaborative. I organized and supported the intervention of several municipalities receiving street lighting services from Consumers Energy in cases U-20134, U-20697, U-20963, U-21224 and U-21389. I have submitted comments in several other case dockets on behalf of MI-MAUI and have participated in various MI Power Grid working groups and the Electric Distribution Planning working group. I directed MI-MAUI's intervention in DTE Energy's Voluntary Green Power case U-20713.



VERITEXT LEGAL SOLUTIONS

In the field of consumer protection, I am president and board chair of the Washington Public Interest Research Group (WashPIRG), an independent, non-partisan, non-profit organization based in Seattle that works to protect consumers and promote good government. I am also an officer of the WashPIRG Foundation, an affiliated research and public education organization. I was Executive Director of WashPIRG from 1989 to 1992 and worked on a number of consumer protection issues during that time and in more junior positions prior to that. I also served until 2020 as an officer of the PIRG in Michigan (PIRGIM) Education Foundation, a non-partisan consumer protection and good government public education and research organization based in Ann Arbor.

I am currently a stakeholder co-chair of the Commission's Data Analysis and Regulatory Review working group, and I am a member of the Commission's Low Income Energy Policy Board.

My energy-related work experience, educational and professional development background are summarized in my resume, provided as Exhibit CUB-1.

**Q: Please list your training and education relevant to the field of utility regulation.**

- EUCI Outdoor Street Lighting Conference, June 2019
- EUCI Electric Cost-of-Service - Essential Concepts for a Changing Industry, July 2019
- MSU-IPU Accounting and Ratemaking course, September 2020
- EUCI Utility Green Tariffs: A to Z course, November 2020
- MSU-IPU Advanced Regulatory Accounting and Auditing course, October 2021
- NRRI Regulatory Training Institute, Regulating Public Utility Performance course, 2022.

- EUCI Advanced Rate Design for Cost Effective Tariffs conference, 2024.

**Q. Have you testified before this Commission or as an expert in any other proceedings?**

A. I have previously testified before the Michigan Public Service Commission (Commission) in the following cases:

- Case No. U-20530 (I&M PSCR Reconciliation case)
- Case No. U-20561 (DTE Electric Company Electric General Rate Case)
- Case No. U-20697 (Consumers Energy Company Electric General Rate Case)
- Case No. U-20836 (DTE Electric general rate case)
- Case No. U-20963 (Consumers Energy Company Electric General Rate Case)
- Case No. U-21087 (DTE Electric PrePay case)
- Case No. U-20836 (DTE Electric Company Electric General Rate Case)
- Case No. U-21224 (Consumers Energy Company Electric General Rate Case)
- Case No. U-21297 (DTE Electric Company Electric General Rate Case)
- Case No. U-21389 (Consumers Energy Company Electric General Rate Case)
- Case No. U-21534 (DTE Electric Company Electric General Rate Case)
- Case No. U-21585 (Consumers Energy Company Electric General Rate Case)

I have testified before the Kentucky Public Utilities Commission in rate cases 2020-349 and 2020-350, the combined Kentucky Utilities and Louisville Gas & Electric, electric and gas rate cases.

**Q. What is the purpose of your testimony?**

**A**. I am testifying about the impact on residential customers of increasing gas rates, the moderating impact on inflation of productivity on costs and on allocation of uncollectible expenses.

**Q. Are you sponsoring any exhibits?**

**A.** I am sponsoring the exhibits listed below:

Exhibit CUB-1: Resume of Richard Bunch

Exhibit CUB-2: U-20757 MPSC EAAC Report

Exhibit CUB-3: CECo WP-SMG-22 Net Write-Off History

Exhibit CUB-4: MI CUB Gas Transition Report

Exhibit CUB-5 U-21490 Redacted Direct Testimony of S. Mclean

Exhibit CUB-6: Productivity adjustment to inflation factor

## II. IMPACT ON RESIDENTIAL CUSTOMERS OF INCREASING GAS RATES

**Q. Why are you concerned about the residential rate increase proposed by the Company in this rate case?**

**A.** I am concerned about affordability and customer protection issues, and while I appreciate references that Company witnesses make to priorities of the Low-Income Energy Policy Board and Energy Affordability and Accessibility Committee (EAAC), I believe more needs to be done to support and protect residential customers.

Consumers proposes to increase its main residential rate (Single Family Dwelling A) by 12.1%. Such a substantial increase promises to make it harder for vulnerable customers, principally including low-income and senior customers, to make ends meet. Already there

are signs that many Consumers gas customers are struggling, and too few are receiving assistance to help keep their energy costs bearable and keep their homes livable.

**Q. Do you support the Company's investments in assuring reliable and safe gas supplies?**

A. I support safety and reliability but assess them within the larger framework of energy security.

Commission staff has recommended that the MPSC adopt the following definition of home energy security, based on EAAC discussions:

> *Home Energy Security is the reliable access to and availability of energy for meeting diverse and varied household needs. Home energy security is driven by several factors including but not limited to energy infrastructure, energy efficiency of housing stock, predictability and fairness of charges, and energy affordability. It can be improved through measures to address system reliability, home weatherization, energy education, consumer protection plans, and affordability strategies.*[1]

Formal adoption of this definition is pending Commission action in response to the Staff report.

I provide this definition to underscore that "reliable access" has multiple dimensions: not only reliable distribution and safety but also affordability and equity. While the Company's proposed investments in reliability and safety are important, they should not take precedence over other aspects of energy security. Moreover, because proposed reliability and safety investments would be so expensive, as reflected in the Company's proposed

[1] U-21806 Exhibit CUB-2 EAAC U-20757 Interim Progress Report, 12/26/2024, p. 34.

12.1% rate increase for residential customers, they threaten to undermine other, equally important, aspects of energy security. Put plainly, customers' energy security is not improved if gas service becomes safer and more reliable yet so expensive that they fall far behind on their payments, engage in energy self-deprivation or skimp on other necessities to pay their gas bills and ultimately default and drive up uncollectible expenses. The Commission should seek a more equitable balance between safety and reliability on the one hand and affordability, equity and consumer protection on the other.

**Q. How do you know that a 12.1% rate increase would strike an inequitable balance between safety and reliability versus affordability, equity and consumer protection?**

**A.** First, there are already strong indications that efforts to help customers stay current on their bills and maintain their service are being overwhelmed by prior rate hikes. Second, the Company's proposed residential rate increase of 12.1% is much higher than expected inflation through the test year, which threatens to make it even harder for customers to pay their energy bills.

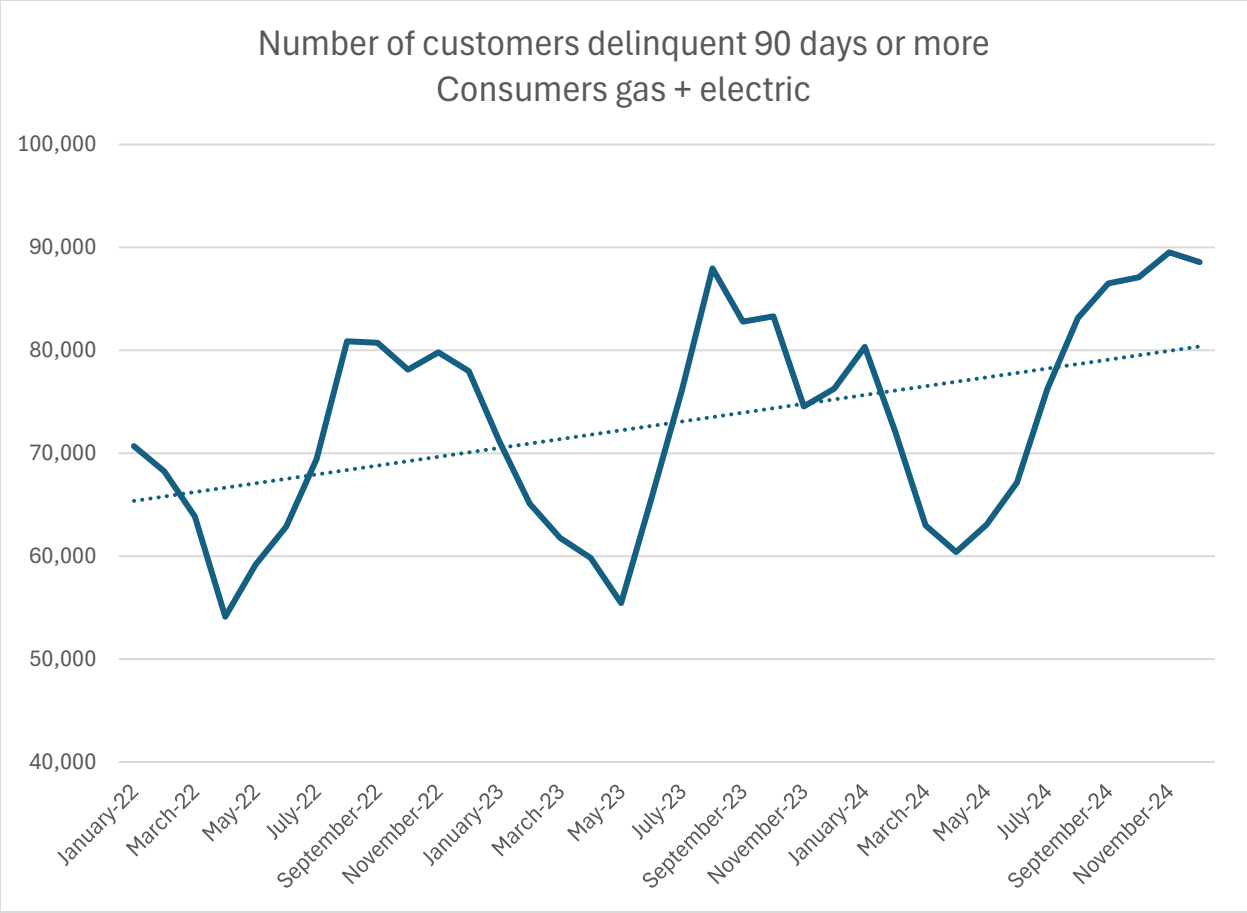
**Q. What indications can you cite that residential customers are already struggling to stay current on their energy bills?**

**A.** Long-term delinquent accounts and residential uncollectibles are both growing sharply, indicating that a growing number of customers cannot afford to pay the Company's rates.

**Q. What data can you provide to support your testimony that the number of long-term delinquent accounts is growing?**

**A.** I can provide data gleaned from the Company's quarterly reports filed in the docket for case U-18120. The number of accounts that are 90+ days in arrears has been growing significantly.[2] See Figure 1.

*Figure 1*




*Source: compilation of Consumers U-18120 quarterly reports.*

Long-term delinquencies have grown by about 25% over the past three years, as shown by the best-fit line shown in the chart. During that time, Consumers' residential customer

[2] Gas and electric delinquencies are not reported separately.

count has gone from 1,677,801 (January 2022) to 1,688,064 (September 2024), an increase of only about 0.6%.[3] Growth in customer count or sales cannot explain such a large growth in seriously delinquent accounts.

**Q. How much have uncollectible expenses increased?**

A. From 2021 to 2023, residential uncollectible expenses increased 53.7%:

| | 2021 | 2022 | 2023 |
|---|---|---|---|
| Total Residential | $9,566,394 | $11,726,019 | $14,702,786 |

*Source: U-21806 Exhibit CUB-3 Consumers WP-SMG-22, Net Write-off History*

Customer count, again per the Company's U-20757 reports, increased only about 1.1% from January of 2021 (1,670,228) to December of 2023 (1,688,066), and clearly could not contribute meaningfully to the observed increase in uncollectibles.[4]

**Q. Have these observed energy security impacts resulted from rates increasing faster than inflation?**

**A.** No. Consumers' residential rates have not risen faster than inflation over the past few years. Consumers' average residential gas bill today is about 24% higher than the rates approved in 2020 (Figure 2). The Consumer Price Index has risen about 24% since January of 2020.[5] The import of this observation is that allowing rates to rise at the same rate as inflation is not inconsequential – economically vulnerable customers suffer, nonetheless.

The impact of inflation on consumers has been widely discussed but the Commission should be mindful that inflation impacts low-income consumers more than others. This amplified impact happens because prices for necessities, such as gas service, tend to rise

[3] U-21806 Part III – Standard Filing Requirements, Attachment 14, p.4.

[4] U-21806 Part III – ibid.

[5] https://www.bls.gov/data/inflation_calculator.htm

faster than prices for discretionary purchases.[6] Low-income customers spend higher percentages of their income on necessities than on discretionary items, exposing them to a higher effective inflation rate. Also, they cannot moderate their purchases of necessities when prices rise to the extent they can of discretionary items.

**Q. What are the longer-term rate impacts of the Company's spending plans?**

**A.** The Company's spending plans would severely impact residential rates.[7] CUB's recent study of the bill impacts of natural gas investment plans in Michigan conservatively estimated that Consumers' spending plans would result in a 158% increase in residential rates in 2050 versus today, averaging 3.86% per year.[8] If Consumers' rates grew at the pace of inflation, rates in 2050 would be 36% lower than projected. (Figure 2)

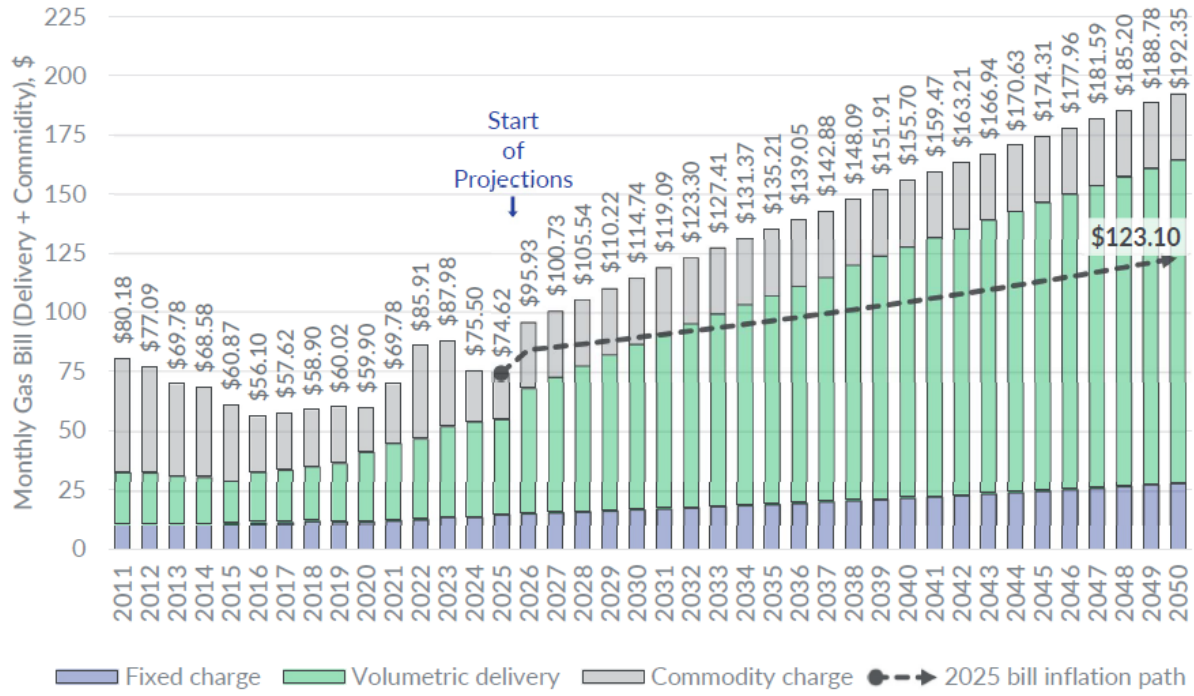
[6] The cost of 'basic necessities' has risen slightly more than inflation over the last 30 years : Beyond the Numbers: U.S. Bureau of Labor Statistics, June 2015. https://www.bls.gov/opub/btn/volume-4/the-cost-of-basic-necessities-has-risen-slightly-more-than-inflation-over-the-last-30-years.htm

[7] CUB's study (ref. next note) projects future capital expenditures and rate base through 2050 based on published utility investment plans and historical trends.

[8] Exhibit CUB-4, "Investor-owned Utility Gas Distribution Capital Expenditure: A Study on the Potential Bill Impacts of Business-As-Usual Investment in Michigan," CUB of Michigan, March 2025, p. 25.

*Figure 2*

*Figure 4.1: Consumers Typical Residential Monthly Bill Projections, 2011–2050*




Sources: Historical delivery charges from MPSC's natural gas rate history document < https://www.michigan.gov/mpsc/-/media/Project/Websites/mpsc/consumer/nat-gas/gasrates.pdf>. Projected delivery charges are consultant projections.

*Source: U-21806 Exh CUB-4, p.21*

The Commission should be aware that the Company's proposed 12.1% residential rate increase is not a one-off request. To the contrary: the Company's plans clearly foreshadow repeated rate increases running well ahead of expected inflation.

**Q. Would the provision of more billpayer assistance alleviate this situation?**

**A.** It would help, but billpayer assistance has risen sharply and we still see more and more customers falling far behind in their payments and ultimately defaulting.

Specifically, company witness Byrom states that in 2023, Consumers electric and gas customers received $9.2 million in MEAP assistance, $37.8 million in State Emergency

Relief payments and $18.9 million in Home Heating Credit assistance.[9] By comparison, Company witness McLean testified in the preceding gas rate case that in 2022 the Company's customers received $10.28 million in MEAP assistance, $20.3 million in SER payments and $11.5 million in Home Heating Credit assistance.[10] Summing these three programs, I find that Consumers' customers received almost $24 million (or 57%) more in various forms of assistance in 2023 than in 2022. Yet the number of customers who are more than three months behind, and the dollar value of residential uncollectibles, are both surging.

**Q. Why has greatly increased assistance not offset the observed increase in delinquent accounts and uncollectibles?**

**A.** As Company witness Byrom observes, "only one in six LMI (Low and Moderate Income) customers engage in Consumers Energy Assistance programs with the majority of these interactions driven by immediate crises that limit ability to introduce solutions and programs given the urgent customer need."[11] The LMI Customer Support investments that witness Byrom proposes to increase engagement are crucial and I support them. Still, even if Consumers managed somehow to double the engagement of LMI customers, two-thirds of LMI customers would not be reached. Assistance is a *deus ex machina* solution: it is not realistic to suppose it can ever "solve" the problem of unaffordable rates. Far and away the

[9] U-21806, Direct Testimony of Consumers Witness Jessica R. Byrom, p. 17, lines 17-21.

[10] Exhibit CUB-5, U-21490, Direct Testimony of Consumers Witness Steven Q. McLean, p. 22, lines 7-13.

[11] Byrom direct, p. 19, lines 9-12.

better solution is to offer rates that are affordable such that LMI customers do not need assistance to begin with.

**Q. Would you favor an assistance scheme that would serve all LMI customers?**

**A.** What I would favor is rates that make gas service affordable for more LMI customers so they will not need assistance. Increased assistance is neither a universal nor an equitable solution to the affordability problems we are seeing, even if it is an unavoidable palliative, reducing pain but not addressing the cause.

With current rates, an assistance scheme that could serve all needs and be equitable is chimerical: such a vision is illusory and the costs even if it were attainable would be so high as to be inequitable to all other customers and taxpayers. State Emergency Relief and the Home Heating Credit are federally funded – meaning that the Company's unaffordable rates are being passed on to US taxpayers. LIHEAP funds are recovered from all ratepayers, so while not strictly a tax, this is merely a different externalized subsidy for the Company's unaffordable rates. Externalizing the impacts of unaffordable rates cannot be equitable.

**Q. What do you conclude from these observations?**

**A.** I conclude that increased assistance, while necessary given current realities, is not and can never be sufficient to overcome the impacts of unaffordable rates, nor can it ever be considered an equitable remedy for unaffordable rates.

**Q. How do you recommend the Commission respond to your observations?**

A. I recommend that the Commission carefully balance the Company's spending proposals against the human impacts of the rate increases that inevitably result from that spending. Customers want safety and reliability but those are empty desires when they cannot afford

the service to begin with. Past rate increases have created the situation I detail above, and a further 12.1% increase can only exacerbate this dangerous trend. It is crucial that the Commission set a clear standard that rates rising faster than productivity-adjusted inflation are not sustainable and will not be authorized.

In this testimony, I recommend a framework for the Commission to restrain spending increases with reference to inflation and productivity, and to reduce the amount of uncollectibles allocated to residential customers. Both measures can improve affordability for residential customers.

## III. PRODUCTIVITY ADJUSTMENT TO INFLATION FACTOR

**Q. You stated above that the Company's proposed residential rates are much higher than expected inflation. What rate of inflation is expected through the test year?**

A. Company witness Rayl assumes an inflation factor of 2.4% for 2025 and 2.5% for 2026.[12]

**Q. How do the Company's proposed gas rates compare to the expected rate of inflation?**

A. The Company's proposed rates are as follows, including comparison to expected 2025 inflation:[13]

| Rate class | % increase | vs. 2.4% inflation |
|---|---|---|
| Total residential | 12.0% | 5x |
| Total General Service | 4.5% | 1.88x |
| Total transportation | 26.9% | 11.2x |
| Total Service (Delivery & Fuel) | 10.8% | 4.5x |

[12] U-21806 Direct Testimony of Company Witness Heather L. Rayl, p12, lines 4-5.

[13] The test year starts in November 2025, so I use the Company's expected 2025 inflation as my benchmark.

From an equity standpoint, it is notable that the Company's proposed residential increase is nearly triple the increase proposed for the general service rates, which itself is far above the expected pace of inflation.

**Q. Are the Company's costs proposed to rise faster than inflation?**

**A.** The simple answer is yes, otherwise proposed rate hikes would not exceed inflation. Understanding why this is happening is not quite as simple. For example, the Company's summary of proposed O&M costs (Exhibit A-13, HLR-42, Sch. 5.1) shows Net Operations and Maintenance expenses of $320,950,000 for calendar 2023 and projects $297,904,000 for calendar 2026 (Line 34), suggesting that the Company's costs are actually declining over time. This total, however, includes a number of pension and benefits costs as well as proceeds from the sale of the Appliance Service Program. Although containment of pension and benefits costs is inarguably important, these items are not useful for evaluating the Company's effectiveness at containing operating costs. By including only core operating functions (Compression and Storage, Gas Operations, Pipeline Integrity, Transmission, Gas Engineering and Supply, Customer Experience and Operations, Operations Support, IT and Security – operations and investments, Incentive Compensation and Corporate Services), I find that O&M expenses will increase from $273,884,000 actual in calendar 2023 to $321,033,000 projected for calendar 2026, or a 17.2% increase over that period. (U-21806 Exhibit CUB-6, p.4, row 35, column j) Compounded consumer product inflation over that period (per witness Rayl, 3.2% in 2024 actual, projected 2.4% in 2025 and 2.5% in 2026) would support an increase of only 8.32% (Exh CUB-6, p1, column f, row 5).

**Q. Does the Company apply an inflation factor to arrive at test-year cost projections in the instant case?**

A. Sometimes it does and sometimes it doesn't. The more important insight, though, is that budget lines that do not explicitly apply an inflation factor nevertheless have inflation embedded in their cost projections.

For example, witness Rayl compiles merit and inflation increases to O&M labor costs across all work groups in Exhibit A-13 (HLR-42), Sch. 5.1, columns d, e and f. However, many sponsoring witnesses for Exhibit A-13 projected their costs using methods other than inflation (e.g., changes in negotiated labor union rates). Their cost changes are included in column (g), Other Adjustments, which bundles labor and non-labor costs together. Detail on these changes can be gleaned from the sponsoring witnesses' exhibits and work papers. Witness Rayl does not provide a similar breakout of merit and inflation increases for capitalized labor costs summarized in Exhibit A-12 (HLR-35), Sch. B-5, but, again, details are provided in the sponsoring witnesses' exhibits and workpapers.

**Q. Why do you state that budget lines that do not explicitly apply an inflation factor nevertheless have inflation embedded in their cost projections?**

**A.** By examining sponsoring witnesses' testimony and exhibits, it is easy to see that their costs are projected to grow, but many do not apply a standard inflationary factor.

For example, witness Pnacek provides testimony on Gas Operations O&M, with total amount shown on line 7 of Exhibit A-13 (HLR-42), Sch. 5.1 and no amounts showing in the Inflation & Merit columns. Witness Pnacek states, "Inflation was not used to determine

the program funding in this case…"[14] He further explains, "For forecasts developed for future years, SLRs generally reflect current payroll costs levels with an annual forward-looking adjustment of 3% per year, which is consistent with the contractual labor agreement between the Company and its operating employees' union."[15] (SLRs = Standard Labor Rates) Thus, I conclude that increases functionally equivalent to inflation are embedded in Gas Operations O&M costs even though no merit and inflation increases are shown for Gas Operations in Exhibit A-13 (HLR-42), Sch. C-5.1.

Several other sponsoring witnesses propose significant cost increases but show no inflation and merit increases. By going to their exhibits and workpapers, though, it is straightforward to demonstrate that their labor costs are projected to increase.

**Q. How much are the Company's labor costs increasing?**

**A.** I find that the Company's 2026 O&M and capitalized labor costs are projected to be 28.7% higher than the historical average from 2023-2024. (Exhibit CUB-6, p1, column c, row 4). I calculated this amount by adding labor-cost detail from sponsoring witnesses to witness Rayl's summary O&M and Capital expense worksheets. (modified as Exhibit CUB-6, pp3-4).

Compounded actual and projected inflation for 2025-2026 is only 4.96% (Exhibit CUB-6 p1, column e, row 5). This calculation is essentially the same method that several Company witnesses use to inflate historical costs, with the difference being that Company witnesses use a 2023 cost baseline whereas I am using 2023-2024 average costs.

[14] U-21806, Direct Testimony of Company Witness James P. Pnacek, p. 6, lines 19-20.

[15] Pnacek, p. 4, lines 20-23.

In short, the Company's labor costs are increasing much faster than inflation.

**Q. Would you recommend the Commission approve rates that rise at the same pace as inflation?**

A. No. I would recommend that the Commission hold rate increases below the expected rate of inflation. As I demonstrated earlier, recent rate increases keeping pace with inflation have had significant affordability impacts on customers. In addition to the unacceptable rate impacts, though, rates that rise at the rate of inflation are not justified by cost because inflationary pressures on costs should be mitigated by gains in productivity. Viewed from a different perspective, this means that the Company should be able to fully recover its costs with rates that rise slower than inflation if it realizes productivity gains on a par with the rest of the US economy.

As a regulated utility, the Company does not face competitive pressures to contain its costs. The Commission's review of rates should recognize that providing the Company a reasonable opportunity to recover its costs includes a reasonable expectation that it demonstrate over time that it is attaining productivity gains comparable to those of companies operating in competitive markets.

**Q. Has the Commission ordered the Company to demonstrate that it includes productivity gains in its test year cost projections?**

**A.** Yes, it has. The Commission included this requirement in its recent order in Consumers electric rate case U-21585, accepting the ALJ's recommendation that it "…direct

Consumers to present more detailed evidence to demonstrate that it is in fact offsetting inflation by productivity in the Company's next rate case."[16]

**Q. Has the Company responded to the Commission's U-21585 order regarding productivity with its filings in this rate case?**

A. No, it has not. Consumers filed this case before the Commission issued its order in case U-21585. Several witnesses claim their proposed expenditures will improve productivity but provide no explicit or quantitative analysis of financial benefits.

For example, witness Pascarello states that "(e)ach department within GE&S analyzed the work activities and factored in productivity improvements to determine the necessary number of employees."[17] Yet, witness Pascarello projects that O&M labor costs for Gas Engineering & Supply will rise from the 2023-2024 average of $11,788,000 to $16,271,000 in the test year,[18] and that capitalized labor will grow from $138,617,000 in 2023-2024 to $181,242,000 in the test year. In total, labor for Gas Engineering & Supply is projected to increase from $150,405,000 to $197,513,000, or 31.3%. Despite claiming that several specific investments will boost productivity,[19] witness Pascarello provides no explanation or evidence to show how this dramatic increase in labor costs is consistent with the purported productivity improvements.

[16] Case No. U-21585, Order, March 21, 2025, pp. 355-356.

[17] U-21806 Direct Testimony of Company Witness Kristine A. Pascarello, p. 10, lines 11-13.

[18] Exhibit CUB-6, p. 4, row 7.

[19] Pascarello direct, p. 49, line 14; p. 83, line 4; p. 85, line 20.

Witness Baker claims productivity benefits for Asset Replacement Program and Security investments[20], but projects capital labor for IT and security to increase from 2023-2024 historical average of $4,382,000 to $9,242,000 in the test year – more than doubling.[21] Witness Baker's projected O&M labor costs would rise from 2023-2024 average of $10,419,000 to $15,729,000 in the test years.[22] Between capitalized and O&M labor, witness Baker projects 69% higher labor costs in the test year than the 2023-2024 historical average. Increasing labor costs by 2/3 is not consistent with claims of increased productivity, and witness Baker provides nothing else by which to judge these claims.

Witness Foster supports witness Baker's costs with additional claims about enhanced productivity from Corporate Service technology investments,[23] but like witness Baker omits any evidence in support of these claims. Witness Joyce also cites productivity benefits of IT projects included in witness Baker's projections, without providing substantiating evidence.[24]

**Q. What productivity offset do you recommend the Commission apply?**

A. I recommend that the Commission apply productivity offsets to reduce the impact of inflation on costs.

[20] U-21806 Direct Testimony of Company Witness Stacy H. Baker, p.57, line 5; p61, lines 7-8; p.63 line 32; p71, lines 22 and 31; p93, line 1; p117, line 21.

[21] Exhibit CUB-6, p. 3, row 3.

[22] Exhibit CUB-6, p. 4, rows 10 and 11.

[23] U-21806 Direct Testimony of Company Witness Matthew J. Foster, p. 16, line 31; p. 17, line 1; p. 17, line 34; p. 21, lines 5 and 15.

[24] U-21806 Direct Testimony of Company Witness Timothy K. Joyce, p. 46, line 22.

The US Bureau of Labor Statistics publishes productivity factor changes for sectors, industries, asset categories, geographic areas and time periods. I recommend that the Commission require the Company to offset inflationary increases in labor costs using the BLS labor productivity figures for Michigan. Using the Michigan figures reflects that Consumers is primarily competing in the Michigan labor market. Average annual change in labor productivity in Michigan from 2014-2023 was 0.79% (U-21806 Exhibit CUB-6), p.2, column k, row 2). This factor should be applied to all O&M labor and labor costs added to rate base as an offset to explicit or embedded inflation factors.

For non-labor expenses, I recommend that inflation be offset by the BLS' Total Factor Productivity, in this case using national figures on the basis that equipment, material and capital costs operate substantially as national markets. Average national annual change in Total Factor Productivity from 2015-2024 was 0.83% (U-21806 Exhibit CUB-6), p.2, column k, row 3). This factor should be applied to all non-labor O&M expenses and non-labor additions to rate base as an offset to explicit or embedded inflation factors. CUB witnesses Denzler and Veerapaneni conduct this analysis in their granular reviews of projected spending.

For both labor and non-labor productivity factors, I recommend using BLS averages for the past ten years available. Productivity factors can vary substantially from year to year, making a shorter-term average an undependable predictor of future productivity changes.

**Q. How do you recommend the Commission apply the productivity offset?**

**A.** I recommend that the Commission limit O&M and capitalized labor costs to 2023-2024 historical average levels plus compounded 2025-2026 labor Productivity-Adjusted

Inflation (hereinafter, PAI) of 3.37%. (Exhibit CUB-6, p1, column e, row 7). This figure is determined by subtracting average annual Michigan labor productivity factor of 0.79% from witness Rayl's inflation factors for each year, then compounding over the two-year period.

Regarding non-labor costs, I recommend that the Commission apply to 2023-2024 historical average costs the non-labor Total Factor Productivity adjustment to inflation for 2025-2026 of 3.29% (Exhibit CUB-6, p1, column e, row 9). I defer to CUB witnesses Denzler and Veerapaneni to apply the non-labor productivity offset to O&M and capital project costs.

**Q. Should the Commission apply the offset by subtracting it from the Company's input annual inflation rates?**

**A.** No. Because the Company does not use the assumed inflation factor to project most labor costs, offsetting the inflation factors would impact labor cost projections for only a few of the line items in the O&M cost summary and none of the capitalized labor projections. The offset should be applied to all labor costs, not only those projected using a standard inflation factor. The amounts shown in column c, rows 8-10 (Exhibit CUB-6, p. 1) are the productivity-adjusted inflation labor costs derived by breaking out labor costs line-by-line for both O&M and capital projects (Exhibit CUB-6, pp. 3-4, columns j-n). I identified those labor costs from the exhibits of the witnesses sponsoring costs that appear in witness Rayl's O&M and Capital projects summary exhibits.

**Q. Should the Commission apply the productivity offset to line items where costs are subject to negotiated agreements?**

**A.** Yes, it should.

Labor rates and productivity measure different things. Rates tell us how much people are paid for a given period of work. Productivity tells us how much work they get done during that period. Applying a productivity offset to a labor cost subject to negotiated rates does not impact those rates. It is reasonable to expect that the Company should improve at organizing and supporting its workers to achieve greater productivity over time.

**Q. How do the Company's projected costs compare to productivity-adjusted inflation?**

**A.** The Company projects total O&M and capitalized labor cost will grow by 28.7% from 2023-2024 average to the test year. (Exhibit CUB-6, p. 1, row 4, column c). It projects total labor costs $93,036,000 higher than indicated by historical average actuals increased for sales and productivity-adjusted inflation. (Exhibit CUB-6), p. 1, row 3, column d). This figure is 18.1% higher than the amount justified by productivity-adjusted inflation from 2023 to 2026. (Exhibit CUB- 6), p. 1, row 3, column e).

It is noteworthy that the biggest projected cost growth from 2023 to 2026 is in capitalized labor, which is projected to be 21.8% higher than the growth supported by productivity-adjusted inflation. (Exhibit CUB-6), p. 1, row 2, column e) Looked at another way, the Company proposes to increase its capitalized labor expense from $328,223,000 in 2023 to $445,866,000 in 2026, an increase of 35.8% in only three years' time.

**Q. How do you recommend the Commission use this information in the instant rate case?**

**A.** I recommend that the Commission apply the 2025-2026 Productivity-Adjusted Inflation factor to all 2023-2024 historical actual O&M and Capital project labor costs to determine 2026 spending projections justified by general economic conditions. My recommended amounts for each work group are shown on Exhibit CUB-6 column (p) of page 3 (Capital labor) and page 4 (O&M labor).

I also recommend that the Commission apply a 3.29% total factor productivity adjustment to inflation for 2023-2024 actual costs to determine reasonable test-year non-labor costs, both O&M and capital. I defer to CUB witnesses Denzler and Veerapaneni for application of this offset to specific line items.

If the Commission finds that additional spending is justified by safety, reliability, security or other compelling needs that have emerged since the 2023-2024 years that I use for computing average annual expenses, then I recommend identifying 2023-2024 unit costs for those activities, adding Productivity-Adjusted Inflation, then multiplying by number of units to determine a reasonable total cost.

**Q. Please describe what you recommend the Commission require for future case filings.**

**A.** I recommend that the Commission replicate the order it issued in Consumers electric rate case no. U-21585, namely that it should direct Consumers to present more detailed evidence to demonstrate that it is in fact offsetting inflation by productivity in the Company's next gas rate case.

## IV. ALLOCATION OF UNCOLLECTIBLES

**Q. How does the Company propose to allocate uncollectible expenses among customers?**

A. Allocation of uncollectible expense is not addressed by Company witnesses in testimony. However, the Cost of Service study shows that the Company proposes to allocate 89.05% of net write-offs to the Residential rates. (U-21806 Exhibit A-7 (SMG-1), Sch F-1, p7, row 21). This allocation adds $13,649,000 to the residential revenue requirement. (U-21806 Exhibit A-16 (SMG1), Sch F-1,EX_Total cell F454).

**Q. How was the allocation percentage determined?**

A. It was determined from the three-year historical average of net write-offs caused by customers served under each rate. (Exhibit CUB-3 Company workpaper U-21806 WP-SMG-22 Net Write Off History).

**Q. Is this method of allocation consistent with the Commission's past orders on allocation of uncollectible expense?**

A. No, it is not. The Commission ordered allocation of gas uncollectibles as a general cost of doing business as part of its decision in DTE Gas Company's rate case no. U-20940. (December 9, 2021, order in Case No. U-20940, pp. 189-190.) In that case, the Commission ordered that uncollectibles should be allocated on Cost of Service plus Cost of Gas.

**Q. Has the Commission spoken to allocation of uncollectibles in electric rate cases?**

A. Yes, it has ordered allocation of uncollectibles by rate class revenue in Consumers and DTE electric rate cases.

Most recently, in its order for Consumers electric rate case no. 21389, the Commission held:

*"…that the inability of one member of a class to pay a utility bill is only attributable to an individual customer and not an entire class. Thus, uncollectibles should not be allocated to a particular customer class. In addition, the Commission finds that past uncollectibles amounts (or lack thereof) are not relevant to cost allocations going forward. The Commission reiterates that uncollectibles expense is a general cost of doing business to be shared by all customers.*"[25]

Consumers itself supported that finding in its replies to exceptions in the same case, averring firmly, "Uncollectible expenses are a general cost of doing business."[26]

In case no. U-21297, a DTE Electric general rate case, the Commission held that "uncollectible costs are a general cost of doing business and should be allocated to all customer classes based on revenue."[27]

**Q. Has the Commission addressed allocation of uncollectibles in Consumers gas cases subsequent to its order in DTE case no. U-20940?**

**A.** No, it has not. Consumers gas cases no. U-21148 (2022), U-21308 (2023) and U-21490 (2024) were all settled without reference to allocation of uncollectibles.

**Q. What allocation of gas uncollectibles do you recommend in this case?**

**A.** I recommend that the Commission order the Company to allocate uncollectible expense to each rate class according to Cost of Service plus Cost of Gas, the same method as the Commission ordered DTE to adopt in 2021.

[25] Case No. U-21389, Order, March 1, 2024, p. 228.

[26] Case No. U-21389, filing U-21389-0402, Consumers Energy Company Replies to Exceptions, January 23, 2024, p. 113.

[27] Case No. U-21297, Order, December 1, 2023, pp. 295-296.

While I have testified as a witness for MI-MAUI in recent electric rate cases (Consumers U-21389 and DTE U-21297) opposing allocation of uncollectibles to streetlight customers by revenue, the Commission did not adopt my recommendations. There appears to be no other basis for making an exception in this case either.

**Q. What would be the impact on required revenue of the allocation change you are recommending?**

**A.** The Company's proposed rate design revenue for residential rates is 72.5% of total revenue ($1,301,551,000/$1,794,891,000). Allocating 72.5% of uncollectibles to the residential rate class would result in $11,112,380 of required revenue. This amount is about $2.5 million less than the $13,649,000 uncollectibles allocation to residential rates proposed by the Company, based on historical net write-offs per class. The reduced allocation to residential rates should be reallocated to other rates based on their share of projected revenue.

## V. RECOMMENDATIONS

**Q. Please summarize your conclusions and recommendations to the Commission.**

A. On behalf of CUB, I recommend that the Commission:

(1) Limit the Company's spending increases to inflation offset by either labor productivity factor or total factor productivity;

(2) Order the Company to present more detailed evidence to demonstrate that it is in fact offsetting inflation by productivity in the Company's next gas rate case.

(3) Allocate uncollectible expenses according to revenue, not historical uncollectibles by rate class.

My silence in regard to any position taken by the Company in its application or direct testimony in this proceeding does not indicate CUB's endorsement of that position.

## TABLE OF RECOMMENDED DISALLOWANCES

| Description | Projected | CUB recommendation | Difference |
|---|---|---|---|
| O&M labor costs | $160,864,000 | $149,390,000 | ($11,474,000) |
| Capitalized labor | $455,866,000 | $323,272,000 | ($122,594,000) |

**Q. Does that complete your testimony?**

A. Yes.

MS. HILLYER: At this time, also on behalf of CUB, I move to bind into the record the prefiled direct testimony of Ram Veerapaneni, which consists of a cover page, a table of contents, and 20 pages of questions and answers, and I also move for the admission of Mr. Veerapaneni's exhibits, which consists of Exhibits CUB-7 through CUB-12.

JUDGE VARCHETTI: All right. Are there any objections to the admission of Mr. Veerapaneni's direct testimony or the associated exhibits?

Hearing none, the testimony is bound into the record, and the exhibits are admitted.

MS. HILLYER: Thank you, Your Honor.

(Direct Testimony bound in)

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

| | |
|---|---|
| In the matter of the application of **CONSUMERS ENERGY COMPANY** for authority to increase its rates for authority to increase its rates for the distribution of natural gas and for other relief. | U-21806 |

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# DIRECT TESTIMONY OF RAM VEERAPANENI

## ON BEHALF OF

## CITIZENS UTILITY BOARD OF MICHIGAN

**April 23, 2025**

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**DIRECT TESTIMONY OF RAM VEERAPANENI FOR CUB**
**CASE NO. U-21806**

## I. INTRODUCTION & QUALIFICATIONS

**Q. Please state for the record your name, position, and business address.**

A. My name is Ram Veerapaneni. My business address is 115 West Allegan Street, Suite 710, Lansing MI 48933.

**Q. Please briefly describe your educational background.**

A. I have a Master of Science degree in Mechanical Engineering from Wayne State University, Detroit, Michigan. I have a bachelor's degree in mechanical engineering from Andhra University, Vishakhapatnam, India. I completed 20 credits for a Master of Business Administration degree at Wayne State University.

**Q. Please summarize your employment and professional experience.**

A. I retired as a Principal Engineer at the DTE Gas Company after working for 23 years in various positions. Before joining DTE, I worked for the Michigan Public Service Commission (MPSC or Commission) for 22 years. I have worked for 5 Lakes Energy as a Senior Consultant since September 2019. Details of my experience are shown in Exhibit CUB-7 to this testimony.

**Q. Please give us some examples of utility cases in which you have provided testimony or participated in settlement negotiations on behalf of the MPSC Staff.**

A. I testified or otherwise participated in the following cases:

- Case No. U-3665 Revision of Michigan Gas Safety Code
- Case No. U-4717 Consumers Power Company Rate Case
- Case No. U-5304 Michigan Consolidated Gas Company to revise its Purchased Gas Adjustment Clause - Rule 30



VERITEXT LEGAL SOLUTIONS

- Case No. U-5365 Michigan Consolidated Gas Company Rate Case
- Case No. U-5732 Consumers Power Company Rate Case
- Case No. U-5748 Michigan Gas Utilities Company for approval of a 60-day emergency gas service agreement with Michigan Consolidated Gas Company
- Case No. U-5759 Consumers Power Company for authority to amend its Purchased Gas Adjustment Clause
- Case No. U- 5955 Michigan Consolidated Gas Company Rate Case
- Case No. U-6486 Great Lakes Steel / Michigan Consolidated Gas Company
- Case No. U- 6839 Great Lakes Steel / Michigan Consolidated Gas Company
- Case No. U-8409 Rate charges for gas service by Michigan Consolidated Gas Company
- Case No. U-8565 Michigan Consolidated Gas Company GCR Plan
- Case No. U-8565-R Michigan Consolidated Gas Company GCR Reconciliation
- Case No. U-8635, U-8812, U-8854 Special Contract Michigan Consolidated Gas Company
- Case No. U-8779 Michigan Gas Processors Company for authority to construct and operate the Oceana/Mason Pipeline
- Case No. U-8847 Michigan Consolidated Gas Company/Panhandle Eastern Pipeline Company
- Case No. U-8870 Michigan Consolidated Gas Company GCR Plan
- Case No. U-8870-R Michigan Consolidated Gas Company GCR Reconciliation
- Case No. U-8954 Northern States Power Company GCR Plan
- Case No. U- 8955 Wisconsin Public Service Corporation GCR Plan

- Case No. U-9175 Peninsular Gas Company GCR Plan
- Case No. U-9257 Consumers Power Company - Rule Expansion
- Case No. U-9263 Consumers Power Company Rule Building Meter
- Case No. U-9297 Northern States Power Company GCR Plan
- Case No. U-9298 Wisconsin Public Service Corporation GCR Plan
- Case No. U-9323 Michigan Gas Company Rate Case
- Case No. U-9475 Michigan Consolidated Gas Company Rate Case
- Case No. U-9650 Michigan Consolidated Gas Company GCR Plan

**Q. What are the cases in which you filed testimony as a consultant for 5 Lakes Energy?**

A. I filed testimony in the following cases:

- U-20479 - SEMCO Energy Gas Company Rate Case.
- U-20642 - DTE Gas Company Rate Case.
- U-20650 - Consumers Energy Company Gas Rate Case.
- U-21226 - Northern States Power Company Gas Rate Case.
- U-21490 - Consumers Energy Company Gas Rate Case.

**Q. What topics are you addressing in your testimony?**

A. I am addressing the following topics in this case:

1. Capital Expenditures:
    a. Asset Relocation
    b. Regulatory Compliance
    c. Capacity/ Deliverability
    d. Distribution Plant - Material Condition

e. Gas Operations - Other

f. Gas Distribution

g. Gas Compression and Storage

2. Operations & Maintenance Expenditures.

a. Gas Operations

b. Gas Engineering & Supply

c. Field Operations - Services

d. Gas Operations - Other

e. Regulatory Compliance

f. Gas Compression

g. Gas Storage O&M

**Q. Do you agree with all other aspects of the company proposals?**

A. No. The absence of discussion on other matters in my testimony does not indicate agreement with the other items contained in the rate case filing.

**Q. Are you sponsoring any exhibits?**

A. Yes. I am sponsoring the following exhibits:

| | |
|---|---|
| Exhibit CUB-7. | Resume of R. Veerapaneni |
| Exhibit CUB-8: | MPSC Consumers Energy Company Projected Capital Expenditures/ Summary of Capital Expenditures |
| Exhibit CUB-9: | MPSC Consumers Energy Company Projected O&M Expenditures/ Summary of Expenditures |
| Exhibit CUB-10: | MPSC Consumers Energy Company Projected Capital |

| | | |
|---|---|---|
| | | Expenditures |
| | Exhibit CUB-11: | MPSC Consumers Energy Company Projected O&M Expenditures/ Projected O&M Expenditures: Gas |
| | Exhibit CUB-12 | U21806-CUB-CE-0104 |

## II. SUMMARY & CONCLUSIONS

**Q. Please provide a summary of your findings and conclusions.**

A. Consumers Energy Company (Consumers) filed for a rate increase of $248 million based on a test year ending October 31, 2026. I reviewed the testimony, exhibits and discovery responses and concluded that the capital expenses related to the categories described in Exhibit CUB-10 should be $ $1,022,000. It results in a reduction of $84,186,000. The proposed reductions are shown in column (d) of Exhibit CUB-10.

**Q. Please describe the history of Consumers' previous rate case filings, including requested rate increases and timing of the rate filings and Commission orders authorizing rate relief.**

A. On July 17, 2015, Consumers filed an application (U-17882) to increase rates by $84.7 million using a projected test year for the 12- month period ending December 31, 2016. On April 21, 2016, the MPSC issued an order approving a settlement agreement to increase rates by $40 million. On August 1, 2016, Consumers, in case number U-18124, filed for a rate increase of $90.5 million based on calendar year 2017 as projected test year. On July 31, 2017, the MPSC issued an order approving a rate increase of $29.2 million. Three months later, on October 31, 2017, Consumers filed for rate increase of $178.2 million in case number U-18424. On August 28, 2018, the MPSC issued an order approving the

settlement agreement reached by the parties by authorizing an annual rate increase of $10.6 million.

Three months later, on November 30, 2018,, Consumers filed for a $229 million rate increase in Case No. U-20322, based on a test year ending on September 30, 2020. On September 26, 2019, the MPSC issued an order granting authority to increase rates in the amount of $143.6 million. Three months after that, on December 16, 2019, Consumers filed for a rate increase of $245 million in Case No. U-20650 using a test year ending on September 30, 2021. On August 19, 2020, the MPSC issued an order granting authority to increase rates in the amount of $144 million by approving the settlement agreement in the case. On December 1, 2021, in case number U-21148, Consumers filed for a $278 million rate increase using a projected test year ending September 30, 2023. On July 7, 2022, the MPSC issued an order approving a settlement agreement for a rate increase of $170 million. On December 15, 2022, in Case No. U-21308, Consumers filed for a rate increase of $212 million using a projected test year ending September 30, 2024. On August 30, 2023, the MPSC issued an order approving a settlement agreement to produce additional annual revenues of $90 million.

On December 15, 2023, Consumers filed case number U-21490 for a rate increase of $136 million using a projected test year ending September 30, 2025. On July 24, 2024, the MPSC issued an order approving a settlement agreement to produce additional revenues of approximately $35 million. This was Consumers' ninth rate increase request in nine years. On December 16, 2024, exactly one year after filing its last case, Consumers filed this case requesting a rate increase of $248 million using a projected test year ending October 31, 2026.

The table below shows the rate increase history.

*Table 1*

| Filing Date | Case No. | Requested Rate Increase | Test Year | Order Date | Rate Increase |
|---|---|---|---|---|---|
| 07/15/2015 | U-17882 | $84,700,000 | 12/31/2016 | 04/21/2016 | $ 40,000,000* |
| 08/01/2016 | U-18124 | $90,500,000 | 12/31/2017 | 07/31/2017 | $29,200,000 |
| 10/31/2017 | U-18424 | $178,200,000 | 6/30/2019 | 08/18/2018 | $10,600.000* |
| 11/30/2018 | U-20322 | $229,000,000 | 9/30/2020 | 09/26/2019 | $143,600,000 |
| 12/16/2019 | U-20650 | $245,000,000 | 9/30/2021 | 08/19/2020 | $144,000,000* |
| 12/01/2021** | U-21148 | $278,000,000 | 9/30/2023 | 07/07/2022 | $170,000,000* |
| 12/15/2022 | U-21308 | $212,000,000 | 9/30/2024 | 08/30/2023 | $ 90,000,000* |
| 12/15/2023 | U-21490 | $ 136,000,000 | 9/30/2025 | 07/23/2024 | $ 35,000,000* |
| 12/16/2024 | U-21806 | $ 248,000,000 | 10/31/2026 | N/A | N/A |

* Case settled.

**Consumers did not file for an increase in 2020 because it agreed not to file until December 1, 2021, in U-20650 settlement agreement.

In recent history, Consumers has shown that it is preparing to file the next rate case during the time the current rate case is undergoing the public hearing process before the MPSC. History has shown that approximately three months after receiving a final order, Consumers files its next rate case. I am not aware of any other gas utility in Michigan filing a rate increase application each year before the completion of the test year. The utility customers who pay their bills on time every time they receive a bill from Consumers do not have the same luxury and opportunity to get increases in funds to pay for annual rate increases. The company has the unique ability to project increases year after year and get ready to pass on projected future costs to loyal ratepayers. It is my understanding that the

rate setting process is to provide a reasonable opportunity to the utility to earn a fair rate of return but not a guarantee. Consumers' use of the projected test year negates the use of complicated future forecasts of capital and O&M expenses and allows for cutting and pasting testimony and exhibits used in the previous rate case. The captive customers of Consumers will benefit more if the company executives and employees are concentrating on providing safe, efficient, and reliable utility service rather than preparing testimony and exhibits for the next rate case by updating testimony and exhibits used in the previous rate case.

The detrimental effects related to regulatory lag claimed by Consumers witnesses are minimized by its annual filings. The unregulated industry investors do not have the same luxury of filing for rate increases every year. The utility shareholders should be given an opportunity to earn a fair rate of return on their investment considering the effects of regulatory lag in a regulated industry. I believe using average of 2023 and 2024 historical data for capital and O&M expenses is appropriate for this case.

Therefore, particularly where Consumers has not supported or justified its projected test year spending, I urge the commission to use recent historical data to set rates instead of using future projected test year data the company prepares waiting for the final order in the current rate case. I am supporting the use of historical 2023 and 2024 average data for the capital expenditures and Operation and Maintenance expenditures for the test year.

**Q. Did you include any productivity and inflation related adjustments in your projections?**

A. Yes. Rick Bunch, CUB's witness presenting testimony in this case, supports a Productivity

Adjusted Total Factor Inflation (PAI) of 3.29%. My adjustments for Capital and O&M expenses include the PAI of 3.29% to account for increases for the test year.

**Q. Do you have any adjustments related to capital expenditures?**

A. Yes. Consumers projected $1.106 billion in Capital Expenditures for the categories described in Exhibit CUB-10 and I am recommending $1,022,000 be used for the test year. This results in a decrease of $84,186,000. I followed the concept of using adjusted 2023 and 2024 adjusted average amounts to reflect the test year capital expenditures.

**Q. Do you have any adjustments related to operation and maintenance (O&M) expenses?**

A. Yes. Consumers projected $228,253,000 O&M expenses for the categories described in Exhibit CUB-11 and I am recommending $205,134,000 be used for the test year. This results in a decrease of $23,119,000. I followed the concept of using adjusted 2023 and 2024 average amounts to reflect the test year O&M expenditures.

## III. CAPITAL EXPENDITURES - ADJUSTMENTS

**Q. What are your recommendations for capital expenditures related to asset relocation, regulatory compliance, capacity deliverability, distribution plant-material condition, gas operations – other, gas distribution and gas compression & storage.**

A. I will describe the following items supported by company witness Michael P. Griffin.

Asset Relocation -Transmission Program:

This program includes gas transmission replacement projects due to civic improvement projects initiated by government agencies requiring relocation. It also includes projects that

need replacement due to lack of depth of cover. Consumers estimates capital expenditures for this program to be $24,726,000 for the test year when the historical 2023 and 2024 amounts were $6,168,000 and $17,019,000, respectively. Considering the frequent nature of Consumers' rate cases, I recommend using the 2023 and2024 adjusted average of $11,975,000 for the test year.

Regulatory Compliance Program:

This program consists of four transmission programs: Pipeline Integrity Transmission Program; Pipeline Integrity Transmission Operated by Distribution (TOD) program; Cathodic Compression, Storage and Pipeline Program; Maximum Allowable Operating Pressure (MAOP) Compliance Pipeline Program.

**Q. Please describe the pipeline integrity transmission program.**

A. This program includes necessary inspections and remediations required by the federal Pipeline & Hazardous Materials Safety Administration (PHMSA) and the MPSC. Mr. Griffin's testimony explains the PHMSA regulations and the additional requirements by the MPSC. Consumers' Natural Gas Delivery Plan (NGDP), supported by witness Neil P. Dreisig, describes in detail the ten-year plan designed to achieve compliance with the federal and state pipeline safety code requirements. Mr. Griffin's testimony on Page 21 describes the capital expenditures related to the inspections and remediations conducted as part of this program.

**Q. Please describe the pipeline integrity transmission program.**

A. This program is similar to the Pipeline Integrity Transmission program conducted on pipeline segments operated on the distribution system above 20% Specified Minimum

Yield Strength. These pipelines are covered under transmission regulations. Page 22 of Mr. Griffin's testimony describes the capital expenditures for this program.

**Q. Please explain the cathodic compression, storage and pipeline capital program.**

A. This program allows the company to maintain compliance with federal safety regulations for cathodic protection of facilities. Mr. Griffin describes the capital expenditures on pages 23 and 24 of his testimony.

**Q. Please describe the MAOP compliance pipeline program and MAOP transmission program.**

A. This program deals with MAOP verification and remediation of pipeline systems required by Pipeline and Hazardous Materials Safety Administration (PHMSA) requirements to meet traceable, verifiable, and complete data criteria. Consumers conducts detailed engineering analysis to find missing data and records the findings in the company's geospatial information system database. For each pipeline segment not meeting the records criteria, the company will address the segments through a risk-based evaluation, resulting in hydrotesting, material verification or replacement. The segments with missing records would undergo destructive or nondestructive testing to attain material property values. The company testimony and exhibits provide details of planned projects to meet PHMSA requirements. These projects include capital expenditures for work involved in remediating the identified gaps. Page 27 of Mr. Griffin's testimony describes the capital expenditures for this program.

Total expenditures for the Regulatory Compliance Program were $36,139,000 in 2023 and $33,968,000 in 2024 and are projected to be $24,807,000 for the Test Year. I am supporting the adjusted average of $36,207,000 for historical years 2023 and 2024.

**Q. Please describe the capacity/deliverability program.**

**A.** Capacity-related expenditures include projects to maintain base and peak pressures and to provide inspection capabilities to meet Pipeline Integrity Program. Deliverability Program expenditures include city gate and regulator station rebuilds and improvements. Company witness Griffin's testimony, pages 30 through 50, describes details of various projects in this category. The historical expenditures in this category were $308,275,000 and $317,534,000 for 2023 and 2024, respectively. Using the reasons contained in my summary, I am proposing $323,200,000, the adjusted average of 2023 and 2024 amounts as a reasonable estimate for the test year.

**Q. Please describe capital expenditures related to gas distribution - material condition.**

A. Consumer's witness Kristine A. Pascarello supports Gas Distribution - Material condition capital expenditures. This program's expenditure is used to improve the distribution system's integrity to reduce service interruptions and to replace leaking and vintage gas distribution facilities. Enhanced Infrastructure Replacement Program (EIRP) - Distribution and Vintage Service Replacement (VSR) programs designed to replace the company's lowest performing mains. These activities are part of the company's Distribution Integrity Management Program (DIMP). The capital expenditures for the Material condition program for 2023 and 2024 were $266,297,000 and $291,158,000. The projected amount for the test year is $385,665,000. I am proposing the commission use the adjusted average

historical amounts for 2023 and 2024, $287,898,000 for the test year using the logic described in my summary.

**Q. Please describe the "gas operations other" program.**

A. This program includes expenditures related to Routine Computer and Equipment; Tools; Land and Right of Way (ROW); Compliance and Controls, and Geospatial Inventory and Modeling Program. Company witness Kristine A. Pascarello's testimony, pages 71-86 describes details of this program. The amounts for 2023 and 2024 were $7,750,000 and $12,687,000 and I included the adjusted average of $10,555,000 for the test year based on the reasons in the summary above.

**Q. What are the capital expenditures for the gas distribution projects?**

A. Company witness Lincoln D. Warriner presents testimony and exhibits in support of the Gas Distribution capital expenditures. The major programs in this category cover New Business, Asset Relocation, Regulatory Compliance, and Capacity/Deliverability. On page 7 of his testimony, he presented a summary of the actual and forecasted capital expenditures for Gas Distribution. I am recommending the adjusted average of 2023 and 2024 historical data as a projection for the test year based on the reasoning presented in my summary. The adjusted expenditures for 2023 and 2024 are $212,938,000 and $187,325,000 (Exhibit CUB-12).[1] The adjusted average of $206,716,000 should be used for the test year. 2019 to 2023 five-year historical average was $212,898. The projected test year amount of $ 321,119 ,000 is significantly larger than the 5-year average.

[1] Exhibit CUB-12, U21806-CUB-CE-0104.

Page 39 of Mr. Warriner's testimony shows the Regulatory Compliance Program capital expenditures for $34,488,000 for 2023 and $45,217,000 for 2024. The projected amount for the test year is $150,311,000 (see Table 13). He does not provide any reasons for the significant increase projected for the test year. Table 17 on page 48 shows $1,607,000 for 2023 and $9,295,000 for 2024 as MAOP Distribution sub-program capital expenditures. The projected amount for 2026 is $127,897,000 with no valid explanation. Page 39, line 4, states that the projects are required to comply with federal and state pipeline safety regulations and mandates. These regulations are not new. They were promulgated by PHMSA long time ago because of the San Bruno, California pipeline explosion on September 9, 2010. We are in 2025 and the compliance with the safety regulations is long overdue. I would request the commission to use productivity and inflation adjusted historical expenditures to set rates in this case. It gives the company a chance to complete planned projects following successful past practices.

**Q. What is your projection for gas compression & storage capital expenditures?**

A. Senior Strategy Manager Timothy K. Joyce provided testimony and exhibits related to capital expenditures for Gas Compression and Storage Assets. His exhibit A-12 (TKJ-5), Schedule B-5.7 shows the capital expenditures for 2023, 2024, and the test year. The historical amounts for 2023 and 2024 were $113,046,000 and $167,776,000, respectively. The projected test year amount is $162,039,000. I am recommending the 2023 and 2024 adjusted historical average amount of $145,031,000 for the test year.

Exhibit CUB-8 shows the capital expenditures with references to company exhibits containing the data. It includes capital expenditures for Asset Relocation; Regulatory Compliance; Capacity/Deliverability; Distribution Plant-Material Condition; Gas

Operations-Other; Distribution Plant; and Gas Compression/Storage. I am recommending the commission use the capital expenditures supported in my testimony.

Exhibit CUB-9 shows the averages of 2023 and 2024 calendar year historical capital expenditures supported by company witnesses Michael P. Griffin, Kristine A. Pascarello, Lincoln D. Warriner, and Timothy K. Joyce. As shown in the previous nine rate case histories, there is no justification in using future forecasts for setting rates when the company does not wait until the projected test-year period is completed. The company does not wait to see if the new rates are given a reasonable opportunity to earn a fair rate of return approved in the rate cases.

**Q. Can you summarize your recommended capital expenditures?**

A. Yes. Exhibit CUB-10 contains adjustments showing the difference between company forecasted amounts and the 2023 and 2024 average amounts for various programs. Column (d) shows the adjustments to forecasts used by the company witnesses for the test year. I am proposing total capital expenditure reductions of $84,186,000.

## IV. O&M EXPENSE ADJUSTMENTS

**Q. What are your recommendations for O&M expenses for gas operations, gas engineering & supply, field operations – services, gas operations-other, regulatory compliance, gas compression and gas storage O&M?**

**A.** I will describe the O&M expenses in the above-mentioned categories. I prepared Exhibit CUB-9 showing the 2023 and 2024 historical data and the adjustments I am proposing to the company forecasts.

**Q. What is the O&M expense that you are recommending for the gas operations?**

A. Consumers witness James P. Pnacek, Principal Strategy Analyst, proposed O&M expenses for the Gas Operations Division. These expenses are for Gas Operations Maintenance, and Metering; Field Operations Services; Work Management and Customer Delivery, and Operations Management. His testimony and Exhibits describe details of the O&M expenses for the four departments. Total historical expenses for these categories were $111,299,000 for 2023 and $113,000,000 for 2024. The company's projection for the test year is $133,635,000. I am recommending the adjusted average of 2023 and 2024 annual amounts, which is $115,840,000. My recommendation is based on the concept of using the two-year historical average described in my summary and conclusions.

**Q. Did Consumers include projected O&M expenses for anticipated new PHMSA pipeline safety rules?**

A. Yes. On page 8 of James P. Pnacek's testimony, he describes PHMSA's proposed regulatory amendments related to Leak Detection and Repair (LDAR) rules. The new rules were expected to be published by January 2025 with an expected compliance date of January 2026. The company included $1,300,000 to account for the proposed LDAR requirements in this case. The new administration at the federal level put on hold any new requirements of PHMSA gas safety regulations. The proposed spending to comply with the amended LDAR rules is premature and my proposal for using 2023 and 2024 average O&M expenses would result in not including new proposed gas safety regulation expenses in this case.

**Q. What are the O&M expenses for gas engineering and supply?**

A. The O&M expenses for the Gas Engineering and Supply area is supported by company witness Kristine A. Pascarello, Senior Strategy Manager, in the Gas Strategy Department within Gas Engineering and Supply. She forecasted $22,195,000 for this item. The historical 2023 and 2024 O&M expenses for this area were $16,014,000 and $19,225,000, respectively. Following the two-year average concept described earlier in my summary and conclusions, I am recommending the 2023 and 2024 adjusted average amount of $18,200,000 for the O&M expenses for the projected test year.

**Q. What is the O&M expense for the category gas operations - other?**

A. Company witness James P Pnacek explains and supports the O&M expenses for Gas Operations – Other. This item reflects O&M expenses for Compliance and controls; Work Management and Customer Delivery; and Operations Management. Actual expenses for 2023 and 2024 were $5,892,000 and $4,021,000. Company forecast for the test year is $4,207,000. Following the concepts described in my testimony, I am supporting the 2023 and 2024 adjusted average of $5,120,000.

**Q. What are the O&M expenses for the regulatory compliance program**?

A. Michael P. Griffin, Senior Strategy Manager, in the Gas Strategy Department supports the O&M expenses for this category. The O&M expenses are related to Pipeline Integrity Transmission; Pipeline Integrity (TOD) Program; Corrosion control Transmission and MAOP Transmission. His exhibit A-58 (MPG-1) supports $20,034,000 for 2023 and $23,527,000 for 2024 with a projection of $23,129,000 for the test year. I am supporting the adjusted average of 2023 and 2024 amounts, $22,498,000 as the test year projection.

**Q. What are the O&M expenses for gas compression and storage?**

A. Senior Strategy Manager Timothy K. Joyce supports O&M costs for this category. These expenses relate to fuel, oil and glycol for equipment and vehicles, materials, tools, cleaning supplies security and road and grounds maintenance. His exhibit A-80 (TKJ-1) shows the historical totals for 2023 and 2024, $17,880,000 and $17,030,000. In response to discovery, the company supplied $17,142,000 as the actual 2024 amount. The test year's forecast is $17,577,000. I am recommending the adjusted two-year average of $18,087,000 for the test year using the method supported in my summary and conclusions.

**Q. What are the O&M expenses for gas storage?**

A. Principal Strategy Analyst James P. Pnacek supports O&M costs for this category. These costs are associated with safe operation of gas storage system including 15 gas storage fields, 808 gas storage wells and 244 miles of gathering lines. The O&M tasks include valve and operator inspections, line patrol and leak survey, integrity monitoring, inspection and maintenance of regulators and relief valves, surface and surface safety valves, isolation valves, fluid separators and fluid separation systems. His testimony, on page 72, Table 51 shows the historical totals for 2023 and projected 2024, $5,739,000 and $5,356,000. In response to discovery, the company supplied $5,548,000 as the actual 2024 amount. The test year forecast is $5,473,000. I am recommending the adjusted two-year average of 5,731,000 for the test year using the method supported in my summary and conclusions.

**Q. What is your recommendation for the O&M expenses presented in this case?**

**A.** Exhibit CUB-9 shows 2023 and 2024 calendar year historical O&M expenses supported by company witnesses James P. Pnacek, Kristine A. Pascarello, Michael P. Griffin, and

Timothy K. Joyce. Company exhibit references are shown in Exhibit CUB-9. I would urge the commission to use 2023 and 2024 historical actual O&M expenses with inflation adjustment as a representation of expected levels for the test year ending on October 31, 2026.

**Q. What are your recommendations for the O&M expense levels for the test year?**

A. Exhibit CUB-11 shows the reductions and increases in the O&M expenses for various categories. Column (d) shows the adjustments to the company proposals totaling a decrease of $23,119,000. I used 2023 and 2024 adjusted average historical data for the test year.

## V. CONCLUSION

**Q. Please summarize your conclusions for the Commission.**

The proposed rate increase is significant and is extremely burdensome for residential ratepayers considering current economic conditions. I urge the commission to consider the current economic disruptions experienced by ratepayers in considering the significant rate increase proposed by Consumers. We are in April of 2025, and I expect that Consumers is preparing testimony and exhibits for the next rate case filing with projections of future projects containing larger capital and O&M expenses. The cycle never ends if the MPSC approves even a small portion of the requested increase. Consumers has the responsibility to provide safe and reliable utility service because they have long-term franchises to provide gas service. No other gas utility can provide service in competition because Consumers is the only one who has mains and services connected to the customer piping. I urge the commission to consider the franchise limitations and loyal customers' inability to look for other sources of gas. I request the commission use average historical data for

2023 and 2024 (adjusted for inflation and productivity) for capital and O&M expenses as a proxy for test year ending on October 31, 2026.

**Q. Does that complete your testimony?**

A. Yes.

MS. HILLYER: Next, at this time, I move to bind into the record the prefiled direct testimony of Matthew Bandyk, which consists of a cover page, table of contents, and 33 pages of questions and answers. And I also move for the admission of Mr. Vandyk's exhibits, which consist of Exhibits CUB-13 through CUB-20.

JUDGE VARCHETTI: All right. Any objections to the admission of the direct testimony of Mr. Bandyk or the associated exhibits?

I am hearing none, so the testimony is bound into the record, and the exhibits are admitted.

MS. HILLYER: Thank you, Your Honor.

(Direct Testimony bound in)

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

| | |
|---|---|
| In the matter of the application of **CONSUMERS ENERGY COMPANY** for authority to increase its rates for authority to increase its rates for the distribution of natural gas and for other relief. | U-21806 |

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# DIRECT TESTIMONY OF MATTHEW BANDYK

## ON BEHALF OF

## CITIZENS UTILITY BOARD OF MICHIGAN

**April 23, 2025**

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**DIRECT TESTIMONY OF MATTHEW BANDYK FOR CUB**
**CASE NO. U-21806**

## I. INTRODUCTION AND QUALIFICATIONS

**Q Please state your name, business address, and position.**

A My name is Matthew Bandyk. I am a Principal Associate at Synapse Energy Economics Inc., located at 485 Massachusetts Ave, Suite 3, Cambridge, Mass., 02139.

**Q Please describe Synapse Energy Economics.**

A Synapse Energy Economics is a research and consulting firm specializing in energy industry regulation, planning, and analysis. Synapse works for a variety of clients, with an emphasis on consumer advocates, regulatory commissions, and environmental advocates.

**Q Please describe your professional experience before beginning your current position at Synapse Energy Economics.**

A I was previously a consultant at 5 Lakes Energy, a Michigan-based energy policy consulting firm. My experience is summarized in my resume, attached as Exhibit CUB-13.

**Q Have you previously testified before the Michigan Public Service Commission?**

A Yes. I have previously testified before the Michigan Public Service Commission (Commission) in the following cases:



VERITEXT LEGAL SOLUTIONS

- **Case No. U-21585 (Consumers Energy Electric rate case);**
- **Case No. U-21534 (DTE Electric rate case);**
- **Case No. U-21555 (UPPCO Rate case);**
- **Case No. U-21540 (Michigan Gas Utilities Rate case);**
- **Case No. U-21490 (Consumers Energy Gas Rate case);**
- **Case No. U-21389 (Consumers Energy Electric Rate case);**
- **Case No. U-21048 (Consumers Energy 2022 PSCR Plan case); and**
- **Case No. U-21291 (DTE Energy Gas Rate case).**

**Q What is the purpose of your testimony?**

**A** The purpose of my testimony is to give a recommendation on the overall rate of return the Commission should approve in this case.

**Q Are you sponsoring any exhibits?**

**A** Yes, I am sponsoring the following exhibits:

- Exhibit CUB-13: Resume of Matthew Bandyk
- Exhibit CUB-14: Cost of Capital
- Exhibit CUB-15: CAPM Analysis
- Exhibit CUB-16: Equity Risk Premium
- Exhibit CUB-17: Beta
- Exhibit CUB-18: DCF Analysis
- Exhibit CUB-19: Long-Term Growth Rates
- Exhibit CUB-20: Bulkley Testimony from Wisconsin Public Service Corporation Case

## II. SUMMARY OF CONCLUSIONS AND RECOMMENDATIONS

**Q Please summarize your primary recommendations.**

A I recommend that the Commission approve a return on equity of 9.24% for Consumers Gas. Based on a capital structure of 50.75% equity and 49.1% debt and a cost of long-term debt of 4.35%, this return on equity results in an overall rate of return of 5.79%.

## III. COST OF CAPITAL - PRINCIPLES

**Q Please explain the concept of cost of capital and its significance.**

A The cost of capital is the return demanded by investors on the capital they supply to the Company.[1] It is the weighted average of the costs of the various classes of capital supplied by investors — in this case, debt and equity. The cost of debt and cost of equity are each weighted by the respective amounts of debt and equity in the Company's total capital structure, so the ratio of equity to debt is another important component of the cost of capital. The cost of debt can be relatively easily observed through the interest rates lenders demand on debt issued by the Company. The cost of equity, however, is the product of market expectations that can only be estimated by looking at a number of factors.

Estimating the cost of equity for a regulated utility must be done carefully so as to arrive at a return that ensures rates that are "just and reasonable," a principle elaborated on in the landmark U.S. Supreme Court cases that set the legal standards

[1] Roger A, Morin, PhD. Modern Regulatory Finance. PUR Books, 2021, p. 27.

governing public utility regulation, *Bluefield Water Works & Improvement Co. v. Public Service Commission of West Virginia* and *Federal Power Commission v. Hope Natural Gas Co*.

For example, in *Hope*, the Court said that the "just and reasonable" standard implies that "the return to the equity owner should be commensurate with returns on investments in other enterprises having corresponding risks. That return, moreover, should be sufficient to assure confidence in the financial integrity of the enterprise, so as to maintain its credit and to attract capital."[2]

But the Court was also clear that the determination of what return is "sufficient" in that regard must also involve a consideration of the interests of the company's customers. Indeed, just as a return for a utility that is set below the amount "commensurate with returns on investments in other enterprises having corresponding risks" causes the utility to lose wealth relative to what it should earn with a more appropriate return, a return that is set above this amount will cause the utility's customers to be overcharged and lose wealth relative to what they would be charged with a lower and more appropriate return. In this latter case, that wealth is instead transferred from customers to the utility holding company's shareholders.

**Q What methods may be employed to determine the cost of capital?**

**A** In *Hope*, the Supreme Court held that it is the result reached, not the method employed, which is controlling, and that result should be a rate that people would reasonably consider to be commensurate with the risk of the investment. In practice,

[2] *Fed Power Com v Hope Natural Gas Co*, 320 US 591, 603 (1944).

reaching that result involves using methods that are widely accepted in the financial community to estimate investor perceptions of risk. I rely on these methods in my testimony to estimate the Company's return on equity (ROE).

**Q How have public regulatory commissions historically fared at estimating returns on equity for utilities that are commensurate with risk?**

A There is strong evidence from multiple observers and peer-reviewed academic research that public regulatory commissions on average have tended to set electric utility ROEs above what economists would arrive at using the widely-accepted methods for estimating ROE. I will describe this ROE that regulatory commissions tend to exceed as a "market-based ROE" since it is estimated using methods that gauge how the market rates the risk of a utility investment. Commissions approving ROEs that exceed a market-based ROE has resulted in a transfer of wealth from ratepayers to shareholders.

Arriving at an ROE is a process of estimation, and that process will invariably include some degree of subjectivity. Subjective factors can influence any human decision-making process, including the decisions of public regulatory commissions, and lead to unintended results. These factors include the influence of utilities in the regulatory process. Utilities often have more resources to make their case heard for why ROE should be higher than opposing groups do, even if the utilities' arguments are not necessarily stronger.

Academics have also noted the phenomenon of a growing premium of regulatory commission-awarded ROEs over the rate of return on long-term U.S. Treasury bonds (the risk-free rate), and research has found that this premium cannot

statistically be explained by financial fundamentals, such as a change in the equity or debt risk of the utilities in question.[3] This premium costs consumers because it ensures that utilities collect a greater return from consumers than would be justified by a market-based ROE. A 2023 paper published by the Energy Institute at the University of California Berkeley's Haas School of Business found that the cost to consumers from rates of return for electric and gas utilities that are set above a market-based return costs U.S. consumers around $7 billion per year.[4]

Experts including utility attorney Steve Huntoon have also examined the record of authorized ROEs and found that regulators tend to set ROEs above returns of investments that are riskier than utilities, indicating that regulatory decisions are not in line with the economic reality that lower risk means lower return.[5]

A higher return implies higher risk, so approving ROEs that are higher than market returns would imply that regulated utilities are riskier investments than the market as a whole. But they are not. Regulated utility returns tend to be less risky than the market as a whole, as demonstrated by the betas of regulated utility holding companies. Beta is a measurement of the sensitivity of a stock's returns relative to those of the market as a whole. Utility holding company betas tend to be less than

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[3] "This growing premium does not appear to be explained by traditional asset-pricing models, often in direct contrast to regulators' stated intent… However, absent some normative justification for this premium, it would appear that regulators are authorizing excessive returns on equity to utility investors and that these excess returns translate into tangible profits for utility firms." David Rode and Paul Fischbeck. "Regulated equity returns: A puzzle." Energy Policy, Oct. 2019. Available at https://www.sciencedirect.com/science/article/abs/pii/S0301421519304690?via%3Dihub

[4] Karl Dunkle Werner and Stephen Jarvis. "Rate of Return Regulation Revisited." Energy Institute at Haas Working Paper 329R. Revised September 2024. Available at https://haas.berkeley.edu/wp-content/uploads/WP329.pdf

[5] Steve Huntoon. "Nice Work If You Can Get It." Fortnightly Magazine, August 2016. Available at https://www.fortnightly.com/fortnightly/2016/08/nice-work-if-you-can-get-it.

one, meaning that those stocks are less sensitive to changes in overall market returns.

**Q If regulated utilities are less risky than the market, then why have regulated utilities historically been awarded ROEs above market returns?**

A The remaining explanation is that public regulatory commissions have tended to accept estimates for ROE that are above fair, market-based ROE estimates.

**Q What ROE is Consumers Energy recommending in this case?**

A In this case, supported by testimony from Witness Bulkley, Consumers Energy is proposing an ROE of 10.25%, an increase from its current authorized ROE of 9.9%.

**Q Does this evidence for ROEs being generally set too high relative to cost of equity show that Ms. Bulkley's recommended ROE is not commensurate with risk?**

A Not by itself, no. One must still turn to financial models to form a quantitative basis for the company's cost of capital. But the history of inflated ROEs is a reason to enter this exercise with an informed presumption that Consumers Energy's proposed ROE is likely to be well above its cost of equity, and the burden is on the Company to prove otherwise. In my opinion, Ms. Bulkley has failed to do so.

In other words, the reasons listed above are reasons to *suspect* that the proposed ROE is too high. But the quantitative analysis from applying financial models *confirms* that suspicion.

**Q Is Ms. Bulkley's recommended ROE of 10.25% a return commensurate with risk?**

A No. Ms. Bulkley's recommended ROE is inflated above what would be a fair return due to several overestimated inputs into her discounted cash flow (DCF) and capital asset pricing model (CAPM) analyses, as well as her methodologically-flawed application of a bond yield risk premium (BYRP) analysis.

**Q Ms. Bulkley claims that "the authorized ROE and equity ratio for regulated utilities is very important for determining the degree of regulatory support for reinforcing a utility's creditworthiness and financial stability in the jurisdiction."[6] Do you agree that "reinforcing a utility's creditworthiness and financial stability" should be a goal of the MPSC in this proceeding?**

A No. The Company is not entitled to a particular level of "financial stability" – only that its return be sufficient to assure confidence in its financial integrity, per *Hope*. The distinction between "financial stability" and "financial integrity" is an important one. If the utility were entitled to a specific level of financial stability, that could imply that its ROE should never be reduced, since doing so would introduce instability. But a return sufficient to maintain "financial integrity" only implies that the utility be able to attract capital – not that it can attract capital on the terms that it currently does. A utility can still attract capital with a lower ROE. For example, if a lower ROE causes the stock price to drop, that lower price will attract new investors.

[6] Direct Testimony of Company Witness Ann E. Bulkley p. 9, at 5-7.

**Q Similarly, Mr. Bleckman testifies that recent MPSC decisions on ROE have caused Michigan to slide in analyst rankings of "regulatory environment," and argues against further "degradations" of ROE because "Michigan's above average regulatory standing needs to be protected and bolstered."[7] Do you agree?**

A No. The commission should not take rankings of "regulatory environment" into account when deciding where to set ROE. These rankings by UBS and S&P appear to be judgments for how generous utility commissions tend to be with the ROEs they tend to grant utilities. The rankings have nothing to do with the critical question of whether or not the commissions are properly arriving at returns commensurate with the risks of the underlying utilities. No doubt Consumers' current shareholders want a return as high as possible. But one should not confuse desire with risk. The "just and reasonable" standard from *Bluefield* and *Hope* does not entitle a utility to its current level of cost of capital. The language of *Hope* is that a "just and reasonable" return is one "commensurate with risk," and that return may be one below its current level of cost of capital. Indeed, as I described above, there is strong support for the proposition that public regulatory commissions consistently set ROEs too high, resulting in costs of capital for utilities that are too high. For those utilities, the current level itself is not "just and reasonable."

[7] Direct Testimony of Company Witness of Marc R. Bleckman p. 21, at 5-7.

**Q Would Consumers Energy customers pay for an excessive return if the MPSC approves Ms. Bulkley's proposed ROE in this case?**

A Yes. The ROE is a component of the overall rate of return along with the cost of debt. If the MPSC were to approve the utility's request for a rate increase without changes, Consumers would collect about $730.85 million from customers for a return on its rate base, based on an overall rate of return of 6.22%[8] and a total jurisdictional rate base of $11.75 billion.[9] If the ROE were instead the market-based ROE of 9.24% that I am recommending in this case, that overall rate of return would fall to 5.79%[10], and so the amount collected would fall from $730.85 million to $680.33 million, resulting in savings to customers of about $50.53 million on an annualized basis.

**Q Does Consumers Energy acknowledge that an excessive return is detrimental to ratepayers?**

A No. Mr. Bleckman attempts to argue that the Company's current ROE is actually leading to ratepayer savings by bolstering the Company's credit rating and leading to lower interest costs.[11]

Exhibit A-35 (MRB-13) shows the sum of the spread between the interest costs from the S&P rating on CMS Energy (CMS) senior secured debt in a given year and the interest costs if the rating were BBB-. The sum is $153 million in

[8] Exhibit A-14 (MRB-1), Sched. D-1.

[9] Exhibit A-12 (HLR-31), Sched. B-1.

[10] See Exhibit CUB-14.

[11] Bleckman, p. 18, lines 13-14.

"cumulative annual interest savings" from 2007 to 2024, or $9 million on an annualized basis. Those "savings" are $41.5 million less than the $50.53 million in costs per year that customers would pay for the excessive ROE in this case. Clearly, Consumers Energy's high ROE is more financially detrimental to ratepayers than any potential interest cost savings cited by the Company.

In addition, the Company has not shown that CMS's debt rating would have fallen to BBB- if the Company had been awarded an ROE or equity-debt ratio below its actual awarded ROE in those years, nor does any witness show that such a rating would follow this case if the Commission approved an ROE below the Company's recommended range in this case.

## IV. COST OF CAPITAL – METHODS

***Summary***

**Q What quantitative methods did you use to estimate the utility's ROE?**

**A** As I stated earlier in my testimony, arriving at an ROE commensurate with risk requires the use of the methods that are widely accepted in the financial community to estimate investor perceptions of risk. My ROE estimate is based on the Capital Asset Pricing Model (CAPM) and the Discounted Cash Flow (DCF) methods, which are widely accepted methods for calculating ROE. These are also two of the methods used by Ms. Bulkley to develop her recommended ROE. I did not, however, use two of the methods she used, for reasons I will explain. These two are the Empirical Capital Asset Pricing Model (ECAPM) and the BYRP analysis.

**Q Please summarize your ROE recommendation.**

**A** The results of my DCF and CAPM analyses and my resulting recommendation for the utility's ROE in this case are below:

| | |
|---|---|
| CAPM | 7.95% |
| DCF | 9.22% |
| Average of CAPM and DCF | 8.58% |
| Consumers Energy current ROE | 9.9% |
| **Recommendation** | **9.24%** |

**Q Why are you recommending an ROE that is higher than any of the results found in your financial models?**

**A** The average of my model results suggests that an ROE lower than 9.24% would be a market-based cost of equity for Consumers Energy. But Consumers Energy is not a competitive business solely answerable to market forces. Any significant changes in Consumers Energy's ROE should be implemented gradually so as not to create unnecessary instability in the company's market value, which to some degree reflects the outcomes of regulatory proceedings like this one.

To account for modeling uncertainty and this principle of gradualism, my final recommendation represents the midpoint between the average result of my models and the 9.9% ROE awarded to Consumers Energy in its last gas rate case (U-21490).

*CAPM & ECAPM*

**Q Please describe your application of the CAPM to estimate the ROE.**

A I provide my CAPM estimate in Exhibit CUB-15.

Ms. Bulkley's use of the CAPM formula is for the most part noncontroversial, and my CAPM analysis follows the same basic formula. The numbers we use for several important inputs to the formula – the equity risk premium (ERP), beta and the risk-free rate – differ, for reasons I explain below.

**Q Please explain how you arrived at the ERP used in your CAPM formula.**

A The ERP is an essential component of the CAPM formula. It represents the excess return an investor would receive over the risk-free rate by investing in the broader equity market. The ERP is calculated as the estimated return on the market an investor can expect from investing in the broad stock market minus the risk-free rate.

It is important when estimating the ERP to not be overly reliant on historical data. While historical estimates of ERP are commonly used by the financial community, that popularity does not make them less flawed. As New York University Stern School of Business Professor Aswath Damodaran, one of the most highly respected and widely cited experts in finance and valuation, has written:

Given how widely the historical risk premium approach is used, it is surprising how flawed it is and how little attention these flaws have received.[12]

[12] Aswath Damodaran, "Estimating Equity Risk Premiums," Stern School of Business, accessed March 2025, available at https://pages.stern.nyu.edu/~adamodar/pdfiles/papers/riskprem.pdf.

There are two main reasons for the flaw with this methodology. First, the historical estimate for ERP is extremely sensitive to the historical time period selected, meaning that the subjective judgment by the person deciding which time period to collect market data for has an outsized impact on the result.[13]

Second, regardless of the time period selected, historical estimates of ERP are subject to the problem of survivorship bias, where returns that go into historical ERPs tend to be those from stocks that remain in the market, rather than those that drop out. This survivorship bias effect tends to inflate historical ERPs.[14]

**Q Are there any methods of estimating ERP not subject to these problems?**

**A** Yes. Dr. Damodaran suggests using an "implied equity risk premium" method:

The advantage of this approach is that it is market-driven and current, and does not require any historical data. Thus, it can be used to estimate implied equity premiums in any market.[15]

This approach values stocks in a market at the present value of dividends from each stock growing at a constant rate. Essentially, Dr. Damodaran takes the same discounted cash flow model Ms. Bulkley and I use to estimate the cost of equity for a single company and applies it to value the expected return of a broad market

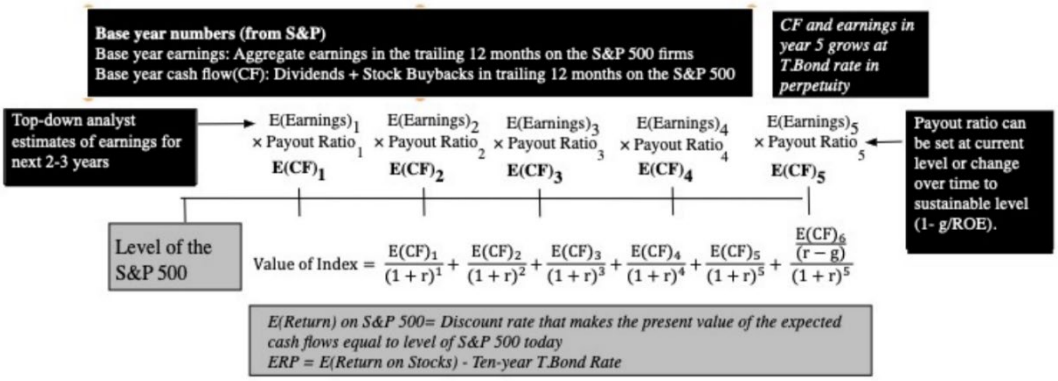
[13] *Id.* "…the risk premium estimated in the US markets by different investment banks, consultants and corporations range from 4% at the lower end to 12% at the upper end… In summary, the risk premium estimates vary across users because of differences in time periods used, the choice of treasury bills or bonds as the risk-free rate and the use of arithmetic as opposed to geometric averages."

[14] *Id.* "…the survivor bias will result in historical premiums that are larger than expected premiums for markets like the United States, even assuming that investors are rational and factor risk into prices."

[15] *Id.*

index, the S&P 500. Dr. Damodaran's formula, summarized in the figure below, begins with the base level of aggregate earnings of the S&P 500 index, and then applies the basic assumption of the discounted cash flow model that the present value of an asset is the stream of cash flows it is expected to generate, with each cash flow discounted at a rate that reflects the time value of money.

**Fig. 1**[16]




In Dr. Damodaran's approach, the cash flows are the earnings from dividends and stock buybacks that stocks in the S&P 500 generate, assumed to grow for five years at a rate derived from analyst growth forecasts, and then slowing to a perpetual growth rate that is equal to the risk-free rate. He then algebraically calculates the discount rate that allows these future cash flows to equal the current level of the index, resulting in a rate that reflects the return that investors require to invest in the market. Subtracting the risk-free rate from that required return results in the ERP.

[16] Reproduced from Damodaran, "Estimating Equity Risk Premiums," p. 94.

Dr. Damodaran regularly publishes five estimates of the U.S. ERP based on this implied equity premium approach. The estimates are based on different assumptions, such as normalizing earnings by replacing the base year earnings with the average earnings yield over the last decade. For my ERP,[17] I use the average of a) all five different estimates for ERP from Dr. Damodaran calculated in September 2024 and b) ERP estimates from two other sources. My first other source is the average U.S. market risk premium identified by the 2023 IESE Business School survey of thousands of finance and economics professors, analysts and managers of companies. While described as a "market risk premium," this number indicates the equity risk premium for the U.S. market.[18] Second, I used the recommended U.S. ERP from financial research firm Kroll for 2025.[19] Kroll's recommended U.S. ERP is based on risk perceptions in the market and other qualitative and quantitative inputs, such as an implied equity risk premium model.

**Q Is the ERP you calculate forward-looking to account for the fact that Consumers Energy's test year is in the future?**

A Yes. Dr. Damodaran's ERP is purposely calculated to be forward-looking in order to avoid the aforementioned pitfalls with historical approaches for ERP.[20] More

[17] See Exhibit CUB-16.

[18] Pablo Fernandez, Teresa García De Santos and Javier Fernandez Acin. "Survey: Market Risk Premium and Risk-Free Rate used for 96 countries in 2024," March 10, 2024. Available at SSRN: https://papers.ssrn.com/sol3/papers.cfm?abstract_id=4754347.

[19] Kroll, "Kroll Lowers its Recommended U.S. Equity Risk Premium to 5.0%, Effective June 5, 2024," June 6, 2024. https://media-cdn.kroll.com/jssmedia/kroll-images/pdfs/kroll-lowers-its-recommended-us-equity-risk-premium-effective-june-5-2024.pdf?_ga=2.111398599.2140960630.1741375312-1534596282.1741375312

[20] "The implied ERP is computed by using expected cash flows in the future, and what investors are paying for those cash flows today, making them forward looking." Damodaran, p. 93.

specifically, Dr. Damodaran calculates the ERP using an expected growth rate for payouts to investors (i.e., dividends and stock buybacks) that is the average of two-year growth forecasts of the aggregate earnings of the S&P 500 Index from analysts from Thomson Reuters, Factset, Yardeni and S&P Capital IQ.

**Q Does Ms. Bulkley calculate the ERP she uses for her CAPM analysis using the same method as Dr. Damodaran?**

A No. While she describes her equity risk premium as an "implied expected equity risk premium,"[21] Ms. Bulkley uses a very different methodology. Her expected return on the market is the addition of a) a Bloomberg forecast of the three- to five-year growth rate for earnings per share of companies in the S&P 500 Index and b) a Bloomberg estimate of the dividend yield of companies in the S&P 500 Index. This formula, where (cost of equity) = expected dividend yield plus *g* [growth rate], is essentially a simplified version of the discounted cash flow formula used by Dr. Damodaran and many others.

**Q Why is Ms. Bulkley's ERP estimate so much higher than yours?**

A Ms. Bulkley has used an inflated estimate for *g*, and the consequence of that choice is amplified by her use of a more simplified discounted cash flow, which makes her result much more sensitive to the level at which *g* is set because *g* is only one of two inputs to her formula (the other input being the dividend yield). As I described above, Dr. Damodaran's approach assumes cash flows will grow for five years at an analyst-forecasted rate, then assumes that growth will settle at a more sustainable

[21] Bulkley, p. 27.

long-term rate based on the risk-free rate. But Ms. Bulkley's approach assumes that cash flows will grow in the long term at a constant 10.45%[22] rate based on analyst expectations of the next three to five years. It is unrealistic to assume that dividends can grow in perpetuity at such a high rate, and Dr. Damodaran's assumption that growth will settle to a more sustainable rate is much more appropriate for a realistic application of the discounted cash flow model. This problem with Ms. Bulkley's approach will surface again when I discuss her DCF analysis for ROE.

In addition, Ms. Bulkley relies on just one source for her long-term growth rate: Bloomberg. Contrast that with Dr. Damodaran's estimate for the cash flow growth rate that is an average of forecasts from four different sources. His resulting expected growth rate for the ERP estimates I use is 8.82%, a result that is much more conservative than Ms. Bulkley's 10.45%. Ms. Bulkley's reliance on one source contributes to her inflated ERP estimate.

**Q Explain how you arrived at the beta used in your CAPM formula.**

**A** The beta coefficient is a measure of the sensitivity of a company's returns to the returns of the market as a whole – how much the historical returns mathematically vary compared to the variance of the historical returns of the market. Its relevance for the CAPM formula is that it measures the risk associated with investing in the company's equity that cannot be eliminated through portfolio diversification. In theory, an investor can buy other stocks in the market to compensate for the risk of any one stock, but if that stock's returns are heavily correlated with the returns of

[22] Exhibit A-14 (AEB-1), Sched. D-5, p. 16.

the market, the investor is essentially not diversifying away the stock's risk because it is merely adding more of the same kind of risk. Thus, beta is often described as a measure of "systematic risk" – the financial risk of a company that is not the result of risks from the company itself, but from its performance relative to the market as a whole (the "system").

While calculating beta for publicly-traded stocks is fairly straightforward due to the availability of plentiful data on a stock's performance relative to the market, even a company that is not publicly traded, such as Consumers Energy, carries systematic risk vis-à-vis the market that can be calculated as a beta coefficient.

I use the average of two beta coefficients in my CAPM formula: First, the average of the Value Line beta estimates for the companies in Ms. Bulkley's proxy group, and second, the average of the Bloomberg beta estimates for the companies in her proxy group. But for each of these two betas, I make an important adjustment that makes the beta coefficient more accurate.

**Q Please explain the adjustment you made to beta.**

**A** To be more precise, as shown in Exhibit CUB-17, I remove an adjustment that has been made to the Bloomberg and Value Line betas by those data sources. Bloomberg and Value Line report "adjusted" betas rather than "raw" betas. Raw betas are converted into adjusted betas through the commonly used "Blume adjustment" equation that is meant to remove the bias that stems from the long-run tendency of betas to regress to 1. For stocks in most industries, this tendency of

betas is thought to be a result of efforts by management to keep the systematic risk of a given firm close to that of the market.[23]

But this assumption that betas revert to the mean does not hold when it comes to the betas of rate-regulated utilities. The ability to recover costs inoculates rate-regulated utilities from systematic risk. Rate regulation protects investor-owned utilities like Consumers from the risks of rising expenses, commodity price risk and competitive risks, and they enjoy natural monopolies that mitigate market risks associated with the customer base. As a result, the Blume adjustment is not appropriate to apply to the betas of companies like those in the Company's proxy group.

There is extensive academic literature supporting the inapplicability of the Blume adjustment when it comes to utilities. The theoretical argument that the unique characteristics of rate regulation reduce systematic risk for utility stocks is well-supported. Utility stock performance tends to be countercyclical, so betas tend to be less than 1.[24]

There is a strong empirical record in the academic literature showing that rate-regulated utility stock betas in practice do not revert to 1. An empirical analysis of the monthly returns of stocks of 57 publicly-traded electric and gas utilities from

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[23] Michelfelder, "Public Utility Beta Adjustment and Biased Costs of Capital in Public Utility RateProceedings" The Electricity Journal, 2013. https://www.sciencedirect.com/science/article/abs/pii/S1040619013002340

[24] "We note that it has been pointed out in the finance literature that applying the Blume adjustment can cause (rather than remedy) bias, particularly when being applied to industries where a beta of below or above unity is expected." Allen Consulting Group, "Empirical evidence on proxy beta values for regulated gas distribution activities," June 2007. https://www.aemc.gov.au/sites/default/files/content/3016ea51-04c4-4b64-890c-845d23d2c47d/Annexure-C-Empirical-Evidence-on-Proxy-Betas.pdf

1962 to 2007 found that the mean and median betas decline over time, rather than rise to 1, as the Blume adjustment to beta assumes.[25]

**Q Why did you not use the ECAPM?**

**A** To my knowledge, the Commission has never recognized the ECAPM as a valid methodology for estimating ROE.[26] The MPSC Staff has also historically declined to use the ECAPM model as part of its ROE analyses.[27]

***DCF***

**Q Please explain your application of the Discounted Cash Flow (DCF) model to estimate the Company's cost of equity.**

**A** I add the Company's growth rate, or (g), to the dividend yields of each company in Ms. Bulkley's preferred proxy group to arrive at an estimated cost of equity. My DCF result is lower than Ms. Bulkley's primarily due to the lower estimate I use for the growth rate. Selecting the growth rate may be the most important element of the DCF analysis.

[25] These results "strongly refute the validity of the Blume equation for public utility stocks." Michelfelder 2013.

[26] Case No. U-21389, PFD, December 21, 2023, p 337 ("This PFD notes that Consumers has not identified an order wherein the Commission has recognized let alone adopted the use of the ECAPM model, and this ALJ is unaware of any."); *see also* Case No. U-21585, PFD, January 27, 2025, p 341 ("The Company failed to identify any order in which the Commission recognized this approach, and for the reasons identified by Staff and the other intervenors, this PFD is not persuaded that the ECAPM approach is reliable or reasonable.").

[27] *See, e.g.*, Case No. U-20940, Direct Testimony of MPSC Staff Witness Joseph Ufolla, 5 TR 1869, lines 9-16.

**Q Why is the growth rate you have selected superior to that selected by Ms. Bulkley?**

A The EPS projections used by Ms. Bulkley are all in the short term: three- to five-year consensus analyst dividend per share growth estimates. But a short-term growth rate cannot be the only growth rate used in the DCF model.

The use of only short-term rates for perpetual growth leads to a wildly unrealistic outcome. A DCF growth rate input higher than the growth rate of the economy as a whole implies that, in the long run, the Company will grow larger than the entire U.S. economy. Such an outcome is impossible.[28]

**Q Explain how you selected the *g* you use in your DCF model.**

A My DCF analysis is presented in Exhibit CUB-18. I use a two-stage DCF model that includes a weighted average of a short-term growth rate based on investor expectations of utility earnings growth and a long-term growth rate that matches investor expectations of the growth of the domestic economy as a whole. The formula for this model is essentially the same as that in the model used by Ms. Bulkley: ke = (D1/P0) + g.

But whereas in Ms. Bulkley's model, (*g*) is merely the short-term earnings projection, in the two-stage model (*g*) is a composite of the short-term projection and the long-term growth rate that represents the proper bound for Consumers

[28] Aswath Damodaran. *Investment Valuation: Tools and Techniques for Determining the Value of Any Asset*, 3rd ed. John Wiley & Sons, Inc, 2012 ("If a firm is a purely domestic company, either because of internal constraints . . . or external constraints (such as those imposed by a government), the growth rate in the domestic economy will be the limiting value.")

Energy's long-term growth, reflecting that in the long term Consumers Energy cannot grow larger than the domestic economy of which it is a part. The reason for this two-step process is that short-term and long-term growth often differ and failing to account for those differences leads to an incorrect application of the DCF model.[29]

My method follows FERC's approved methodology used to analyze the base ROE of a public utility's rates under the Federal Power Act using the DCF model. FERC has endorsed a two-step model in which the short-term growth rate is weighed at 80% and the long-term growth rate is weighed at 20%.[30] I use those same weightings in my model. Specifically, I weighed the short-term growth rates for each proxy group company from Exhibit A-14 (AEB-1), Schedule D-5, page 3 at 80%, and the long-term growth rate at 20%.

Candidates for long-term growth rates are listed in Exhibit CUB-19, and they each represent conservative estimates of long-term economic growth. I select the highest of these candidates, the nominal GDP growth rate from 2028 to 2035, as the value for the long-term (g) used in the DCF formula.

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[29] "The standard DCF model would be incorrectly specified when the investors' expected intermediate term EPS growth rate differs from the long-term sustainable EPS growth rate." Morin, p. 385.

[30] Stephen M. Spina, J. Daniel Skees and Patrick R. Pennella. "FERC Revises Methodology to Evaluate Return on Equity (Again)." Morgan Lewis, June 2, 2020, available at https://www.morganlewis.com/blogs/powerandpipes/2020/06/ferc-revises-methodology-to-evaluate-return-on-equity-again.

**Q How else does your DCF model differ from Ms. Bulkley's?**

A To calculate the stock prices used to arrive at dividend yields, Ms. Bulkley uses prices averaged over 30-, 90- and 180-trading-day periods. To reflect current investor expectations, the stock price should be as close to the current spot price as possible. Averaging prices over a short time period to remove the risk of picking an outlier price is appropriate, but the 90- and 180-day periods selected by Ms. Bulkley run the risk of relying on stale information.[31]

My stock prices represent the average of the high and low prices over the 30-day period ending March 21, 2025, with prices obtained from Yahoo! Finance.

***BYRP***

**Q Should the Commission consider the BYRP analysis for estimating ROE?**

A No, it should not. It should be disregarded because it introduces into the calculation of ROE, a process that should be based on objective data as much as possible, the reliance on ROEs set by other regulatory commissions. That regulatory process of setting ROE is, as the research about excessive utility ROEs I discussed above supports, not one that has empirically resulted in returns that would be set by objective financial methodology.

[31] Morin recommends no more than one month for an averaging period. Morin, p. 356: "To guard against the possibility that current stock price reflects abnormal conditions or constitutes a temporary aberration, while at the same time retaining the spirit of market efficiency, averaging stock prices over several recent trading days is a reasonable compromise… The average closing stock price calculated over the most recent 10 trading days period at the time of estimating the cost of equity is a reasonable procedure… A similar average computed over a one-moth period rather than a 10-day period would not be unreasonable."

Ms. Bulkley's risk premium used in her BYRP analysis is the spread between those ROEs historically set by other commissions in rate cases and long-term Treasury bond yields. Therefore, the resulting risk premium she calculates is as large as it is only in relation to the degree that regulatory commissions set ROEs at a premium to what the ROEs would be using only objective financial methods.

This problem with similar Risk Premium models has been cited by FERC as one of the reasons to reject the use of the model. In Opinion No. 569 in a 2019 order, FERC found that "while all models, including the DCF, feature some circularity, such circularity is particularly direct and acute with the Risk Premium model because it directly relies on past Commission ROE decisions."[32] In that decision, FERC also rejected the use of the Risk Premium model because it is "largely redundant with the CAPM."

***Additional Risk Factors***

**Q Please describe how Ms. Bulkley introduces section "VIII. Regulatory and Business Risks."**

**A** Ms. Bulkley states that several additional factors must be considered when determining where the Company's cost of equity falls within the range of analytical results. These risk factors should be considered with respect to their overall effect on the Company's risk profile relative to the proxy group.[33]

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[32] FERC Opinion 569, 169 FERC 61129 (2019), par. 343. Available at: https://www.ferc.gov/sites/default/files/2020-04/E-11_1.pdf.

[33] Bulkley, p. 33, lines 15-19.

**Q What are the additional factors described in "VIII. Regulatory and Business Risks"?**

A The additional factors are flotation costs, capital expenditures, and regulatory risks.[34]

**Q What does Ms. Bulkley find about how Consumers Energy's capital expenditure requirements compare to those of the proxy group companies?**

A Ms. Bulkley finds that Consumers Energy's ratio of capital expenditures as a percentage of net utility plant (61.71%) is lower than the median (66.33%) for the proxy group companies, however the capital expenditures still represent an extensive capital project relative to the total net plant utility.[35] [36]

**Q What does Ms. Bulkley state and suggest about the relationship between capital expenditure requirements and risk?**

A Ms. Bulkley states that substantial capital expenditure requirements adversely affect a company in two significant and related ways: (1) the heightened level of investment increases the risk of under-recovery or delayed recovery of the invested capital; and (2) an inadequate return would put downward pressure on key credit metrics. This suggests that Ms. Bulkley finds that capital expenditure requirements and risk are positively related, with higher capital expenditure requirements associated with higher risk.

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[34] Bulkley, p. 34 line 1, p. 37 line 21, and p. 41 line 11.

[35] Bulkley, p. 38, lines 3-11.

[36] Exhibit A-14 (AEB-1), Schedule D-5, page 27.

**Q Are there any problems with this finding about the Company's risk profile?**

A Yes. This finding is not in keeping with the aim of the section to compare to the proxy companies. Rather, it emphasizes the Company's capital expenditure requirements in a vacuum.

**Q What do you find about how Consumers Energy's capital expenditure requirements compare to those of the proxy group companies?**

A I find that Consumers Energy's ratio of capital expenditures as a percentage of net utility plant is lower than the median for the proxy group companies. Relatedly, I find that the Company's ratio of capital expenditures as a percentage of net utility plant is also lower than the average or mean (67.81%) for the proxy group companies.[37]

**Q What do you find about the overall effect of capital expenditures on the Company's risk profile relative to the proxy group?**

A I find that capital expenditures have the overall effect of lowering the Company's risk relative to the proxy group.

[37] Calculation based on Exhibit A-14 (AEB-1), Schedule D-5, page 27.

**Q What does Ms. Bulkley find about the difference between the Company and the proxy group companies in terms of capital tracking mechanisms?**

A Ms. Bulkley finds that, unlike approximately 71% of companies in the proxy group, Consumers Energy does not recover gas capital investment costs between rate cases utilizing a capital tracking mechanism.[38]

**Q Do you agree with this comparison?**

A No. In Exhibit A-14 (AEB-1), Schedule D-5, page 29, Ms. Bulkley calculates the 71% at the operating subsidiary level for each of the six proxy companies, weighing each operating subsidiary equally. 17 operating subsidiaries have capital tracking mechanisms and 7 do not, with 17/24 rounding to 71%. However, this method weighs the proxy companies with more operating subsidiaries more in the overall calculation than the proxy companies with fewer operating subsidiaries. For example, Atmos and NiSource have 6 and 7 subsidiaries, respectively, so Atmos' weight in the overall calculation is 25% (6/24) and NiSource's is 29% (7/24).[39] Both companies spend a higher percentage on capital expenditures than Consumers Energy does.[40] Ms. Bulkley has neither justified nor described this weighted average method. Absent a justification for weighting proxy companies with more subsidiaries more highly than companies with fewer subsidiaries, Ms. Bulkley should calculate the prevalence of capital tracking mechanisms by weighing each proxy company equally. I calculated the percentage of proxy group companies that

[38] As shown in Exhibit A-14 (AEB-1), Schedule D-5, page 29.

[39] Exhibit A-14 (AEB-1), Schedule D-5, page 29.

[40] Exhibit A-14 (AEB-1), Schedule D-5, page 27.

have mechanisms for some form of capital cost recovery in place by first calculating, for each proxy company, the percentage of operating subsidiaries with tracking mechanisms, and then calculating the average by giving each proxy company an equal weight of 1/6 (17%). I found that 64% of the companies in the proxy group currently have mechanisms for some form of capital cost recovery in place.[41]

**Q What does Ms. Bulkley conclude about the overall effect of capital expenditures on the Company's risk profile relative to the proxy group?**

A Ms. Bulkley states that even though Consumers Energy has lower projected capital expenditure programs relative to net utility plant of the proxy group, the Company still has a significant capital spend program. Further, unlike a number of the operating subsidiaries of the proxy group, the Company does not currently have a capital tracking mechanism for gas capital investment. Ms. Bulkley concludes that this results in greater risk for the Company than the proxy group, all else being equal.[42]

**Q Is this conclusion clear?**

A No. Ms. Bulkley stated that section "VIII. Regulatory and Business Risks" risks including capital expenditures should be considered with respect to their overall effect on the Company's risk profile relative to the proxy group. Ms. Bulkley concludes the capital expenditures section with "This results in greater risk for the

[41] Calculation based on Exhibit A-14 (AEB-1), Schedule D-5, page 29.

[42] Bulkley p. 41, at 5-10.

Company than the proxy group, all else being equal."[43] It is not clear what role this sentence plays in the overall capital expenditures section. One possibility is that this sentence summarizes only the previous sentence ("Further, unlike a number of the operating subsidiaries of the proxy group, Consumers Energy does not currently have a capital tracking mechanism for gas capital investment"). Another possibility is that this sentence summarizes Ms. Bulkley's position on the overall effect of capital expenditures on the Company's risk profile relative to the proxy group (in other words, concluding that the overall effect is that capital expenditures make the Company riskier than the proxy group).

**Q What is the problem if ("This results in greater risk for the Company than the proxy group, all else being equal") only summarizes the previous sentence about the capital tracking mechanism?**

A The problem would be that Ms. Bulkley has not offered a conclusion as to the overall effect of capital expenditures on the Company's risk profile.

**Q What is the problem with the potential conclusion that the overall effect of capital expenditures is to make the Company riskier relative to the proxy group?**

A There are two problems with this conclusion. The first problem is that Ms. Bulkley's first statement ("Even though Consumers Energy has lower projected capital expenditure programs relative to net utility plant of the proxy group over the next five years, the Company still has a significant capital spend program") does

[43] Bulkley p. 41, at 9-10.

not support the conclusion that the Company is riskier relative to the proxy group. Ms. Bulkley compared projected capital expenditures relative to net utility plant and found that the Company's capital expenditure percentage relative to net utility plant is lower than the median of the proxy group, suggesting that the Company has a lower risk profile than the proxy group. Ms. Bulkley claims that "Even though Consumers Energy has lower projected capital expenditure programs relative to net utility plant of the proxy group over the next five years, the Company still has a significant capital spend program." This latter part of the claim may be true but is not essential to the section of testimony, which considers capital expenditures "with respect to their overall effect on the Company's risk profile relative to the proxy group."

The second problem is that, taking the two statements together, Ms. Bulkley has not justified the overall conclusion. Ms. Bulkley makes two contrasting statements about different factors that affect the Company's risk relative to the proxy group but does not indicate or compare their relative importance. It is therefore not clear how these two statements, which have opposite effects, lead to the overall conclusion of "greater risk for the Company than the proxy group." Ms. Bulkley has not justified a conclusion that the absence of a capital tracking mechanism identified in her first statement has a greater impact on the Company's risk profile than the Company's significant capital spend program identified in her second statement, , especially considering my finding that only 64% of the proxy group has a tracking mechanism, not 71%.

**Q Do you have any other concerns about this potential conclusion?**

A Yes. Ms. Bulkley has not justified why it is relevant that the Company has "not requested approval to recover gas capital investment costs between rate cases utilizing a capital tracking mechanism."[44] With capital expenditure requirements lower than both the mean and median of the proxy group, this emphasis on capital recovery tracking is not justified. In Ms. Bulkley's public direct testimony on behalf of Wisconsin Public Service Corporation (WPSC), Ms. Bulkley concluded that "WPSC's capital expenditure requirements as a percentage of net utility plant are significant relative to the proxy group and are expected to continue over the next few years. Furthermore, unlike a majority of the proxy group companies, WPSC does not have capital cost recovery mechanisms to allow for timely recovery of WPSC's capital expenditures between rate cases. Therefore, all else equal, WPSC's capital expenditure plan and limited ability to recover the capital investments as incurred results in a risk profile that is greater than that of the proxy group."[45] While it may make sense to discuss concerns about lack of capital recovery tracking between rate cases for a utility that has "significantly higher"[46] capital expenditure requirements compared to the median of its proxy group, Ms. Bulkley has not justified why the same is necessary for Consumers Energy.

[44] Bulkley p. 40, at 24-25.

[45] Exhibit CUB-20, WPSC Bulkley p. 54 lines 18-21, p. 55 lines 1-3.

[46] Exhibit CUB-20, WPSC Bulkley p. 52, lines 1-2.

**Q Does this conclude your direct testimony?**

**A** Yes, it does.

MS. HILLYER: Next, I move to bind into the record the prefiled direct testimony of Josh W. Denzler, which consists of a cover page, table of contents, and 37 pages of questions and answers, and I will note that there is a public redacted version of Mr. Denzler's testimony and a confidential version submitted under seal.

I will further note that since CUB filed this testimony, the Company has agreed to the removal of the redaction of a number that appeared on page 21, line 6, and page 36, Line 8, and CUB has served the parties with new versions of the public and confidential testimony reflecting the updated redactions, and provided those versions to the court reporter, but has not re-filed its testimony as its contents have not changed.

And at this time, I also would move for the admission of Mr. Denzler's exhibits, consisting of Exhibit CUB-21 through CUB-24, CUB C-25, which is confidential, and CUB-26.

JUDGE VARCHETTI: All right. Well, thank you for making those specifications regarding the testimony.

Are there any objections to the admission of Mr. Denzler's testimony, public and confidential, as revised, or any of the associated

exhibits?

I am hearing none, so the testimony is bound into the record and the associated exhibits are admitted.

MS. HILLYER: Thank you, Your Honor.

(Revised Direct Testimony bound in)

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

| | |
|---|---|
| In the matter of the application of **CONSUMERS ENERGY COMPANY** for authority to increase its rates for the distribution of natural gas and for other relief. | Case No. U-21806 |

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**PUBLIC DIRECT TESTIMONY OF**

**JOSHUA W. DENZLER**

**ON BEHALF OF**

**CITIZENS UTILITY BOARD OF MICHIGAN**

**May 28, 2025**

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## I. INTRODUCTION & QUALIFICATIONS

**Q. Please state for the record your name, position, and business address.**

A. My name is Joshua W. Denzler. I am a Consultant at 5 Lakes Energy, a Michigan limited liability corporation, located at Suite 218, 220 MAC Avenue, East Lansing, Michigan 48823.

**Q. On whose behalf is this testimony being offered?**

A. I am testifying on behalf of the Citizens Utility Board of Michigan (CUB).

**Q. Please summarize your experience in the field of utility regulation.**

A. My work experience is summarized in my resume, provided as Exhibit CUB-21. I have been in the utility industry since the summer of 2014, where I started my career at DTE Energy as a Summer Student (intern) working in continuous improvement for DTE Gas. After completing a second summer internship on the same team in the summer of 2015, I became a student co-op in Gas Construction and Planning.

I began my full-time career in 2017 when I became an Apprentice Planner in Electric Distribution Operations New Business Service Planning. In 2019, I became a Strategist in the Regional Customer Operations division of Electric Distribution Operations. I was promoted to Senior Strategist in this same organization in 2021. As part of my time in Distribution Operations, I worked on several key initiatives including the response to the COVID-19 pandemic, labor relations and union contract negotiations, and was the business unit lead for waste idling reduction. In late 2022, I became a Senior Strategist in Corporate Strategy supporting the Next Generation Utility effort before departing the company in early 2023. From that time until May 2024, I was employed by E Source Companies, LLC,

as a Director of Sales Innovation responsible for marketing advanced data science tools within the utility industry. I have been employed by 5 Lakes Energy since May 2024.

**Q. Please summarize the professional education you've completed relevant to this proceeding.**

A. I have completed the following courses relevant to my testimony and background in this case:

- Electric Utility Pricing – Trends in Cost Recovery | EUCI | July 2024
- Electric Cost-of-Service | EUCI | July 2024
- Annual Regulatory Studies Program: Fundamentals | MSU IPU | August 2024
- Advanced Rate Design for Cost Effective Tariffs | EUCI | December 2024

**Q. Have you testified before this Commission or as an expert in any other proceeding?**

A. I have previously testified before the Michigan Public Service Commission (Commission) in Case U-21534 (DTE Electric Company 2024 Rate Case) and Case U-21585 (Consumers Energy Electric 2024 Rate Case).

**Q. Are you sponsoring any exhibits?**

A. Yes, I am sponsoring the following exhibits:

Exhibit CUB-21: Resume of Joshua W. Denzler
Exhibit CUB-22: Analysis of ARP Collaboration Costs
Exhibit CUB-23: Analysis of ARP LAN Costs
Exhibit CUB-24: Analysis of ARP Other Costs
Exhibit CUB-C25: Analysis of Fleet EV Savings – CONFIDENTIAL
Exhibit CUB-26: Analysis of Costs Due to Waste Idling

## II. SUMMARY

**Q. What major themes does your testimony address?**

**A**. My testimony provides key context on the current state of affordability for Consumers Energy's natural gas customers, juxtaposing that with the uncertainty of the future of gas and the risk for stranded assets from increasing amounts of long-term investment. This paints a pointed backdrop as to the review and understanding of the reasonableness and prudence of the Company's proposed investments. Simply put, customer funds are not unlimited, and with the uncertain future of gas nationally and in Michigan, the Commission must be sure that the Company's proposed spending is necessary and will benefit customers sufficiently in order to consider it reasonable and prudent. After establishing this context, I explain my general methods for calculating reasonable estimates of projected spend based on historical data. I use those methods, in addition to other case-specific reviews, to propose changes or disallowances where the Company has not sufficiently demonstrated the reasonableness and prudence of its projections. I perform this review for certain non-operational categories and projects while tackling other qualitative issues as necessary. Issues related to Gas Operations are discussed by CUB Witness Ram Veerapaneni and certain considerations related to affordability, uncollectibles, and productivity are discussed by CUB Witness Rick Bunch.

**Q. Which Company witnesses' testimony do you discuss in your testimony?**

**A.** I am addressing the testimony of the following Company witnesses:

- Stacy H. Baker
- Corey A. Ballinger
- Jessica R. Byrom

- Quentin A. Guinn
- Austin S. Smith

## III. THE COMPANY'S PLANNED SPENDING, RATES, AND AFFORDABILITY

**Q. What context is important for understanding the reasonableness and prudence of the Company's plans and requests in this case?**

**A**. Both independently and intersected, the uncertainty of the future of gas and mounting concerns around customer affordability provide a critical backdrop for the Company's operations. The recently released report from CUB titled "Investor-Owned Utility Gas Distribution Capital Expenditures: A Study on the Potential Bill Impacts of Business-as-Usual Investment in Michigan" (CUB Report) provides objective, analytical research on this key context.[1] Specific to Consumers Energy, the report's conservative estimate concludes that the average residential customer will see a 158% increase in their monthly bill from 2025 to 2050.[2] While this is concerning enough for customer affordability, that increase is *before* accounting for any decreases in gas consumption that result from electrification, efficiency improvements, or other energy transition factors. Michigan has established aggressive goals to reduce greenhouse gas emissions (from 2005 levels) of 52% by 2030 and net zero by 2050, and natural gas (not including that used for electricity generation) accounts for 23% of Michigan's greenhouse gas emissions.[3] Current levels of

[1] Exhibit CUB-4, sponsored by CUB witness Rick Bunch.

[2] *Id.*, p. 25

[3] https://www.michigan.gov/egle/-/media/Project/Websites/egle/Documents/Offices/OCE/MI-Healthy-Climate-Plan.pdf.

gas consumption are likely to drop as Michigan reduces greenhouse emissions, thereby driving up the rates needed to recover the costs of capital investments.

**Q. How does customer affordability relate to the Company's proposed spending in this case?**

**A**. Underscoring the concerns surfaced by the CUB Report, we also have evidence in this case of the increasing affordability challenges already faced by Consumers' customers. These are testified to in detail by CUB Witness Bunch. In summary, the Company has a demonstrated, growing affordability challenge shown in its increasing numbers of delinquent accounts and uncollectible expense. This affordability challenge is prevalent despite the fact that previous rate increases have been relatively close to, if not less than, inflation. As such, the affordability challenge the Company is facing is very likely to be further exacerbated by its proposed spending and rates, which significantly outpace expected inflation. As also explained by Witness Bunch, the answer is not more assistance, but rather a need for lower rates across the board. Customers cannot afford continuing super-inflationary increases and must receive demonstrable commensurate value for the work the Company is doing in order for that work to be considered reasonable and prudent. Any unnecessary or sub-optimal spending by the Company contributes to a severe affordability concern for its customers.

**Q. In addition to affordability and rate concerns, what other financial concerns exist in the current context of the natural gas industry?**

**A**. One other key risk to understand is that of stranded costs. With the uncertainty around the future of natural gas nationally and within the state of Michigan, decreasing demand for gas will likely not only increase per-unit gas rates but also render certain plant insufficiently useful. As such, investing heavily in this infrastructure could lead to millions, if not billions, of dollars of stranded costs. The continued demand for natural gas is not certain, so neither is the true lifecycle of gas assets. As the Company invests in assets expecting multiple decades of lifespan, both customers and the utility will suffer when those assets are not fully utilized and necessary for the entire duration of that lifespan. This is another reason to carefully scrutinize the Company's proposals to ensure that recovery is authorized for only those costs which are truly necessary and sufficiently demonstrated to be reasonable and prudent. In addition to mounting affordability pressures, the risks of stranded long-term costs paint an important backdrop for review of this case.

## IV. METHODS FOR ASSESSING THE REASONABLENESS OF COMPANY PROJECTIONS

**Q. Please describe your approach to assessing the reasonableness and prudence of the Company's projected expenditures, whether capital or O&M.**

**A**. In my review of the Company's materials, I first qualitatively evaluate the cost, benefit, and overall merits of a given program or project in relation to its reasonableness and prudence. Where I have identified concerns of a qualitative or merit-based nature, I recommend appropriate actions.

In addition to evaluation of the merits of certain spend, I also evaluate the reasonableness and prudence of the analytical methodology employed to arrive at the projected estimate. Where the Company has not sufficiently demonstrated a reasonable and prudent estimation of projected costs, I provide a recommended reasonable estimate in its place.

**Q. What methods do you employ to determine reasonable estimates for projected spend?**

**A**. My analysis will generally take one of two forms, depending on if the projected spend is applicable for a unit-cost approach or needs to be evaluated more case-by-case. When a unit costing method is most appropriate, I evaluate the per-unit costs and unit volumes against historical levels. Where the Company expects significant deviations from historical costs and volumes, I look for sufficient justification for those deviations. When such deviations are not sufficiently justified, I propose more reasonable costs and volumes based on historic data. My costs will use the historical baseline plus a productivity-adjusted inflation (PAI) factor, as explained in detail by CUB Witness Bunch. Witness Bunch's methodology results in the following Total Factor annual PAI factor calculations[4]:

**Table 1: Productivity Adjusted Inflation Factors**

| | 2024 | 2025 | 2026 |
|---|---|---|---|
| Projected Inflation | 3.20% | 2.40% | 2.50% |
| Total Factor Productivity | 0.83% | 0.83% | 0.83% |
| PAI Factor | 2.37% | 1.57% | 1.67% |

When the proposed spending is not fit for a unit-costing approach, I evaluate the specific details of the spend items on a case-by-case basis. Where the analytical justification for these estimates is insufficient, I make recommendations specific to nature of project. In

[4] Refer to the Direct Testimony of CUB Witness Rick Bunch for calculations, and the Direct Testimony of Heather Rayl p. 12 for the Company's projected inflation rates.

several instances, I recommend the Commission treat these projects, at best, as if they are Class III estimates according to the Association for Advancement of Cost Engineering (AACE) classification system. This is a method to mitigate the overfunding of projects based on previous Commission precedent, notably in the Commission's order in Consumers' most recent electric rate case U-21585.[5]

## V. PROPOSED INFORMATION TECHNOLOGY (IT) EXPENDITURES

**Q. What observations do you have for the Company's Gas SCADA Software Solutions Project?**

**A**. The Gas SCADA Software Solutions Project is discussed by Witness Baker and the Company is proposing an increase in total project cost from an estimate of $11.49M in Case No. U-21490 to $18.02M in this case.[6] In discovery, the Company explained the causes for this were higher-than-estimated costs after a request for proposals (RFP) was issued and the Company determining "that additional third-party resources were required to support testing this new technology."[7] The Company did not delineate the costs driven by each factor. The Company also stated that it "found that it lacked sufficient internal resources and skills to support user acceptance and parallel testing."[8]

The Company offers no explanation as to why it could not have anticipated a more reasonable estimate or to why it did not know it could not support user acceptance and parallel testing during the rough order of magnitude (ROM) estimate phase. Additionally,

[5] Refer specifically to the Commission's March 21, 2025, order in Case U-21585, p. 192 where it supports the usage of this methodology as recommended by Staff and adopted in the PFD.

[6] Direct Testimony of Company Witness Stacy H. Baker, pp. 53 and 55.

[7] Consumers response to discovery request U21806-CUB-CE-0121.

[8] Consumers response to discovery request U21806-CUB-CE-0122.

in this same project, the Company originally planned for an initial five-year licensing period, but the project actually requires six years of licensing.[9] In discovery, the Company explained that the six-year licensing period is driven by an implementation period of more than two years and a necessary three-year licensing period afterwards in order to capitalize costs.[10] Again, the Company does not explain why this was not considered at the time the ROM estimate was created.

Another planning deficit from this same project is in the Company's decision to use virtual servers instead of physical servers. When asked why this was not identified in the ROM estimate phase, the Company stated, "it implemented the new operational technology standard to utilize virtual servers afterward."[11] Effectively, the Company answered the question of why a decision was made late with the response that it was because the decision was made late.

Further evidence of the Company's deficiencies in planning this project consist of its projected costs for 2024. When this case was filed in December 2024, the Company projected $8.0M in 2024 costs associated with the SCADA project.[12] However, 2024 preliminary actuals were $3.4M[13] – less than half of the original projection provided at the very end of the year, when the Company should reasonably be expected to have a good handle on the expected costs. In addition, the Company originally did not project any costs

[9] Baker pp. 54-55.

[10] Consumers response to discovery request U21806-CUB-CE-0124.

[11] Consumers response to discovery request U21806-CUB-CE-0124.

[12] Baker p. 54

[13] Attachment U21806-AG-CE-0613_ATT_1 to Consumers response to discovery request U21806-AG-CE-0613.

in 2026 but now has shifted costs from 2025 into 2026.[14] The Company discussed that it extended the Go-Live from late 2025 into early 2026 due to "resource availability in the field construction season."[15] Once again, the Company offered no explanation as to why it did not foresee these constraints when planning the project, as the needs for the field construction season should be reasonably well-known in advance.

In summary, there are myriad changes (and corresponding cost increases) that reasonably should have been known when this project was initially approved. It also worth noting that the Company did not solicit any additional proposals for the $770k in total costs being performed by Black and Veatch[16], so it is unknown whether there exist better alternatives or if the Company received a competitive and reasonable price for this work. The issues in the planning of this project are evidence of a deficient and potentially haphazard estimation and planning process. The presence of these deficiencies in this project implies similar deficits in the IT project planning process across the Company.

**Q. Are there other concerns with the Gas SCADA Project besides the deficiencies in the planning process?**

**A**. Yes, in addition to the gaps in the planning process, the merits and necessity of the project are not sufficiently justified as reasonable and prudent. This is true for both the original project scope and the incremental costs being requested in this case. For the original overall project, while the Company provides an explanation of concerns with the current system, these seem to be based primarily on hypothetical future risk. This is evidenced in Witness

[14] Attachment U21806-AG-CE-0613_ATT_1 to Consumers response to discovery request U21806-AG-CE-0613.

[15] Consumers response to discovery request U21806-AG-CE-0613, part g.

[16] Consumers response to discovery request U21806-AG-CE-0613, parts e and f.

Baker's testimony when she states, "The current legacy system is operating at well beyond its original design specification, so the potential points of failure are not fully known or understood."[17] However, there is limited evidence to suggest that the current system is defective and need of imminent replacement, especially at such a substantial cost. The current system has only experienced 11 significant incidents in the last three years, four of which were due to cellular provider outages and one of which was due to "human error" - and it is not well explained if the remaining six incidents would have been avoided under a new SCADA system.[18] Additionally, there exist no current concerns about the ending of product support, as the current vendor has not yet notified the Company of any end to current product support on its end.[19] When looking at the incremental costs being requested for recovery, the Company provides limited and insufficient explanation as to the necessity of these costs. For the new contractor support costs, the Company simply states it lacks the resources and expertise to perform these functions.[20] There is insufficient explanation of what expertise it requires and why that is worth the cost it is paying. A similar deficiency exists related to its use of virtual servers. The Company states these servers are more efficient and functional to operate, but more expensive up front.[21] However, there is not sufficient analysis and evidence to evaluate the cost/benefit of this tradeoff, rendering the Company's request insufficiently supported to demonstrate reasonableness and prudence.

[17] Baker p. 51.

[18] Consumers response to discovery request U21806-AG-CE-0847.

[19] Consumers response to discovery request U21806-AG-CE-0612.

[20] Consumers response to discovery request U21806-CUB-CE-0123.

[21] Consumers response to discovery request U21806-CUB-CE-0123.

**Q. What conclusions and recommendations do you draw that relate to the Gas SCADA Project?**

**A**. As discussed above, this project is a major investment in Gas IT and exhibits defects both in its planning and overall merit. As such, it is reasonable and prudent for the Company to recover the additional costs related to this project, and recommend the Commission disallow such increases and hold the total allowed capital at $11,491,200 as previously approved in U-21490. This represents a total capital disallowance of $6,524,840.

**Q. What values are reflected in this case as it relates to the Company's Rough Order of Magnitude (ROM) estimates?**

**A**. As noted by Witness Baker, the Company has taken its ROM estimates and reduced them by a factor of 20% in response to previous Staff recommendations and Commission decisions, particularly referencing Case No. U-20963.[22] That is, for every $1.00 of ROM-estimated capital spending, the Company is requesting recovery of $0.80 of the original estimate.

**Q. What concerns do you have regarding this methodology?**

**A**. First, if the Company knows that a 20% reduction on its ROM estimates will be applied, there is little protection against inflation of those estimates by 20% in anticipation of that reduction. A much larger concern I have is that the Company has routinely underspent its ROM estimates by a much larger margin than 20%. As summarized in Table 2[23] below, I compared the Company's data on its ROM projections from three different cases to the

[22] Baker p. 46.

[23] Source: Consumers response to discovery request U21806-CUB-CE-0119.

actual spend from those projects. With one limited exception in 2022 Annual Projects, the Company's actual costs for projects tend to come in well over 20% under the ROM estimate.

**Table 2: ROM Estimate Analysis**

| U21148 | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|
| | ROM Estimate | | | Actuals* | | | Actual Variance to Estimate | | |
| Project Category | Projected Capital | Projected O&M | Total | Capital | O&M | Total | Capital | O&M | Total |
| 2022 Annual Projects | 5,417,132 | 2,220,392 | 7,637,524 | 4,242,244 | 2,678,079 | 6,920,323 | -22% | 21% | -9% |
| 2023 Annual Projects | 4,999,053 | 2,555,226 | 7,554,279 | 1,190,678 | 873,855 | 2,064,533 | -76% | -66% | -73% |
| 2024 Annual Projects | *NA* | *NA* | *NA* | *NA* | *NA* | *NA* | *NA* | *NA* | *NA* |
| Projects | 27,465,490 | 6,348,793 | 33,814,282 | 15,947,767 | 4,030,212 | 19,977,979 | -42% | -37% | -41% |
| Total All Categories | 37,881,675 | 11,124,411 | 49,006,086 | 21,380,688 | 7,582,146 | 28,962,835 | -44% | -32% | -41% |

| U21308 | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|
| | ROM Estimate | | | Actuals* | | | Actual Variance to Estimate | | |
| Project Category | Projected Capital | Projected O&M | Total | Capital | O&M | Total | Capital | O&M | Total |
| 2022 Annual Projects | *NA* | *NA* | *NA* | *NA* | *NA* | *NA* | *NA* | *NA* | *NA* |
| 2023 Annual Projects | 2,349,999 | 3,218,108 | 5,568,107 | 125,493 | 236,395 | 361,888 | -95% | -93% | -94% |
| 2024 Annual Projects | 1,195,167 | 3,031,139 | 4,226,306 | 811,450 | 1,152,158 | 1,963,608 | -32% | -62% | -54% |
| Projects | 10,868,735 | 3,518,966 | 14,387,701 | 4,662,609 | 592,695 | 5,255,304 | -57% | -83% | -63% |
| Total All Categories | 14,413,901 | 9,768,213 | 24,182,114 | 5,599,552 | 1,981,248 | 7,580,800 | -61% | -80% | -69% |

| U21490 | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|
| | ROM Estimate | | | Actuals* | | | Actual Variance to Estimate | | |
| Project Category | Projected Capital | Projected O&M | Total | Capital | O&M | Total | Capital | O&M | Total |
| 2022 Annual Projects | *NA* | *NA* | *NA* | *NA* | *NA* | *NA* | *NA* | *NA* | *NA* |
| 2023 Annual Projects | *NA* | *NA* | *NA* | *NA* | *NA* | *NA* | *NA* | *NA* | *NA* |
| 2024 Annual Projects | 1,205,479 | 4,271,683 | 5,477,162 | 811,450 | 1,152,158 | 1,963,608 | -33% | -73% | -64% |
| Projects | 3,469,520 | 721,148 | 4,190,668 | 2,599,802 | 530,560 | 3,130,362 | -25% | -26% | -25% |
| Total All Categories | 4,674,999 | 4,992,831 | 9,667,830 | 3,411,252 | 1,682,718 | 5,093,969 | -27% | -66% | -47% |

**Q. What recommendations do you have regarding the ROM projections?**

**A**. In light of the Company's significant over-estimation of ROM projections, I recommend the Commission disallow a total of 40% ROM projections for 2025 and 2026 – this is an incremental 20% over the Company's 20% reduction. As demonstrated in Figure 1 above, a total of 40% is reasonable given the historic levels of ROM underspend. This level results in an incremental disallowance of $8.21M (20% of $41.04M) in 2025 capital spend, and an incremental disallowance of $11.59M (20% of $57.46M) in 2026.

**Q. Please explain your findings as they relate to the Company's projected spend for the Asset Refresh Program (ARP) – Collaboration.**

**A**. Company Exhibit A-22 (SHB-7) Page 1 of 12 depicts the unit volumes and costs for actual purchases in 2023-2024 and projected purchases for 2025-2026. As I reviewed the Company's data here, I found that the projections for many devices were far in excess of historic costs for the same devices, even accounting for productivity-adjusted-inflation. No explanation was offered for how the unit costs were determined and why such significant increases were expected. As no justification exists for increases in cost so dramatically above inflation, I am recommending that the historical unit costs be adjusted by the PAI factor previously discussed for the applicable items. This represents a disallowance of $57,599 in 2025 and $88,718 in 2026. The details of this analysis can be found in CUB-22, Analysis of ARP Collaboration Costs.

Of particular note, the Company's over-estimation of Collaboration device costs appears contradictory to its own approach to projecting device costs in other IT areas of the same exhibit. Looking at Page 4 of 12, the Company projects costs for Field Device purchases, and the estimated unit costs for 2025 and 2026 device purchases are identical to the 2024 unit costs for those devices. Under this version of the Company's methodology, my productivity-adjusted-inflation modifier is actually an overestimation – albeit a much less dramatic one than the Company's original projection.

**Q. Did you find any other similar estimation issues with any other ARP categories?**

**A**. Yes, a very similar situation exists within the Local Area Network (LAN) category. In 2023 and 2024, the Company replaced 1091 LAN Switches for a total cost of $2,793,094 – a unit cost of $2,560 per switch. However, the Company projected a unit cost of over $5,000

for 2025 and 2026 switches. Once again, no sufficient explanation has been offered for this marked increase, and I recommend the Commission use historic unit costs, adjusted for PAI, in determining the projected unit costs for 2025-2026. As detailed in CUB-23, Analysis of ARP LAN Costs, this amounts to a disallowance of $55,911 in 2025 and $86,881 in 2026.

**Q. What are your recommendations overall for the Asset Refresh Program in light of these findings?**

**A**. As noted above, the Company overestimated their costs for Collaboration Devices and LAN Switches for which they had a solid historic cost basis for developing cost projections. This creates concern over their methods for estimating the costs of other devices for which there is not a similar historical basis. Consistent with my recommendations for other areas that have insufficient justification for their cost estimation, I recommend the Commission treat these similar to Class III AACE estimates and disallow 20% of the remaining ARP spend, a total of $1.41M in 2025 and $1.58M in 2026, as shown in Table 3:[24]

**Table 3: ARP Overall Disallowance Calculations**

| | Total 2025 Dollars | 2025 Gas Share | Total 2026 Dollars | 2026 Gas Share |
|---|---|---|---|---|
| CORE Network Upgrade | $ - | $ - | $ 539,800 | $ 169,659 |
| Cyber Security | $ 450,500 | $ 141,592 | $ 453,500 | $ 142,535 |
| Field Device Asset Mgmt | $ 3,457,044 | $ 1,086,549 | $ 7,678,471 | $ 2,413,343 |
| Infoblox | $ 978,213 | $ 307,452 | $ 197,440 | $ 62,055 |
| OT Support Gas | $ 979,178 | $ 307,756 | $ 2,765,844 | $ 869,305 |
| Physical Security | $ 1,902,740 | $ 598,031 | $ 2,473,362 | $ 777,378 |
| Printer Asset Management | $ 1,611,861 | $ 506,608 | $ 130,839 | $ 41,123 |
| Radio | $ 2,388,927 | $ 750,840 | $ 2,508,316 | $ 788,364 |
| Server and Storage | $ 1,739,577 | $ 546,749 | $ 2,302,530 | $ 723,685 |
| Workstation Asset Management | $ 8,982,469 | $ 2,823,190 | $ 6,070,278 | $ 1,907,888 |
| Total Projected Cost | $ 22,490,509 | $ 7,068,767 | $ 25,120,380 | $ 7,895,335 |
| 20% Disallowance Amount | | **$1,413,753** | | **$1,579,067** |

[24] CUB-24, Analysis of ARP-Other.

**Q. What are your findings regarding the Company's Asset Accounting Tax Upgrade Project?**

**A**. The Company's proposal here is to upgrade their current on-premises software with the SaaS version of the same software due to ending vendor support. Of note here is that the Company did not evaluate other software options and does not even understand the capabilities of other technologies with certainty stating that they "may not provide regulatory reporting and other needed improvements."[25] With vendor support ending in 2025, the Company has left themselves little time to do a proper cost-benefit evaluation of their options. In light of this poor planning, I recommend that the Commission disallow the requested $126,165 in O&M for this project in the test year, requiring the Company to provide suitable evaluation of alternatives as a prerequisite to being granted recovery in a future case. If the Commission does not see fit to disallow the entire project, I would recommend the Commission treat this like a AACE Class III estimate and order a 20% disallowance of $25,233.

**Q. What are your findings for the Company's requested spend on IT Enhancements?**

**A**. The Company defines Enhancements as "smaller, short-cycle technology efforts to implement new or improved functionality and provide the flexibility needed to respond to rapidly changing business and customer conditions."[26] The Company states that these requests must be accompanied by cost and benefit information and are reviewed by a cross-functional team but does not provide any details on the approval criteria.[27] In Exhibit A-

[25] Baker p. 76.

[26] Baker p. 92.

[27] Baker p. 93.

25 (SHB-10), the Company provides the Enhancements worklist for 2016 through October 2024. In this list, there is no evidence of prioritization of activities. In addition, while the Company describes these projects as "smaller" – there are 57 line items with a cost of at least $100,000 and one line item with a cost as much as $2.1M.

These insights beget two concerns. The first is that the Company has not sufficiently demonstrated the reasonableness and prudence of the items on this list. There is no information supporting the necessity or benefit of these projects. The second is the inclusion of many larger-cost projects, which should not be included in Enhancements and instead be standalone projects with project plans and appropriate governance. As such, it would not be reasonable and prudent to allow the Company its requested 53% increase in Enhancements ($7.4M in the test year compared to three-year average of $4.8M). Instead, a more reasonable allowance would be for the three-year average with an adjustment for the PAI factor. This allows the Company to increase the funding it has for its smaller projects but recognizes that ratepayer funding is not infinite. This approach would encourage prioritization of the most valuable projects and balance improvement with a reasonable level of affordability. The Company's three-year average for 2022-2024 was $4,848,979.[28] As discussed earlier in my testimony, the PAI factor for 2025 is 1.57% and for 2026 is 1.67%. This would bring Enhancements spending to $4,925,108 in 2025 and $5,007,357 for 2026. This represents a recommended disallowance of $2,651,057 in 2025 and $2,062,093 in 2026 compared to the Company's original projections.

[28] Baker p. 95.

## VI. PROPOSED FLEET EXPENDITURES

**Q. What is the Company's blended factor as it pertains to Fleet replacements?**

A. The Company's blended factor, as described by Witness Ballinger, "takes age, usage, and mileage into consideration and establishes a replacement priority for units that are more economical to replace than continuing to maintain" and "a Blended Factor result greater than 0.00% indicates that a vehicle is at or past its expected life and is therefore eligible for consideration for replacement."[29] Though a Blended Factor higher than zero does not automatically determine replacement, it is the primary filter for determining replacement eligibility.[30]

**Q. How has the Company evaluated the effectiveness or accuracy of the Blended Factor in identifying candidates for replacement?**

A. In response to discovery, the Company indicated it "has not, however, completed a full analysis of units that have failed prior to replacement as determined by the Blended Factor." It also indicated it "has experienced instances of major component failure in units with a Blended Factor rating of 0.0% has experienced major failures in assets with a Blended Factor of rating of 0.00%."[31] Essentially, the Company has stated that it has not evaluated the accuracy of its Blended Factor tool and has known examples where that tool has failed to predict failures in its Fleet assets.

[29] Direct Testimony of Company Witness Corey E. Ballinger, p. 10.

[30] *Id.*

[31] Consumers response to discovery request U21806-CUB-CE-0225.

**Q. What does this lack of evaluation of the Blended Factor mean for this case?**

A. As the Company has not provided sufficient demonstration of the reliability and accuracy of the Blended Factor in determining replacement candidates, and the Blended Factor is the main filter for determining such candidates, the Company has not sufficiently demonstrated the reasonableness and prudence of its replacement plans. These plans should be considered preliminary, at best, when considered by the Commission for recovery.

**Q. What is your recommendation as it relates to the issues with the Company's Blended Factor?**

A. As the Company's fleet replacement estimates are not sufficiently justified and should be viewed as preliminary, I recommend the Commission disallow 20% of the Company's proposed Fleet Vehicle Capital Replacement spend in the bridge period and projected test year. Per Exhibit A-12 (CEB-1), this would be a disallowance of $3.39M for the 22 Mos Ending 10/31/25 (bridge period), and $2.58M for the 12 Mos Ending 10/31/2026 (test year).

**Q. What are the Company's plans in this case for electrifying its fleet?**

A. In its initial filings, the Company stated it currently operates 284 electric vehicles[32] (EVs), which was updated to 302 EVs in response to discovery.[33] The Company's definition of EV includes plug-in hybrid vehicles, forklifts, and diesel trucks with secondary electric fuel. It also plans to purchase nine electric pickup trucks in the projected test year[34] and

[32] Ballinger p. 26.

[33] Consumers response to discovery request U21806-AG-CE-0642.

[34] Ballinger p. 36.

discusses the benefits of these EVs, including savings on fuel and maintenance.[35] However, in discovery, the Company stated, "it has not yet incorporated specific fuel, maintenance and other savings assumptions into its budget projections for the replacement of an ICE vehicle with an EV."[36] Given the improvements to cost of ownership and reduction in tailpipe emissions, it is incredibly important that the Company continue to electrify its fleet and model this transition for its customers. However, it is also critical that the Company account for savings in its budgeting and accurately recover costs. As it stands, the Company acknowledges unaccounted-for EV savings on fuel and maintenance and thus will over-recover maintenance and fuel costs for these vehicles without an appropriate offset.

**Q. What would an appropriate estimate be for the operating savings of the Company's electrified fleet?**

A. As part of the PowerMIFleet initiative in its electric business, the Company conducted an analysis of the costs of ownership between an EV and an internal combustion engine (ICE) in Fleet applications. The Company only provided information on limited categories of vehicle, so I relied primarily on its estimated savings for vans and light-duty pickup trucks. The light-duty pickup estimates were used for both Company pickups and sedans, as the Company only estimated police-sedan-specific savings which are significantly higher and are not applicable to the Company's sedan usage. See CONF Table 4 below for the estimated savings across the major categories of passenger EVs owned by the Company:[37]

[35] Ballinger p. 37.

[36] Consumers response to discovery request U21806-CUB-CE-0229.

[37] Ex. CUB-C25, Analysis of Fleet EV Savings

**CONF Table 4: Electric Fleet Savings**

| Fleet Asset | Number in Service[38] | Unit Fuel & Maint. Savings | Total Savings for All Units |
|---|---|---|---|
| [redacted] | [redacted] | [redacted] | [redacted] |
| [redacted] | [redacted] | [redacted] | [redacted] |
| [redacted] | [redacted] | [redacted] | [redacted] |

**Q. What is your recommendation as it relates to the cost savings from electrifying fleet vehicles?**

A. Given the Company's own annual savings estimates for electrified fleet vehicles as detailed in Table 4, I recommend a total disallowance to Fleet O&M responsibility costs of $72,720 – this includes existing assets and the nine test year electric pickup purchases. I also recommend that the Commission order the Company to conduct a more specific study as to the expected savings of electrifying its fleet assets, by asset type (light duty car, pickup, van, heavy-duty, etc.) to be provided in the next rate case and the results incorporated into future requested cost recovery.

**Q. Please describe the Company's projected Fleet Responsibility costs.**

A. The direct testimony of Company Witness Ballinger describes that the Company does not have specific Fleet O&M expenses, but that Fleet-related O&M (and capital) expenses come in the form of "Fleet Responsibility" costs. [39] These costs are presented historically in Exhibit A-27. From Witness Ballinger's testimony and exhibits it appears that the only

[38] Source: Confidential attachment U21806-AG-CE-0642_Quentin_ATT_9. CONFIDENTIAL to Consumers response to discovery request U21806-AG-CE-0642.

[39] Ballinger p. 6.

Fleet O&M costs incurred by the Company come by way of these Responsibility costs. The Company is projecting $75M in total Responsibility costs in 2025 and "similar total costs" in 2026[40]. The Company is not able to provide the breakdown in Responsibility costs between capital and O&M and overall provided little detail regarding these costs. When asked to provide a breakdown of the allocation of capital and O&M, the Company was unable to do so, stating: "Given the number of internal orders, clearing accounts, and cost centers through which fleet responsibility costs settle to O&M and/or Capital, it would be very cumbersome to attempt to determine with reasonable accuracy the allocation of fleet responsibility costs for each category outlined in Exhibit A-27." [41] The Company is also unable to delineate the projected responsibility costs for the test year, stating: "Projected fleet responsibility costs would be included as part of the projections of other Company witnesses as applicable, and the Company has not analyzed any variance between projected test year costs and 2024 actual fleet responsibility costs." [42]

**Q. What are your concerns regarding the Company's projected fleet responsibility costs?**

A. The Company has provided insufficient information to evaluate these costs. There is inadequate ability to trace the impact to O&M versus capital, or to understand specifically what value the fleet responsibility work is adding and how that tracks for projected years

[40] Consumers response to discovery request U21806-CUB-CE-0698.

[41] Consumers response to discovery request U21806-CUB-CE-0223a.

[42] Consumers response to discovery request U21806-CUB-CE-0223b.

to historical. As such, the Company has not demonstrated the reasonableness and prudence of these costs.

**Q. What are your recommendations regarding the fleet responsibility costs?**

A. Given that the Company has not established the reasonableness and prudence of these costs, the technically-correct ratemaking outcome would be to disallow all of the fleet responsibility costs. However, recognizing the impact that course of action would have on fleet operations, I instead recommend a 20% disallowance to recovery of Fleet Responsibility costs and that the Commission order the Company to provide more detail on fleet responsibility costs in future cases. Given the Company has only provided 2025 projections, stating that 2026 would be similar, I am recommending a disallowance 20% of $74.04M, or $15.008M in both 2025 and 2026 (for a total of $30.016M in both years). For future rate cases, I recommend that the Commission's order specifically directs the Company to provide historical and projected fleet responsibility costs by capital and O&M, with more detailed information on the types of work these dollars support and the value received for these expenditures, by cost category and business unit.

**Q. Why is vehicle idling an issue for commercial fleets, particularly those in the utility industry?**

A. As stated by the Department of Energy Office of Energy Efficiency and Renewable Energy, "The low-hanging fruit of fuel economy, idle reduction is a simple way to use less fuel and minimize engine wear, reducing costs along with pollution and greenhouse gas

emissions.[43]" Given the large size of the fleets used by utilities, both in terms of number of vehicles and the propensity of large assets such as bucket trucks, the impacts of wear, fuel reduction, and emissions can be significant.

**Q. What information did the Company provide regarding its vehicle idling?**

A. The Company is exclusively addressing the reduction of idling through idling mitigation technologies, which are discussed in the direct testimony of Corey Ballinger. The Company is not employing any behaviorally targeted actions to encourage employees to idle less, stating it "does not characterize any fleet idling as unnecessary.[44]"

**Q. Does the Company's view on idling comport with industry best practice?**

A. No, at least not fully. While idling mitigation technologies are an important step to reduce vehicle idling, the concept that no fleet idling is unnecessary is illogical. Here it is important to delineate between the concept of necessary idling and waste idling. Examples of necessary idling are idling to keep a safe temperature in a vehicle or idling to run the power-take-off (PTO) to power work equipment. Waste idling is often for convenience or a result of habitual forgetting to turn off the vehicle. It is also idling for cabin climate control for longer than necessary (e.g., letting a truck warm up for an hour when it only needs fifteen minutes). It is incredibly unlikely that no unnecessary idling occurs at the Company. When the Company states it does not characterize "any" idling as unnecessary, it effectively declares that not a single employee allowed a single vehicle to idle for a single second longer absolutely necessary. While it can be difficult and complex to delineate

[43] https://cleancities.energy.gov/technical-assistance/idlebox/

[44] Consumers response to discovery request U21806-CUB-CE-0228.

between necessary and waste idling, it is not reasonable or prudent to assume that no unnecessary idling is occurring. In addition, when such unnecessary idling is behaviorally driven (e.g., an employee warming up their truck for longer than necessary), this can be addressed without the additional cost of investing in idling mitigation technologies.

**Q. Can you provide an example of the scope of the Company's current costs of idling?**

A. Yes. Based on fleet data from the Company[45], fuel waste from the Argonne National Labs IdleBox initiative[46], and fuel prices from AAA[47], I was able to approximate wasted fuel costs from idling in the largest categories of fleet vehicles. See Table 5 below for the results of this analysis.[48] It is important to note a few things in these figures. First, this is idling excluding PTO hours – meaning that this does not include idling that was used to power jobsite truck equipment. As such, this is already factoring out a large portion of necessary idling, making this figure closer to the actual waste idling hours. Second, this is only calculated for a subset of vehicle categories due to the available data on fuel waste – meaning this is likely an underestimation of the total fleet fuel waste. And third, this is only cost of fuel waste and does not take into account the costs of additional wear-and-tear or emissions which would further increase the total cost from idling. The Company also did not provide the time horizon for when this idling occurred, so we do not know if this idling occurred over a month, a year, or the life of each vehicle. With that context, here is an estimate of just a portion of the costs, for a portion of the idling, the Company experienced:

[45] Attachment U21806-CUB-CE-0699_Guinn_ATT_1 to Consumers response to discovery request U21806-CUB-CE-0699.

[46] https://www.anl.gov/sites/www/files/2018-02/idling_worksheet.xls - as no value was available specifically for pickup trucks or vans, the sedan – Crown Victoria figure was used as an approximation.

[47] https://gasprices.aaa.com/?state=MI (taken 4/9/25).

[48] CUB-26, Analysis of Costs Due to Waste Idling.

**Table 5: Idling**

| Vehicle Type | Total Idling Hours (excl. PTO) | Idling Fuel Burned (Gal/Hr) | Total Fuel Burned from Idling (Gal) | Fuel Type | Fuel Cost per Gallon | Total Cost of Idled Fuel |
|---|---|---|---|---|---|---|
| Regular Bucket | 92,323 | 0.90 | 83,091 | Diesel | $3.536 | $ 293,809 |
| Digger Derrick | 55,859 | 0.90 | 50,273 | Diesel | $3.536 | $ 177,766 |
| Pickup Truck | 737,709 | 0.39 | 287,706 | Gas | $3.166 | $ 910,879 |
| Service Bucket | 54,159 | 0.90 | 48,743 | Diesel | $3.536 | $ 172,356 |
| Van | 419,902 | 0.39 | 163,762 | Gas | $3.166 | $ 518,470 |
| Total | 1,359,953 | NA | 633,576 | NA | **Total** | **$ 2,073,281** |

**Q. What are your recommendations as it relates to fleet idling in this case?**

A. As demonstrated above, when looking at a conservative estimate of only a portion of idling costs, the Company burned over an estimated 1.3M gallons of fuel at a cost exceeding $2M. Recognizing this is an approximation, more information is needed to ensure the Company is addressing this source of waste and pollution. As such, I recommend the Commission order the Company to prepare a more detailed analysis of its vehicle idling containing the following elements:

- An assessment, based on research and best practice, of waste versus necessary idling by vehicle type;
- An estimate of the fuel costs for waste and necessary idling by vehicle type based on the Company's annual average cost of fuel;
- An estimate of the wear-and-tear from waste and necessary idling, in terms of equivalent miles driven, based on research and best practice, by vehicle type; and

- An estimate of the tons of carbon dioxide released during waste and necessary idling, by vehicle type, based on research and best practice.

## VII. PROPOSED CUSTOMER SERVICE EXPENDITURES

**Q. Please describe the Company's plans for the Customer Order Service Tracker (COST) project.**

A. As detailed in the direct testimony of Jessica Byrom, the COST project will implement a tracker for external and internal visibility into service orders across the Company's service areas. Byrom states that it will add value through increased customer transparency, a reduction in contact center call volume, and decreasing wasted truck rolls.[49] The Company is expecting a 12%-15% reduction in truck rolls with an estimated cost per truck roll of $450.[50] The Company experienced an annual average of 62,954 gas service orders from 2021 to 2024.[51] It also expects a 10-20% customer adoption of the COST tool, which would create a corresponding but not-provided reduction in work-order-related calls at a cost per call of $10.18.[52] In the business case for the COST project, the Company notes approximately 346,000 short-cycle-related contact center calls.[53]

[49] Direct Testimony of Company Witness Jessica R. Byrom 10-11.

[50] Consumers response to discovery request U21806-CUB-CE-0702.

[51] Calculated from Consumers response to discovery request U21806-CUB-CE-0232.

[52] Consumers response to discovery request U21806-CUB-CE-0703.

[53] Exhibit A-21 (SHB-6) p. 45.

**Q. Has the Company incorporated the anticipated savings from the COST into its budget projections?**

A. No, it has not. While the Company has quantified the expected savings at a per-unit level, it has not incorporated them into its cost projections stating, "These costs savings are estimated and are therefore not included in the Company's future cost projections."[54] However, in the usage of a projected test year, all of the Company's costs are estimated. If the Company truly feels that the use of estimates is not reliable for its cost projections, I would welcome a return to purely historical test year ratemaking. However, given that the Company has elected to use projected a test year in this case, it is not fair to its customers for it to pick and choose which estimates get passed through to their revenue requirement. As it stands, the Company's customers will pay for this project and the Company will retain all of the benefits, over-recovering from its customers for the avoided truck rolls and contact center calls.

**Q. What is your recommendation as it relates to the COST project benefits?**

A. From the Company's logic, there are 346,000 short-cycle-related calls with an expected adoption rate of 10%-20%, resulting in an expected avoidance of 34,600-69,200 calls. At $10.18 per call, this would be an annual savings of $352,228 to $704,456. I recommend a disallowance to Customer Service Contact Center O&M of the midpoint of this range which is $528,342. For the savings related to truck rolls, the Company should reduce 12%-15% of the 62,954 service-order-related annual truck rolls. At a cost of $450 per roll, that

[54] Consumers response to discovery request U21806-CUB-CE-0703.

results in a savings of $3,399,516 to $4,249,395. I recommend a disallowance to Gas Operations O&M of the midpoint of these numbers, which is $3,824,456.

## VIII. PROPOSED FACILITIES EXPENDITURES

**Q. Please describe the Company's proposals regarding the Lansing Service Center in this case.**

A. Due to the assessed condition of the existing Lansing Service Center and concerns with its current location, the Company has decided to pursue construction of a new service center at a new location to replace the existing one. The Company is requesting $14.937M in the 22-month bridge period and $7.199M in the test year to be recovered in this case for this project.

**Q. Please describe the Company's proposals regarding the Lansing Service Center in this case.**

A. This project has seen multiple changes since its inception, including a three-year delay in expected completion (originally 2023, now 2026) and changes in project scope resulting in a decrease in project costs. In its order in case U-21585, the Commission noted concern with the Company's "lack of progress"[55] and found the Company had not spent all of its previously allocated funds for this project. Accordingly, it disallowed all projected costs for this project in U-21585. Given the recency of the order in U-21585, these concerns are still very much relevant. While U-21585 was an electric case, as a common asset, the Company's deficiencies in this project remain material for this case as well.

[55] Case No. U-21585, Order, March 21, 2025, p. 173.

**Q. What are your recommendations for the Lansing Service Center project?**

A. Given the lack of progress in this project, I recommend the Commission maintain consistency with its order in U-21585 and disallow $14.937M in the 22-month bridge period and $7.199M in the test year for this project.

**Q. Please describe the Company's proposals regarding the Hastings Service Center in this case.**

A. As noted in the direct testimony of Quentin Guinn, the Company plans to construct a new Hastings Service Center at the existing service center location and is requesting $114,000 (gas allocation) in the 22-month bridge period in support of this project.

**Q. How has the Company's progress been regarding the Hastings Service Center project?**

A. A similar story exists in the Hastings Service Center project as it does in the Lansing Service Center project. In the Commission's order in case U-21585, it found that the project has been moving at a "slow pace"[56] since originally approved, underspending allocated funds and experiencing uncertainty in its future cost projections as a result. The Commission's previous opinion that "it is not reasonable or prudent to approve additional capital investments for this project at this time"[57] still remains applicable. This is underscored by more recent developments in which the Company was supposed to close

[56] *Id.*, p. 176.

[57] *Id.*

on the purchase of a parcel of land from the Barry County Road Commission in Q4 2024, which experienced yet another delay into Q1 2025.[58]

**Q. What are your recommendations for the Hastings Service Center project?**

A. Similar to my recommendation for the Lansing Service Center, I recommend the Commission disallow the Company's requested $114,000 in the 22-month bridge period for the Hastings Service Center project in this case.

**Q. Please describe the Company's proposal as it relates to the Kalamazoo Service Center?**

A. The Company is proposing to renovate the existing Kalamazoo Service Center at a total cost of $35M, which includes environmental, structural, mechanical, and functional upgrades. The gas allocations of cost in this case are $10.949M in the 22-month bridge period and $3.080M in the test year.[59]

**Q. What observations do you have related to the Company's plans?**

A. The Company states that the renovation design will "incorporate and allow for up to 40% future growth opportunities."[60] This is an indication that the facility is being overbuilt by a factor of 40% to current needs. The Company has not provided sufficient evidence that it is expecting a 40% growth in its Kalamazoo Service Center employee population.

[58] Consumers response to discovery request U21806-CUB-CE-0266.

[59] Guinn pp. 30-32.

[60] Attachment U21806-AG-CE-0654-Guinn-2 to Consumers response to discovery request U21806-AG-CE-0654.

**Q. What recommendations do you have for the Kalamazoo Service Center Renovation project?**

A. Given the inherent overbuild in the Service Center, by the Company's own estimation, is 40%, I recommend a disallowance of 40% of the requested costs in this case to encourage the comment to right-size its renovation efforts. This represents a disallowance of $4.38M in the 22-month bridge period and $616k in the test year.

## IX. PROPOSED CHANGES TO RATE DESIGN

**Q. What is the Company proposing in this case as it relates to the monthly fixed customer charge?**

A. The Company is proposing to increase the residential customer charge from $15 per month per customer to $20 per month per customer.[61]

**Q. Do you agree with the Company's proposal to increase this charge?**

A. No, I do not. There are four main reasons why I oppose this change:

1. Higher customer charges are more regressive, which harms low-to-moderate income (LMI) and other vulnerable customer populations
2. High customer charges further impede customer interests through poor price signals
3. Customers do not prefer high customer charges
4. Consumers' current fixed charge is already high compared to other Michigan gas utilities

[61] Direct Testimony of Company Witness Austin S. Smith, p. 8.

**Q. How do higher customer charges impact LMI and otherwise economically vulnerable customer populations?**

A. Fixed charges create regressive rate structures that can be very damaging to low-income or other vulnerable households. While the Company points out that increasing the fixed charge would increase the RIA credit, creating more relief on those customers' bills[62], this ignores two key facts. First, that the Company could increase the RIA credit without increasing the fixed charge. And second, that the Company is not able to reach all LMI customers with its assistance programs, which include the RIA. As noted in Witness Bunch's testimony, Company Witness Jessica Byrom notes that "only one in six LMI (Low and Moderate Income) customers engage in Consumers Energy Assistance programs with the majority of these interactions driven by immediate crises that limit ability to introduce solutions and programs given the urgent customer need."[63] As such, this increased fixed charge is far more likely to harm low-income customers, especially those with proportionally lower usage, than it is to provide them any relief.

**Q. How do higher customer charges impact customer interests through price signals?**

A. As these fixed charges increase, the volumetric rates for natural gas subsequently decrease, which reduces the price signals that encourage customer energy waste reduction. As customer usage becomes decoupled from their bill, the ability to conserve energy and save money is impeded. This limits the customer's ability to reduce their bills by adjusted

[62] Smith p. 8.

[63] Byrom p. 19.

consumption, creating economic harm and reducing customers' overall power of choice over their energy burden.[64]

**Q. Do customers prefer higher fixed charges?**

A. No, they do not. The National Association of State Utility Advocates (NASUCA), which represents the interest of residential utility customers, opposes increasing fixed customer charges.[65]

**Q. How do Consumers Energy's current and proposed fixed charges compare to other Michigan gas utilities?**

A. Consumers Energy's current gas fixed customer charge is already the highest in the state. Its peers have the following fixed customer charges for their residential gas customers:

- DTE Energy: 14.50[66]
- Michigan Gas Utilities (MGU): $13.00[67]
- SEMCO Energy: $12.25[68]

[64] E.g., "Further, because lower-income customers often have a flatter load profile and use less electricity on average than other customers, they may be disproportionately affected by utility proposals – such as higher customer charges or demand charges – that seek to recover greater levels of costs from low-usage customers." Brendon Baatz, Rate Design Matters: the Intersection of Residential Rate Design and Energy Efficiency © American Council for an Energy-Efficient Economy, March 2017, p.viii under the "Rate Design Impact on Low-Income Customers" heading.

[65] See Customer Charge Resolution- 2015-1 - NASUCA.

[66] https://www.michigan.gov/mpsc/-/media/Project/Websites/mpsc/consumer/rate-books/nat-gas/dte/dtegas1curd1throughend.pdf?rev=0d2e5a793a7f4605b1e6dae4bcdde632&hash=E627FEC1432F06E7F50396F9AB683171 Sheet D-9.00

[67] https://www.michigan.gov/mpsc/-/media/Project/Websites/mpsc/consumer/rate-books/nat-gas/mgu/mgu2curd1throughend.pdf?rev=a5337ddceb424236ac5be7540e8e770f&hash=7D8FA2F83C0B7A11DFD589FA00F76FDF Sheet D-6.00

[68] https://www.michigan.gov/mpsc/-/media/Project/Websites/mpsc/consumer/rate-books/nat-gas/semco/semco01curd1throughend.pdf?rev=4a72a58597db415e8408e23123f4c0db&hash=77FB14CE6E6E4BAF83A83E0C916B1EC7 Sheet D-7.00

- Northern States Power, Wisconsin (Michigan jurisdiction): $12.00[69]
- Upper Michigan Energy Resources Company (UMERC): $5 for year-round customers, $10 for seasonal customers[70]

As such, Consumers Energy's proposed increased fixed charges would be almost 40% higher than that of DTE Energy, its closest proxy in Michigan, despite operating in relatively similar conditions with similar customer bases. There is no sufficient justification that the Company has presented for why its fixed charge should be that much higher than its peer Michigan utilities.

**Q. In light of these considerations, what is your recommendation as it relates to the Company's proposed increase to the residential fixed customer charge?**

A. Due to its regressiveness, impact on price signals, overall harm to customers (especially those who are most economically vulnerable), and significant difference from those fixed charges approved for other Michigan gas utilities, I recommend the Commission reject the Company's proposed increase to the fixed customer charge.

## X. SUMMARY OF RECOMMENDATIONS

**Q. Please summarize your conclusions and recommendations to the Commission.**

A. I recommend that the Commission:

1. Disallow $6.524M in projected increases to the Gas SCADA Project;
2. Disallow $8.21M in 2025 and $11.59M in ROM estimated spend;

[69] https://www.michigan.gov/mpsc/-/media/Project/Websites/mpsc/consumer/rate-books/nat-gas/xcel/xcel3curd1throughend.pdf?rev=272b9d1220a74fba9cb58d20e0dc98da&hash=BBEEEB41584D39CA2DDD1ED212FB1811 Sheet D-5.00

[70] https://www.michigan.gov/mpsc/consumer/natural-gas/data-price-info/natural-gas-rate-books/upper-michigan-energy-resources-corporation-mpsc-approved-natural-gas-utility-rate-books-and-cancel Sheet D-10.00

3. Disallow $57.6k in 2025 and $88.7k in 2026 for ARP-Collaboration;
4. Disallow $55.9k in 2025 and $86.9k in 2026 for ARP-LAN;
5. Disallow $1.41M in 2025 and $1.58M in 2025 for other ARP categories;
6. Disallow $126k for the Asset Accounting Tax Upgrade Project;
7. Disallow $2.65M in 2025 and $2.062M in 2026 for IT Enhancements;
8. Disallow $3.39M in the bridge period and $2.58M in the test year for Fleet Replacements;
9. Disallow $72k in Fleet O&M Responsibility Costs for EV savings;
10. Disallow $15.008M in 2025 and $15.008M in 2026 of other Fleet Responsibility costs;
11. Order the Company to prepare a more detailed analysis of its vehicle idling, as outlined earlier in my direct testimony;
12. Disallow $528k in Contact Center O&M for savings from the COST project;
13. Disallow $3.824M of Gas Operations O&M for savings from the COST project;
14. Disallow $14.937M in the bridge period and $7.199M in the test year for the Lansing Service Center;
15. Disallow $114,000 in the bridge period for the Hastings Service Center;
16. Disallow $4.38M in the bridge period and $616k in the test year for the Kalamazoo Service Center renovation; and
17. Reject the Company's proposed increase to the fixed customer charge.

My silence in regard to any position taken by the Company in its application or direct testimony in this proceeding does not indicate my endorsement of that position.

**Q. Does that complete your testimony?**

A. Yes.

(Revised Direct Testimony Bound into Confidential Record)

MS. HILLYER: Last, in lieu of cross-examination of certain Company witnesses and with the Company's agreement, I will move to admit Exhibits CUB-27, CUB-28, and CUB-29, which consists of Company responses to three discovery requests that have been uploaded to the hearing Sharepoint.

JUDGE VARCHETTI: All right. Are there any objections to the admission of the three exhibits that were just specified?

I am hearing none, so those exhibits are admitted.

MS. HILLYER: Thank you, Your Honor. I have nothing further at this time.

JUDGE VARCHETTI: All right. Thank you.

I believe that that just leaves Staff as the last remaining party.

MS. STIRLING: Thank you, Your Honor.

Staff calls to be filed the qualifications and direct testimony of Robert Nichols. That consists of a cover sheet and seven pages of questions and answers. I would note for the record that Mr. Nichols' testimony have been filed with both public

and confidential versions.

Mr. Nichols sponsored seven exhibits associated with his direct testimony. These exhibits have been marked Exhibit S-1 Schedule A-1, Exhibit S-3 Schedule C-1, Exhibit S-3 Schedule C-1.1, Exhibit S-3 Schedule C-12, Exhibit S-3 Schedule C-13, Exhibit S-10, and Exhibit S-13, which was filed under seal and contains confidential information.

The Staff moves to bind into the record the qualifications and direct testimony and to admit the exhibits of Robert Nichols.

JUDGE VARCHETTI: All right. Are there any objections to binding in the testimony of Mr. Nichols, both the public and confidential version, as well as any of his associated exhibits?

I am hearing none, so the testimony is bound into the record, and the exhibits are admitted.

(Direct Testimony and Qualifications Bound In)

**STATE OF MICHIGAN**

**BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION**

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Case No. U-21806

In the matter of the application of
**CONSUMERS ENERGY COMPANY**
for authority to increase its rates for the
distribution of natural gas and for other relief.

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# QUALIFICATIONS AND DIRECT TESTIMONY OF

# ROBERT F. NICHOLS II, CPA

# MICHIGAN PUBLIC SERVICE COMMISSION

April 23, 2025

**QUALIFICATIONS AND DIRECT TESTIMONY OF**
**ROBERT F. NICHOLS II, CPA**
**U-21806**

Q. Please state your name and business address.

A. My name is Robert F. Nichols II, and my business address is 7109 West Saginaw Highway, Lansing, MI 48917.

Q. By whom are you employed and in what capacity?

A. I am employed by the Michigan Public Service Commission (Commission or MPSC) as the Manager of the Revenue Requirements Section of the Regulated Energy Division.

Q. How long have you been employed by the MPSC and what are your duties?

A. I have been employed by the MPSC since November of 2011. As Manager of the Revenue Requirements Section, I am primarily responsible for the planning and direction of electric and gas rate case audits and presentations, as well as cases involving accounting standards and requests for accounting authority. From 2011 through March 2016, as an Auditor within the Revenue Requirements Section, my responsibilities included auditing, analyzing, and making recommendations regarding utility revenues, expenses, and rate base.

Q. Please describe your educational background.

A. I graduated from Davenport University, with highest honors, in 2009 with a Bachelor of Business Administration degree in Accounting Information Management. I attended a regulation and ratemaking conference hosted by the Michigan State University Institute of Public Utilities (MSU IPU) in May of 2012. In August of 2012, I attended the National Association of Regulatory Utility Commissioners (NARUC) annual two-week Regulatory Studies Program held at Michigan State University. Each August from 2013 through 2016 and in 2019, I attended the Annual Regulatory Studies program hosted by



VERITEXT LEGAL SOLUTIONS

MSU IPU. I also attended a one-week Advanced Regulatory Studies Program in fall of 2013, 2014, and 2016, hosted by MSU IPU.

Q. Please describe your professional background.

A. Prior to coming to the MPSC, from 2000 to 2011, I was employed by Genesee Cut Stone & Marble Company. My duties there included sales, drafting, and estimating.

Q. Do you have any professional licenses?

A. Yes. I am a Certified Public Accountant, licensed by the State of Michigan.

Q. Have you prepared testimony or assisted in any other proceedings?

A. I have assisted or filed testimony in the following cases:

| Case No. | Company | Subject/Type |
|---|---|---|
| U-16855 | Consumers Energy Co. Gas | Rate Case |
| U-16969 | SEMCO Energy Gas Company | Merger and Acquisition |
| U-16794 | Consumers Energy Co. Electric | Rate Case |
| U-16999 | Michigan Consolidated Gas Co. | Rate Case |
| U-16855 | Consumers Energy Co. Gas | Self-Implementation Refund |
| U-17087 | Consumers Energy Co. Electric | Rate Case |
| U-17197 | Consumers Energy Co. Gas | Rate Case |
| U-17273 | Michigan Gas Utilities Corp. | Rate Case |
| U-17274 | Upper Peninsula Power Co. | Rate Case |
| U-17440 | Consumers Energy Co. Electric | Self-Implementation Refund |
| U-17488 | Northern States Power Co. Gas | Rate Case |
| U-16999 | DTE Gas IRM | Reconciliation |
| U-17620 | Consumers Energy Co. | OPEB Trust Funding |
| U-17643 | Consumers Energy Co. Gas | Rate Case |
| U-17669 | WPSC Electric | Rate Case |
| U-17735 | Consumers Energy Co. Electric | Rate Case |
| U-17882 | Consumers Energy Co. Gas | Rate Case |
| U-17999 | DTE Gas Company | Rate Case |
| U-18014 | DTE Electric Company | Rate Case |
| U-17990 | Consumers Energy Co. Electric | Rate Case |
| U-18124 | Consumers Energy Co. Gas | Rate Case |
| U-18322 | Consumers Energy Co. Electric | Rate Case |
| U-18255 | DTE Electric Company | Rate Case |
| U-18370 | Indiana Michigan Power Co. | Rate Case |

| | | |
|---|---|---|
| U-18419 | DTE Electric Company | Certificate of Necessity |
| U-18424 | Consumers Energy Co. Gas | Rate Case |
| U-18999 | DTE Gas Company | Rate Case |
| U-20111 | Upper Peninsula Power Co. | TCJA Credit A Case |
| U-20268 | Alpena Power Company | TCJA Credit B Case |
| U-20134 | Consumers Energy Co. Electric | Rate Case |
| U-20287 | Consumers Energy Co. Gas | TCJA Credit B Case |
| U-20165 | Consumers Energy Co. Electric | Integrated Resource Plan |
| U-20162 | DTE Electric Company | Rate Case |
| U-20276 | Upper Peninsula Power Co. | Rate Case |
| U-20322 | Consumers Energy Co. Gas | Rate Case |
| U-20350 | Upper Peninsula Power Co. | Integrated Resource Plan |
| U-20479 | SEMCO Energy Gas Co. | Rate Case |
| U-20359 | Indiana Michigan Power Co. | Rate Case |
| U-20561 | DTE Electric Company | Rate Case |
| U-20642 | DTE Gas Company | Rate Case |
| U-20650 | Consumers Energy Co. Gas | Rate Case |
| U-20697 | Consumers Energy Co. Electric | Rate Case |
| U-20713 | DTE Electric Company | Voluntary Green Pricing |
| U-21015 | DTE Electric Company | Securitization Case |
| U-20940 | DTE Gas Company | Rate Case |
| U-20963 | Consumers Energy Co. Electric | Rate Case |
| U-21090 | Consumers Energy Co. Electric | Integrated Resource Plan |
| U-21148 | Consumers Energy Co. Gas | Rate Case |
| U-20836 | DTE Electric Company | Rate Case |
| U-20993 | Saginaw Bay Pipeline Co. | Rates for Transportation |
| U-21224 | Consumers Energy Co. Electric | Rate Case |
| U-21286 | Upper Peninsula Power Co. | Rate Case |
| U-21193 | DTE Electric Company | Integrated Resource Plan |
| U-20827 | DTE Electric Company | PSCR Reconciliation |
| U-21308 | Consumers Energy Co. Gas | Rate Case |
| U-21297 | DTE Electric Company | Rate Case |
| U-21389 | Consumers Energy Co. Electric | Rate Case |
| U-21461 | Indiana Michigan Power Co. | Rate Case |
| U-21525 | DTM Michigan Lateral Co. | Rate Request |
| U-21490 | Consumers Energy Co. Gas | Rate Case |
| U-21291 | DTE Gas Company | Rate Case |
| U-21540 | Michigan Gas Utilities Corp. | Rate Case |
| U-21555 | Upper Peninsula Power Co. | Rate Case |
| U-21534 | DTE Electric Company | Rate Case |
| U-21585 | Consumers Energy Co. Electric | Rate Case |
| U-21258 | Consumers Energy Co. Electric | PSCR Reconciliation |

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to present the MPSC Staff's (Staff) projected revenue deficiency, projected net operating income, Staff's position on the Riverside Storage, and Staff's position on the SAP S/4HANA Implementation Project O&M Deferral request for Consumers Energy Company (Consumers Energy or the Company).

Q. Are you sponsoring any exhibits?

A. Yes. I am sponsoring the following exhibits:

Exhibits:

S-1 Schedule A-1: Revenue Deficiency (Sufficiency)

S-3 Schedule C-1: Adjusted Net Operating Income

S-3 Schedule C-1.1: Development of Adjusted Net Operating Income

S-3 Schedule C-12: Income Tax Effect of Interest

S-3 Schedule C-13: Interest Synchronization Adjustment

S-10 Audit Response U21806-SA-CE 412-415 – Riverside Storage Field

S-13 **CONFIDENTIAL** SAP S/4HANA Implementation Project – Revenue Deficiency Impact of O&M Deferral

**REVENUE DEFICIENCY:**

Q. Referring to Exhibit S-1, Schedule A-1, what is Staff's projected revenue deficiency?

A. Staff projects a revenue deficiency of $177,351,000, a revenue requirement decrease of $70,657,000 from the Company's originally filed revenue deficiency of $248,008,000. Exhibit A-11 (HLR-28), Schedule A1. The main factors driving Staff's overall adjustment are Staff's lower rate base, its higher net operating income, and its lower

required rate of return. In addition to my testimony, other Staff witnesses provide testimony and supporting exhibits regarding the adjustments to the Company's revenue deficiency.

**NET OPERATING INCOME:**

Q. Referring to Exhibit S-3, Schedule C-1, what is Staff's projected net operating income?

A. Staff's projected net operating income is $558,066,000, an increase of $12,574,000 from the Company's originally filed net operating income of $545,492,000. Exhibit A-13 (HLR-36), Schedule C-1. The main factors driving Staff's overall adjustment are its increase to sales revenue and its reduction to O&M expense, depreciation expense, amortization expense, property tax expense, and general tax expense. Details of Staff's adjustments to net operating income, including the names of each Staff witness sponsoring and explaining the adjustment, can be found on Exhibit S-3, Schedule C-1.1.

**INTEREST SYNCHRONIZATION:**

Q. Please describe Exhibit S-3, Schedule C-12.

A. Exhibit S-3, Schedule C-12, shows the calculation of the tax effect of the pro-forma interest adjustment for the projected test year.

Q. Please describe Exhibit S-3, Schedule C-13.

A. Exhibit S-3, Schedule C-13, shows the calculation of the tax effect of the interest synchronization adjustment for the projected test year.

**RIVERSIDE STORAGE FIELD:**

Q. Has the Company included a regulatory asset for the Riverside Storage Field in the instant case because it was approved in MPSC Case No. U-21656 to record a regulatory

asset for the loss on the sale?

A. Yes.

Q. Has the Company indicated the sale will not be completed as currently anticipated.

A. Yes. In Audit Responses U21806-SA-CE 412 to415 (see Exhibit S-10), the Company states the buyer has terminated the agreement and the Company has also provided the impacts on the instant case.

Q. What are the impacts of the termination of the agreement on the instant case?

A. The impacts of the termination of the agreement on the instant case are as follows:

| | |
|---|---|
| Plant in Service | $11,349,000 increase |
| Depreciation Reserve | $2,293,000 increase |
| Depreciation Expense | $237,000 increase |
| Property Tax Expense | $159,000 increase |
| Working Capital | $7,398,000 decrease |
| Amortization Expense | $2,959,000 decrease |

Q. Has Staff reflected the above impacts in its revenue deficiency calculation?

A. Yes.

Q. If the Riverside Storage Field is sold, has the Company proposed to use any amounts collected in rates related to the inclusion of the Riverside Storage Field as a reduction to the established regulatory asset until rates are reset to remove the Riverside Storage Field assets from rates?

A. Yes, in audit response U21068-SA-CE 415 the Company proposed that if Riverside Storage Field is sold, it would use any amounts collected in rates related to the inclusion of the Riverside Storage Field as a reduction to the established regulatory asset until rates are reset to remove the Riverside Storage Field assets from rates. Staff supports this proposal.

**SAP S/4HANA IMPLEMENTATION PROJECT O&M DEFERRAL:**

Q. Referring to Company witness Myer's testimony at page 14-15 and Confidential Exhibit A-79 (HJM-1), does Staff support the Company's requested accounting treatment to defer [redacted] SAP S/4HANA Implementation Project O&M expense?

A. Yes, Staff supports the requested accounting treatment to defer [redacted] SAP S/4HANA Implementation Project O&M expense. Staff has recalculated the revenue deficiency impact by applying the Staff's recommended cost of capital and calculates a revenue deficiency reduction of [redacted] as found on Confidential Exhibit S-13. Staff recommends that if the Commission approves the deferral, that it recalculates the revenue deficiency impact based on its final decisions. If approved, Staff notes that this is an additional incremental revenue deficiency reduction that is not reflected in the Staff's $177,351,000 revenue deficiency found on Exhibit S-1, Schedule A-1.

**SUMMARY:**

Q. Please summarize Staff's recommendations.

A. Staff recommends 1) a projected revenue deficiency of $177,351,000, 2) a net operating income of $558,066,000, 3) including the impacts of the Riverside Storage Field sale being terminated, and 4) supports the SAP S/4HANA Implementation Projection O&M expense deferral, which is an additional incremental revenue deficiency reduction that is not reflected in the Staff's $177,351,000 projected revenue deficiency.

Q. Does this conclude your testimony?

A. Yes.

(Confidential Direct Testimony bound in in Confidential Record)

MS. STIRLING: Staff calls to be filed the qualifications and direct testimony of Justin Hecht that consists of a cover sheet and eight pages of questions and answers. Mr. Hecht sponsored five exhibits associated with his direct testimony. These exhibits have been marked Exhibit S-2, and Exhibit S-12 through Exhibit S-12.3.

Staff moves to bind into the record the qualifications and direct testimony and to admit the exhibits of Justin Hecht.

JUDGE VARCHETTI: Are there any objections to binding in the direct testimony of Mr. Hecht or any of the associated exhibits?

Hearing none, then, the testimony is bound into the record and the exhibits admitted.

(Direct Testimony and Qualifications bound in)

**S T A T E OF M I C H I G A N**

**BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION**

*** * * ***

| | | |
|---|---|---|
| In the matter of the application of | ) | |
| **CONSUMERS ENERGY COMPANY** | ) | |
| for authority to increase its rates for the | ) | Case No. U- 21806 |
| distribution of natural gas and for other relief. | ) | |
| | ) | |

# QUALIFICATIONS AND DIRECT TESTIMONY OF

# JUSTIN J. HECHT

# MICHIGAN PUBLIC SERVICE COMMISSION

**April 23, 2025**

**QUALIFICATIONS OF JUSTIN J. HECHT**
**CASE NUMBER U-21806**
**PART I**

Q. Please state your name and business address.

A. My name is Justin J. Hecht and my business address is 7109 West Saginaw Highway, Lansing, MI 48917.

Q. By whom are you employed and in what capacity?

A. I am employed by the Michigan Public Service Commission ("MPSC" or "Commission") as an auditor in the Revenue Requirements section of the Regulated Energy Division.

Q. Please briefly describe your educational background and other professional qualifications.

A. I earned a Bachelor of Business Administration Degree in Accounting from Northwood University in 2014. In February 2023, I completed the National Association of Regulatory Utility Commission ("NARUC") Rate Case Basics course. In November 2023, I completed the Institute of Public Utilities ("IPU") Advanced Regulatory Accounting and Auditing course.

Q. Please describe your professional background.

A. I was previously employed at Andrews Hooper Pavlik, PLC as a staff accountant, from November 2014 through September 2017, where I performed tax preparation and audits of financial institutions. I was previously employed at Berthiaume & Company, CPAs as an in-charge auditor, from October 2017 through January 2023, where I performed audits of governmental and nonprofit entities. I began my employment with the MPSC in February 2023 as an auditor in the Rate Base Unit of the Regulated Energy Division. My current responsibilities include, but are not limited to, performing rate case audits using

the financial and operating records of regulated utilities, applicable laws, regulations, and Commission policies to determine the necessity of rate relief.

Q. Briefly discuss your involvement with the MPSC cases.

A. I have performed audit work in the following cases:

| Case Number | Company | Case Type |
|---|---|---|
| U-21366 | MGU | Gas Rate Case |
| U-21297 | DTE Electric Company | Electric Rate Case |
| U-21389 | Consumers Energy Co. | Electric Rate Case |
| U-21412 | I&M Power Company | Depreciation Rate Case |
| U-21461 | I&M Power Company | Electric Rate Case |
| U-21384 | DTE Gas Company | Depreciation Rate Case |
| U-21291 | DTE Gas Company | Gas Rate Case |
| U-21540 | MGU | Gas Rate Case |
| U-21565 | NSPW | Electric Rate Case |
| U-21534 | DTE Electric Company | Electric Rate Case |
| U-21513 | UPPCO | Depreciation Rate Case |

Q. Have you previously sponsored testimony before the Michigan Public Service Commission?

A. Yes. I have sponsored testimony in the following cases:

| Case Number | Company | Case Type |
|---|---|---|
| U-21297 | DTE Electric Company | Electric Rate Case |
| U-21389 | Consumers Energy Co. | Electric Rate Case |
| U-21461 | I&M Power Company | Electric Rate Case |

**QUALIFICATIONS OF JUSTIN J. HECHT**
**CASE NUMBER U-21806**
**PART I**

| | | | |
|---|---|---|---|
| 1 | U-21291 | DTE Gas Company | Gas Rate Case |
| 2 | U-21540 | MGU | Gas Rate Case |
| 3 | U-21565 | NSPW | Electric Rate Case |
| 4 | U-21534 | DTE Electric Company | Electric Rate Case |

**DIRECT TESTIMONY OF JUSTIN J. HECHT**
**CASE NUMBER U-21806**
**PART II**

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to present the MPSC Staff's ("Staff") projected working capital for the 12-month period ending October 31, 2026 ("projected test year" or "test year"), and Staff's Manufactured Gas Plant (MGP) Deferred Net Unamortized Balances and MGP Amortization expense for the projected test year in the instant Consumers Energy Company ("Consumers" or the "Company") gas rate case.

Q. Are you sponsoring any exhibits in this proceeding?

A. Yes, I am sponsoring the following exhibits:

S-2 Schedule B-4: Projected Working Capital for Test Year Ending 10/31/26

S-12.0 Company Response to MPSC Staff Audit Request JJH-1

S-12.1 Company Response to MPSC Staff Audit Request JSG-1

S-12.2 Company Response to Attorney General's Fifth Discovery Request U21806-AG6-CE-0499

S-12.3 Manufactured Gas Plant Amortization Schedule & Unamortized Balance

Q. Were these exhibits prepared by you or under your direction?

A. Yes.

**Working Capital**

Q. What is the projected test year working capital being presented by Staff?

A. Referring to Staff Exhibit S-2, Schedule B-4, Line 18, Column (g), Staff presents a projected working capital of $1,367,682,000. This is a decrease of $140,699,000

from the Company's $1,508,381,000 projection presented on Exhibit A-12, B-4, Line 18, Column (p), in its initial filing.

Q. Please explain the $140,699,000 decrease.

A. The $140,699,000 decrease is the result of four adjustments made by Staff and are as follows. First, Exhibit S-2, Schedule B-4, line 8, Deferred debits, was reduced by $233,000. I will discuss this adjustment in my testimony below. Second, Exhibit S-2, Schedule B-4, line 1, Cash, cash equivalents, and restricted cash, was reduced by $5,263,000. I will discuss this adjustment in my testimony below. Third, Exhibit S-2, Schedule B-4, line 8, Deferred debits, was reduced by $7,398,000. This is the corresponding impact from Staff Witness Nichols' recommendations in his direct testimony regarding the Company's Riverside Reg Asset. Fourth, Exhibit S-2, Schedule B-4, line 14, Accrued taxes, was increased by $127,805,000. I will discuss this adjustment in my testimony below.

Q. Please explain your adjustment to reduce Exhibit S-2, Schedule B-4, line 8, Deferred debits, in the amount of $233,000.

A. Staff Exhibit S-12.0 is a response from the Company asserting that the Company inadvertently included account 1670060 Project Spartan as a utility account. It is a non-utility account as it relates to work performed associated with the sale of the ASP business. The amount of $233,000 was inadvertently included in the test year working capital for the instant case. Therefore, I've made an adjustment to reduce Deferred debits by this amount.

Q. Please explain your adjustment to reduce Exhibit S-2, Schedule B-4, line 1, Cash, cash equivalents, and restricted cash, in the amount of $5,263,000.

A. Staff Exhibit S-12.1 is a response from the Company acknowledging it used incorrect data to calculate its cash balance. Further, the Company confirms the cash balance should be $23,130,000, rather than $28,393,000 as indicated on Exhibit A-12, Schedule B-4, Line 1, Column (p), in its initial filing. Therefore, I've made an adjustment to reduce Cash, cash equivalents, and restricted cash by $5,263,000.

Q. Please explain your adjustment to increase Exhibit S-2, Schedule B-4, line 14, Accrued taxes, in the amount of $127,805,000.

A. Staff Exhibit S-12.2 is a response from the Company to the AG's Discovery acknowledging the calculation of projected accrued taxes is incorrect as filed. Further, the Company confirms the Accrued taxes balance should be $140,203,625, rather than $12,398,727 as indicated on Exhibit A-12, B-4, Line 14, Column (p) in its initial filing. Therefore, I've made an adjustment to increase Accrued taxes in the amount of $127,805,000.

**Manufactured Gas Plant (MGP)**

Q. What are Manufactured Gas Plant (MGP) costs?

A. MGP costs are expenditures incurred for the cleanup of plant sites where gas was manufactured. Manufactured gas was similar to natural gas but very dirty to produce. The plants were phased out and dismantled after the first interstate natural gas pipelines were completed and it became apparent that natural gas would not quickly run out. Even though the process of manufacturing gas was replaced by the delivery of natural gas many years ago, Consumers Energy is still responsible for the cleanup at those sites. To account for these expenditures, the

Commission approved deferred accounting, separated by vintage year, along with a ten-year amortization methodology. These costs are to be offset by any insurance recoveries, which are also to be deferred and amortized over ten years following the year of recovery. Rate recognition of the amortization expense will not occur until after a prudence review. Carrying costs will be earned on balances included in rate base after the prudence review. This deferred accounting approach was first ordered by the Commission in Case No. U-10755 on March 11, 1996 and was last reaffirmed by the Commission's December 15, 2023 order approving settlement in Case No. U-21490, Consumers Energy's most recent natural gas rate case.

Q. What is the projected test year Net Unamortized MGP being presented by Staff?

A. Referring to Staff Exhibit S-2, Schedule B-1, Line 5, Column (e), Staff presents Net Unamortized MGP of $20,438,000. This is an increase of $471,000 from the Company's $19,967,000 projection presented on Exhibit A-12, Schedule B-1, Line 5, Column (c), in its initial filing.

Q. How did Staff calculate its Net Unamortized MGP of $20,438,000?

A. Staff's Net Unamortized MGP of $20,438,000 is the direct result of incorporating Staff witness LaPan's recommendations from his prudence review of the Company's MGP remediation activities which he discusses in his direct testimony. Detailed calculations are shown on page 2 of Staff Exhibit S-12.3.

**Amortization Expense Adjustment**

Q. What adjustment to the Company's projected amortization expense are you supporting?

A. I am supporting an adjustment on Exhibit S-3, Schedule C-1.1, Line 26, Column (k), sponsored by Staff witness Nichols, to increase the Company's amortization expense by $54,000.

Q. Please explain your adjustment.

A. This $54,000 increase is the direct result of Staff using updated actual deferred expenditures through 2024 for MGP (refer to Staff Exhibit S-12.3, page 1).

Q. Does this conclude your testimony?

A. Yes.

MS. STIRLING: Staff calls to be filed the qualifications and direct testimony of Timothy Witt that consists of a cover sheet and ten pages of questions and answers. Mr. Witt sponsored three exhibits associated with his direct testimony. These exhibits have been marked Exhibit S-2 Schedule B-1, Exhibit S-18, and Exhibit S-18.1.

Staff moves to bind into the record the qualifications and direct testimony and to admit the exhibits of Timothy Witt.

JUDGE VARCHETTI: All right. Are there any objections to the admission of the direct testimony of Mr. Witt or any of the associated exhibits?

Hearing none, the testimony is bound into the record and the exhibits are admitted.

(Direct Testimony and Qualifications bound in)

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

* * * *

| | | |
|---|---|---|
| In the matter of the application of<br>**CONSUMERS ENERGY COMPANY**<br>for authority to increase its rates for the<br>distribution of natural gas and for other relief. | )<br>)<br>)<br>)<br>) | Case No. U-21806 |

**QUALIFICATIONS AND DIRECT TESTIMONY OF**

**TIMOTHY G. WITT**

**MICHIGAN PUBLIC SERVICE COMMISSION**

**April 23, 2025**

**QUALIFICATIONS OF TIMOTHY G. WITT**
CASE NUMBER U-21806
PART I

Q. Please state your name and business address.

A. My name is Timothy G. Witt and my business address is 7109 West Saginaw Highway, Lansing, MI 48917.

Q. By whom are you employed and in what capacity?

A. I am employed by the Michigan Public Service Commission ("MPSC" or "Commission") as an auditor in the Revenue Requirements Section of the Regulated Energy Division.

Q. Please briefly describe your educational background and other professional qualifications.

A. I earned a Bachelor of Business Administration Degree in Accounting from Western Michigan University in 2006. In August 2011, I completed the National Association of Regulatory Utility Commissions ("NARUC") Annual Regulatory Studies Program at Michigan State University focusing primarily on telecommunications regulation.

Q. Please describe your professional background with the MPSC.

A. I began my employment with the MPSC in January of 2011 as an auditor in the Access Restructuring Mechanism ("ARM") Fund section of the Telecommunications Division. In that position I was responsible for handling the day-to-day functions of the fund. In May of 2019, I joined the Rate Base Unit of the Revenue Requirements Section in the Regulated Energy Division as an auditor.



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**QUALIFICATIONS OF TIMOTHY G. WITT**
CASE NUMBER U-21806
PART I

Q. Briefly discuss your involvement with the MPSC cases.

A. I have performed audit work in the following cases:

| Case Number | Company | Case Type |
|---|---|---|
| U-20561 | DTE Electric Co. | Electric Rate Case |
| U-20521 | DTE Electric Co. | Demand Response |
| U-20642 | DTE Gas Co. | Gas Rate Case |
| U-20697 | Consumers Energy Co. | Electric Rate Case |
| U-20794 | Detroit Thermal LLC | Steam Rate Case |
| U-20963 | Consumers Energy Co. | Electric Rate Case |
| U-21045 | Alpena Power Company | Electric Rate Case |
| U-21148 | Consumers Energy Co. | Gas Rate Case |
| U-21224 | Consumers Energy Co. | Electric Rate Case |
| U-21286 | Upper Peninsula Power Co. | Electric Rate Case |
| U-21308 | Consumers Energy Co. | Gas Rate Case |
| U-21366 | Michigan Gas Utilities Co. | Gas Rate Case |
| U-21461 | Indiana Michigan Power Co. | Electric Rate Case |
| U-21488 | Alpena Power Co. | Electric Rate Case |
| U-21490 | Consumers Energy Co. | Gas Rate Case |
| U-21555 | Upper Peninsula Power Co. | Electric Rate Case |
| U-21585 | Consumers Energy Co. | Electric Rate Case |

Q. Have you previously sponsored testimony before the Michigan Public Service Commission?

A. Yes. I have sponsored testimony in the following cases:

**QUALIFICATIONS OF TIMOTHY G. WITT**
CASE NUMBER U-21806
PART I

| Case Number | Company | Case Type |
|---|---|---|
| U-20521 | DTE Electric Co. | Demand Response |
| U-20561 | DTE Electric Co. | Electric Rate Case |
| U-20642 | DTE Gas Co. | Gas Rate Case |
| U-20794 | Detroit Thermal LLC | Steam Rate Case |
| U-20963 | Consumers Energy Co. | Electric Rate Case |
| U-21045 | Alpena Power Company | Electric Rate Case |
| U-21148 | Consumers Energy Co. | Gas Rate Case |
| U-21224 | Consumers Energy Co. | Electric Rate Case |
| U-21286 | Upper Peninsula Power Co. | Electric Rate Case |
| U-21308 | Consumers Energy Co. | Gas Rate Case |
| U-21389 | Consumers Energy Co. | Electric Rate Case |
| U-21461 | Indiana Michigan Power Co. | Electric Rate Case |
| U-21555 | Upper Peninsula Power Co. | Electric Rate Case |
| U-21585 | Consumers Energy Co. | Electric Rate Case |

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to present MPSC Staff's ("Staff") projected rate base for the test period ending October 31, 2026 ("projected test year" or "test year") in the instant Consumers Energy Company ("Consumers Energy" or the "Company") gas rate case. Additionally, I will be supporting adjustments to the Company's projected depreciation and amortization expense, and property tax expense. These adjustments are included on Staff Exhibit S-3, Schedule C-1, sponsored by Staff witness Nichols.

Q. Are you sponsoring any exhibits in this proceeding?

A. Yes, I am sponsoring the following exhibits:

S-2 Schedule B-1: Projected Rate Base for Test Year Ending 10/31/26.

S-18.0 Company Response to Staff Audit U21806-SA-CE-246

S-18.1 Investment Impact of Corrected Depreciation Rates

Q. Were the exhibits prepared by you or under your direction?

A. Yes.

**RATE BASE**

Q. What is the total rate base being presented by Staff in the instant case for the projected test year?

A. Referring to Staff Exhibit S-2, Schedule B-1, Line 8, Column (e), Staff presents a total rate base of $11,583,831,000. This is a decrease of $166,609,000 from the Company's $11,570,740,000 projection presented on Exhibit A-12, Schedule B-1, Line 8, Column (c), in its initial filing. Below my testimony will address the individual components which result in Staff's $166,609,000 reduction to the Company's file projected rate base.

**DIRECT TESTIMONY OF TIMOTHY G. WITT**
CASE NUMBER U-21806
PART II

**Total Utility Plant**

Q. What is the total utility plant being presented by Staff for the projected test year?

A. Referring to Exhibit S-2, Schedule B-1, Line 1, Column (e), Staff presents a projected total utility plant of $14,860,353,000. This is a decrease of $46,911,000 from the Company's $14,907,264,000 projection presented on Exhibit A-12, Schedule B-1, Line 1 Column (c), in its initial filing.

Q. Please explain the $46,911,000 reduction.

A. The $46,911,000 reduction is the direct result of two adjustments made by Staff. First adjustment of $58,260,000, is the corresponding reduction to plant in service ("PIS") resulting from Staff adjustments to the Company's historic and projected capital expenditures. A summary of those adjustments and the Staff witness supporting each is illustrated in Figure 1 below. The second adjustment of $11,349,000 is an increase to plant in service for the Riverside Storage Field plant adjustment supported by Staff witness Nichols in his direct testimony.

| FIGURE 1* ($000) | | Total | Test Year Impacts From Historic and Projected Capital Spend Adj | | | | |
|---|---|---|---|---|---|---|---|
| | | Cap Ex | Plant | Accum. Depr. | Net Rate Base | Depreciation | Property Tax |
| Staff Witness | Adjustment Description | Increase / (Decrease) | Increase / (Decrease) | Increase / (Decrease) | Increase / (Decrease) | Increase / (Decrease) | Increase / (Decrease) |
| Creisher | Distribution and Transmission | (7,849) | (6,099) | (123) | (5,976) | (155) | (85) |
| Spence | Compression and Storage | (48,129) | (44,882) | (1,054) | (43,828) | (1,113) | (628) |
| Zichi | Information Technology | (4,055) | (2,915) | (439) | (2,475) | (583) | (41) |
| Klocke | Information Technology | (3,793) | (2,407) | (394) | (2,013) | (481) | (34) |
| Rueckert | LIBA | (2,388) | (1,957) | (65) | (1,892) | (54) | (27) |
| | **TOTAL** | **(66,213)** | **(58,260)** | **(2,076)** | **(56,184)** | **(2,386)** | **(816)** |

*Source - WP-TGW-1

**Depreciation Reserve**

Q. What is the depreciation reserve amount being presented by Staff for the projected test year?

A. Referring to Exhibit S-2, Schedule B-1, Line 2, Column (e), Staff presents a projected depreciation reserve of $4,645,483,000. This is a decrease of $20,230,000 from the Company's $4,665,713,000 projection presented on Exhibit A-12, Schedule B-1, Line 2, Column (c), in its initial filing.

Q. Please explain the $20,230,000 reduction.

A. The $20,230,000 reduction is the direct result of three adjustments made by Staff. The first adjustment, a reduction of $2,075,900, is the corresponding impact on the depreciation reserve resulting from Staff's adjustments to the Company's historic and projected capital expenditures (refer to Figure 1 on page 5 of my testimony.) The second adjustment a reduction of $20,447,000, is made to correct an error by the Company. In response to audit request TGW-1 (U21806-SA-CE-246) the company confirms that the depreciation expense and depreciation reserve, as filed, were inadvertently derived using incorrect depreciation rates. Applying the correct depreciation rates results in a $20,447,000 reduction to the depreciation reserve. Refer to Staff Exhibit S-18.1. The third adjustment, an increase to the depreciation reserve of $2,293,000, is related to the Riverside Storage Field plant adjustment supported by Staff witness Nichols in his direct testimony.

**Net Unamortized MGP**

Q. What is the Net Unamortized MGP amount being presented by Staff for the projected test year?

A. Referring to Exhibit S-2, Schedule B-1, Line 5, Column (e), Staff presents a projected Net Unamortized MGP of $20,438,000. This is an increase of $471,000 from the Company's $19,967,000 projection presented on Exhibit A-12, Schedule B-1, Line 5, Column (c), in its initial filing, and is supported by Staff witness Hecht in his direct testimony.

**Working Capital**

Q. What is the amount working capital being presented by Staff for the projected test year?

A. Referring to Exhibit S-2, Schedule B-1, Line 7, Column (e), Staff presents a projected working capital of $1,367,682,000. This is a decrease of $140,699,000 from the Company's $1,508.381,000 projection presented on Exhibit A-12, Schedule B-1, Line 7, Column (c), in its initial filing, and is supported by Staff witness Hecht in his direct testimony.

**DEPRECIATION AND AMORTIZATION EXPENSE ADJUSTMENT**

**Depreciation Expense:**

Q. What adjustment to the Company's test year projected depreciation are you supporting?

A. I am supporting an adjustment on Exhibit S-3, Schedule C-1, Line 9, Column (d), sponsored by Staff witness Nichols, to decrease the Company's test year projection by $11,005,000.

Q. Please explain the $11,005,000 reduction.

A. The $11,005,000 reduction is comprised of three items. The first is a decrease of $2,386,000 which is the corresponding impact on depreciation and amortization expense resulting from Staff adjustments to the Company's historic and projected capital expenditures (refer to Figure 1 on page 5 of my testimony). The second adjustment, a decrease of $8,856,000, is related to the use of incorrect depreciation rates by the Company as discussed earlier in my testimony. Refer to Staff Exhibit S-18.1. The third adjustment, an increase of $237,000, is related to the Riverside Storage Field plant adjustment supported by Staff witness Nichols in his direct testimony.

**Amortization Expense:**

Q. What adjustment to the Company's test year projected Amortization Expense are you supporting?

A. I am supporting an adjustment on Exhibit S-3, Schedule C-1, Line 10, Column (d), sponsored by Staff witness Nichols, to decrease the Company's test year projection by $2,905,000.

Q. Please explain the $2,905,000 reduction.

A. The $2,905,000 reduction is comprised of two items. The first is a reduction of $2,959,000 and is related to the Riverside Storage Field plant adjustment supported by Staff witness Nichols in his direct testimony. The second is an increase of $54,000 and is related to the amortization of MGP supported by Staff witness Hecht in his direct testimony.

**PROPERTY TAX EXPENSE ADJUSTMENT**

Q. What adjustment to the Company's test year projected property tax expense are you supporting?

A. I am supporting an adjustment on Exhibit S-3, Schedule C-1, Line 11, Column (d) sponsored by Staff witness Nichols, to decrease the Company's test year projection by $657,000.

Q. Please explain the $657,000 reduction.

A. The $657,000 reduction is comprised of two adjustments, The first adjustment, a reduction of $816,000 is the corresponding impact on property tax expense resulting from the test year plant impacts of Staff's adjustments to the Company's historic and projected capital expenditures (refer to Figure 1 on page 5 of my testimony) multiplied by the Company's property tax rate of 1.3998859% from Company Exhibit A-99 (BJV-1). The second adjustment, an increase of $159,000, is related to the Riverside Storage Field plant adjustment supported by Staff witness Nichols in his direct testimony.

Q. Why did you incorporate this adjustment as part of the test year impacts resulting from Staff's adjustments to the Company's historic and projected capital expenditures?

A. The Company's projected property tax expense is developed, in part, by using its projected plant balances. Since Staff's capital expenditure adjustments result in a decrease to the Company's projected test year plant balance, a corresponding adjustment is needed to decrease the projected test year property tax expense.

**SUMMARY OF RECOMMENDATIONS**

Q. Please summarize your recommendations.

A. I recommend the ALJ and Commission approve the following based on Staff's adjustments: Staff's projected rate base of $11,583,831,000, Staff's $11,005,000 reduction to depreciation expense, Staff's $2,905,000 reduction to amortization expense, and Staff's $657,000 reduction to the property tax expense. Specifically, my testimony supports a $166,909,000 reduction to the Company's projected rate base, a reduction to total utility plant of $46,911,000, a reduction to depreciation reserve of $20,230,000, a reduction to depreciation expense of $11,005,000, a reduction to amortization expense of $2,905,000, and a reduction to property tax expense of $657,000.

Q. Does this conclude your testimony?

A. Yes.

MS. STIRLING: Staff calls to be filed the qualifications and direct testimony of Michelle Schreur that consists of a cover sheet and three pages of questions and answers. Ms. Schreur sponsored one exhibit associated with her direct testimony. This exhibit has been marked Exhibit S-3 Schedule C-5.

Staff moves to bind into the record the qualifications and direct testimony and to admit the exhibit of Michelle Schreur.

JUDGE VARCHETTI: Any objections to the binding in of Ms. Schreur's direct testimony or the associated exhibit?

Hearing none, then, the testimony is bound into the record and the exhibit is admitted.

(Direct Testimony and Qualifications bound in)

**STATE OF MICHIGAN**

**BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION**

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Case No. U-21806

In the matter of the application of
**CONSUMERS ENERGY COMPANY**
for authority to increase its rates for the
distribution of natural gas and for other relief.

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# QUALIFICATIONS AND DIRECT TESTIMONY OF

# MICHELLE L. SCHREUR

# MICHIGAN PUBLIC SERVICE COMMISSION

April 23, 2025

**QUALIFICATIONS AND DIRECT TESTIMONY OF**
**MICHELLE L. SCHREUR**
**U-21806**

Q. Please state your name and business address.

A. My name is Michelle L. Schreur and my business address is 7109 West Saginaw Highway, Lansing, MI 48917.

Q. By whom are you employed and in what capacity?

A. I am employed by the Michigan Public Service Commission (MPSC or Commission) as Manager of the Income Analysis Unit in the Revenue Requirements section of the Regulated Energy Division.

Q. Please describe your educational background.

A. I graduated from Grand Rapids Community College in 2015 with an Associate Degree in Business Administration. In 2017, I graduated from Grand Valley State University with a Bachelor of Business Administration Degree in Accounting and Finance.

Q. Please describe your professional background with the MPSC.

A. I began my employment with the MPSC in September of 2017 as an auditor in the Revenue Requirements section of the Regulated Energy Division. In that position my responsibilities included, but were not limited to, performing rate case audits using the financial and operating records of regulated utilities, applicable laws, regulations, and Commission policies to determine the necessity of rate relief. In August 2022, I was promoted to my current position as Manager of the Income Analysis Unit in the Revenue Requirements Section of the Regulated Energy Division.

Q. Have you received ongoing training since joining the MPSC?

A. Yes. In September of 2017, I attended a Utility Business Model/Financial Valuation Training hosted by Michigan State University Institute of Public Utilities (MSU IPU). In



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August of 2018, I attended a fundamental and intermediate Annual Regulatory Studies Program hosted by MSU IPU.

Q. Have you previously sponsored testimony under that name Michelle L. Edelyn?

A. Yes.

Q. Have you previously sponsored testimony before the Michigan Public Service Commission?

A. Yes. I have sponsored testimony in the following cases:

| Case Number | Company | Case Type |
|---|---|---|
| U-18424 | Consumers Energy Co. | Gas Rate Case |
| U-18999 | DTE Gas Co. | Gas Rate Case |
| U-20162 | DTE Electric Co. | Electric Rate Case |
| U-20276 | Upper Peninsula Power Co. | Electric Rate Case |
| U-20322 | Consumers Energy Co. | Gas Rate Case |
| U-20479 | SEMCO Energy Gas Co. | Gas Rate Case |
| U-20561 | DTE Electric Co. | Electric Rate Case |
| U-20563 | Consumers Energy Co. | DR Reconciliation |
| U-20650 | Consumers Energy Co. | Gas Rate Case |
| U-20940 | DTE Gas Co. | Gas Rate Case |
| U-20836 | DTE Electric Co. | Electric Rate Case |
| U-21286 | Upper Peninsula Power Co. | Electric Rate Case |
| U-21308 | Consumers Energy Co. | Gas Rate Case |
| U-21389 | Consumers Energy Co. | Electric Rate Case |
| U-21461 | Indiana Michigan Power Co. | Electric Rate Case |
| U-21540 | Michigan Gas Utilities | Gas Rate Case |
| U-21585 | Consumers Energy Co. | Electric Rate Case |

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to present MPSC Staff's (Staff) overall Operations and Maintenance (O&M) Expense Projection for the 12-month period ending October 31, 2026 (projected test year) in the instant Consumers Energy Company (Consumers or the Company) rate case.

Q. Are you sponsoring any exhibits in this proceeding?

A. Yes. I am sponsoring the following exhibits:

S-3 Schedule C-5: Projected Operations and Maintenance (O&M) Expense for the Test Year Ending October 31, 2026

Q. Was this exhibit prepared by you or under your direction?

A. Yes.

**Projected O&M Expense**

Q. Please describe Exhibit S-3, Schedule C5.

A. Exhibit S-3, Schedule C5, presents Staff's O&M Expense Projection of $296,906,000 for the 12-month period ending October 31, 2026, a decrease of $998,000 from the total Company's projection of $297,904,000. Staff's projections were developed through the categories listed in column (a). Column (c) presents the Company's Projection and column (e) presents Staff's Projection, with the difference shown in column (d). The differences in column (d) represent Staff adjustments and are supported by corresponding Sources listed in column (b). A reconciliation by Expense, Amount, and Witness is shown at the bottom of the exhibit.

Q. Does this conclude your testimony?

A. Yes.

MS. STIRLING: Staff calls to be filed the qualifications and direct testimony of Kirk Megginson that consists of a cover sheet and 38 pages of questions and answers. Mr. Megginson sponsored one exhibit with six schedules associated with his direct testimony. These exhibits have been marked Exhibit S-4 Schedules D-1 through D-6.

Staff moves to bind into the record the qualifications and direct testimony and to admit the exhibits of Kirk Megginson.

JUDGE VARCHETTI: Are there any objections to binding in the direct testimony of Mr. Megginson or the associated exhibit and schedules?

Hearing none, the testimony is bound into the record and the exhibit admitted.

(Direct Testimony and Qualifications bound in)

STATE OF MICHIGAN

**BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION**

*** * * ***

| | | |
|---|---|---|
| **In the matter of the application of** | **)** | |
| **CONSUMERS ENERGY COMPANY** | **)** | |
| **for authority to increase its rates for the** | **)** | **Case No. U-21806** |
| **distribution of natural gas and for other relief.** | **)** | |
| | **)** | |

**QUALIFICATIONS AND DIRECT TESTIMONY OF**

**KIRK D. MEGGINSON**

**MICHIGAN PUBLIC SERVICE COMMISSION**

**April 23, 2025**

**QUALIFICATIONS OF KIRK D. MEGGINSON**
**CASE NUMBER U-21806**
**PART I**

Q. Please state your name, business address and occupation.

A. My name is Kirk D. Megginson and my business address is 7109 West Saginaw Highway, Lansing, MI 48917. I am employed by the Michigan Public Service Commission (MPSC or Commission) as a Financial Specialist in the Revenue Requirements Section of the Regulated Energy Division.

Q. Please describe your educational and professional background.

A. I graduated with a Bachelor of Science degree in Mechanical Engineering from Michigan State University in March 1991 and received my Master of Business Administration degree with a concentration in Finance from Clark Atlanta University in May 2002.

From 1991 to 2000, I worked for the Michigan Consolidated Gas Company as an account manager, primarily responsible for managing the natural gas transportation accounts of industrial and commercial clients in Wayne and Washtenaw counties.

In December 2002, I began work as a Financial Analyst at the MPSC. As a Financial Analyst, I analyzed and reported on the financial statistics of regulated Michigan jurisdictional utility companies and assisted the MPSC Revenue Requirements section in utility rate case hearings. In October 2008, I transitioned to a Financial Specialist and currently provide Staff with expert testimony on capital structure development, debt and equity costing, business and credit risk analysis, and other finance-related issues in rate case proceedings.

Q. Have you received ongoing training since joining the MPSC?



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**QUALIFICATIONS OF KIRK D. MEGGINSON**
**CASE NUMBER U-21806**
**PART I**

A. Yes. In addition to my academic training, I have attended several seminars and workshops on electric and gas utility financial analysis, credit risk and rating analysis and tax, accounting and auditing methodology while employed at the MPSC. In August 2003, I attended the introductory two-week regulatory studies program offered by the Michigan State University, Institute of Public Utilities, which covered various aspects of utility regulation and energy sector fundamentals. I attend assorted segments of the regulatory studies program and other related seminars as necessary and practical. I have also attended training sessions provided by Standard & Poor's on credit rating development, credit risk and on regulatory finance provided by industry experts.

Q. Have you participated in other rate increase cases prior to this case?

A. Yes, I have. I have participated in the following rate increase request cases:

| Case Number | Company Name | Description |
|---|---|---|
| U-13470 | Michigan Gas Utilities | Capital Structure |
| U-13575 | SEMCO Gas Co. | Capital Structure |
| U-13688 | Wisconsin Public Service Corp. | Capital Structure |
| U-14838 | Detroit Edison Co. | Capital Structure/Debt Cost Rate |
| U-14893 | SEMCO Energy Co. | Capital Structure/Cost of Capital |
| U-15190 | Consumers Energy (Gas Div.) | Capital Structure/Cost of Capital |
| U-15245 | Consumers Energy (Electric Div.) | Capital Structure/Cost of Capital |
| U-15506 | Consumers Energy (Gas Div.) | Capital Structure/Cost of Capital |
| U-15985 | Michigan Consolidated Gas Co. | Capital Structure/Cost of Capital |
| U-15986 | Consumers Energy (Gas Div.) | Capital Structure/Cost of Capital |
| U-16191 | Consumers Energy (Electric Div.) | DOE Liability Trust Fund |
| U-16418 | Consumers Energy (Gas Div.) | ROE Recommendation |
| U-16472 | Detroit Edison Co. | ROE Recommendation |



VERITEXT LEGAL SOLUTIONS

**QUALIFICATIONS OF KIRK D. MEGGINSON**
**CASE NUMBER U-21806**
**PART I**

| | | | |
|---|---|---|---|
| 1 | U-16794 | Consumers Energy (Electric Div.) | ROE Recommendation |
| 2 | U-17197 | Consumers Energy (Gas Div.) | Cost of Capital (case withdrawn) |
| 3 | U-17643 | Consumers Energy (Gas Div.) | Capital Structure/Cost of Capital |
| 4 | U-17735 | Consumers Energy (Electric Div.) | Capital Structure/Cost of Capital |
| 5 | U-17880 | Michigan Gas Utilities | Capital Structure/Cost of Capital |
| 6 | U-17882 | Consumers Energy (Gas Div.) | Capital Structure/Cost of Capital |
| 7 | U-17895 | Upper Peninsula Power Co. | Capital Structure/Cost of Capital |
| 8 | U-17990 | Consumers Energy (Electric Div.) | Capital Structure/Cost of Capital |
| 9 | U-17999 | DTE Energy (Gas Div.) | Capital Structure/Cost of Capital |
| 10 | U-18014 | DTE Energy (Electric Div.) | Capital Structure/Cost of Capital |
| 11 | U-18124 | Consumers Energy (Gas Div.) | Capital Structure/Cost of Capital |
| 12 | U-18370 | Indiana-Michigan Power Co. | Capital Structure/Cost of Capital |
| 13 | U-18255 | DTE Electric | Capital Structure/Cost of Capital |
| 14 | U-18424 | Consumers Energy (Gas Div.) | Capital Structure/Cost of Capital |
| 15 | U-18999 | DTE Gas | Capital Structure/Cost of Capital |
| 16 | U-20134 | Consumers Energy (Electric Div.) | Capital Structure/Cost of Capital |
| 17 | U-20322 | Consumers Energy (Gas Div.) | Capital Structure/Cost of Capital |
| 18 | U-20561 | DTE Electric | Cost of Capital |
| 19 | U-20650 | Consumers Energy (Gas Div.) | Capital Structure/Cost of Capital |
| 20 | U-20697 | Consumers Energy (Electric Div.) | Capital Structure/Cost of Capital |
| 21 | U-20963 | Consumers Energy (Electric Div.) | Capital Structure/Cost of Capital |
| 22 | U-21148 | Consumers Energy (Gas Div.) | Capital Structure/Cost of Capital |
| 23 | U-21224 | Consumers Energy (Electric Div.) | Capital Structure/Cost of Capital |
| 24 | U-21286 | Upper Peninsula Power Co. | Capital Structure/Cost of Capital |
| 25 | U-21308 | Consumers Energy (Gas Div.) | Capital Structure/Cost of Capital |
| 26 | U-21389 | Consumers Energy (Electric Div.) | Capital Structure/Cost of Capital |
| 27 | U-21490 | Consumers Energy (Gas Div.) | Capital Structure/Cost of Capital |
| 28 | U-21585 | Consumers Energy (Electric Div.) | Capital Structure/Cost of Capital |



VERITEXT LEGAL SOLUTIONS

**DIRECT TESTIMONY OF KIRK D. MEGGINSON**
**CASE NUMBER U-21806**
**PART II**

Q. What is the purpose of your testimony in this proceeding?

A. The purpose of my testimony is to provide a recommendation on behalf of the Michigan Public Service Commission Staff (Staff) regarding the recommended capital structure, return on common equity (ROE) and overall rate of return that Consumers Energy Company (Consumers Energy, Consumers or the Company) should be allowed to earn on its Michigan jurisdictional gas utility investment. The recommendations provided in this testimony are based on a large degree of professional judgment and technical expertise in the area of financial analysis.

Q. Are you supporting any exhibits on behalf of Staff in this proceeding?

A. Yes. I am supporting Staff Exhibit S-4; Schedules D-1 through D-6:

| Schedule | Page | Title |
|---|---|---|
| D-1 | 1 | Recommended Test Year Overall Rate of Return |
| D-2 | 1 | Long-Term Debt Balance and Cost Rate |
| D-3 | 1 | Short-Term Debt Balance and Cost Rate |
| D-4 | 1 | Preferred Stock Balance and Cost Rate |
| D-5 | 1 | Projected Common Equity Balance |
| D-5 | 2 | Gas Utility Proxy Group Corporate Statistics |
| D-5 | 3 | Proxy Group Credit Rating's Criteria |
| D-5 | 4 | Gas Proxy Group Return on Common Equity |
| D-5 | 5 | Discounted Cash Flow Model (DCF) Analysis |
| D-5 | 6 | SBBI Historical Market Risk Premium Development |
| D-5 | 7 | Historical Capital Asset Pricing Model (CAPM) Analysis |
| D-5 | 8 | Projected CAPM – Damodaran Trailing 12-mth MRP Analysis |
| D-5 | 9 | Projected CAPM – Damodaran 10-year (smoothed) MRP Analysis |
| D-5 | 10 | Dow Jones Utility Average Year 2000 - 2024 |
| D-5 | 11 | Gas Utility Historical Market Return & Bond Yield |
| D-5 | 12 | Bond Yield + Risk Premium Model Analysis |

| | | | |
|---|---|---|---|
| | D-5 | 13 | Other State Commission ROE Decisions 2022-2024 |
| | D-5 | 14 | Cost of Equity Range and ROE Recommendation |
| | D-6 | 1 | CE – Reg. Assets audit response from U-21148 |
| | D-6 | 1 | CE – Cash on Hand/ST-Debt audit response |

Q. Was the proposed Exhibit S-4 prepared by you and/or under your direction?

A. Yes, it was.

Q. Please summarize Staff's ROE recommendation.

A. Staff recommends a return on equity of 9.75%, which is the midpoint of Staff's 9.25% - 10.25% ROE range. To aid in the determination of a fair ROE for the Company, and since Consumers Energy's Gas Division isn't publicly traded, a group of eight publicly traded gas and/or gas-electric utility companies were used as a comparable proxy to the Company. The proxy group's data was used in the traditional Discounted Cash Flow (DCF) and Capital Asset Pricing Model (CAPM) return on equity estimates. In addition to those traditional models, a Bond Yield + Risk Premium analysis and a review of gas ROE authorizations from other state jurisdictions from 2022-2024 was also used in this case. Staff's 9.75% ROE recommendation considers Consumers Energy's Gas Division's currently authorized 9.90% ROE and the Company's 10.25% ROE request as outlined in its application.

Q. How is your testimony structured?

A. My testimony is structured in two parts. Part I corresponds to my Exhibit S-4, Schedules D-1 through D-4 exhibits, which describe all of the ratemaking capital structure components and their cost rates other than common equity. Part II

describes my recommended common equity balance and cost of equity recommendation and corresponds with my Schedule D-5 exhibits.

Q. Please start by outlining Consumers Energy's current credit rating.

A. Most of Consumers Energy's long-term debt is in the form of first mortgage bonds that the rating agencies label as senior secured debt. The senior secured debt rating is the first rating shown on the Company's Exhibit A-30, page 1 of 1 provided by witness Marc Bleckman. Standard & Poor's (S&P) rates Consumers Energy's senior secured debt "A", which was raised from "A-" on December 4, 2014. Moody's rates Consumers senior secured debt "A1", which was lowered from "Aa3" in May 2021. Fitch rates Consumers senior secured debt "A+", which was raised two notches from "A-" in March 2016.

Q. Has Consumers credit rating been stable over the years?

A. Yes. As noted earlier, S&P has held the Company's credit rating steady for approximately 10 years and Fitch has held it steady for over eight years. Moody's one notch downward revision from Aa3 (equivalent to S&P's AA- rating) in 2021 put the Company's credit rating more in line with the other two agencies ratings. The prior Moody's rating appeared to be an outlier.

Q. Please outline some of the recent ratings agency comments on Consumers credit rating and corporate outlook.

A. In S&P's August 2024 report, the agency stated "We believe Michigan's regulatory construct as above average compared to peers because of the benefit of a streamlined 10-month rate case process. Other constructive rate mechanisms include the use of forward test-years, power supply cost rider adjustments, and

natural gas cost rider adjustments. These mechanisms help the company earn its allowed ROE and minimize regulatory lag. The stable rating outlook on Consumers reflects our expectation that management will focus on its core utility operations and reach constructive regulatory outcomes to avoid increasing business risk"[1] In Moody's May 31, 2024, ratings report, the agency remarked "Consumers Energy is regulated in Michigan by the MPSC, which has a regulatory framework that we view to be more credit supportive than most other states. As a result of the 2008 and 2016 energy legislation in Michigan, the regulatory framework was streamlined, improving both the rate case process and the timeliness of cost recovery. The stable outlook reflects our expectation that financial metrics will remain stable, and that Consumers Energy will continue to benefit from a consistent and generally credit supportive regulatory environment. Gas utilities in the state also benefit from programs designed to assure recovery of needed infrastructure improvements. Consumer Energy's enhanced infrastructure replacement program (EIRP) is a MPSC authorized 25-year incremental investment program to upgrade natural gas infrastructure."[2] Fitch's April 22, 2024, credit assessment noted "Fitch believes the regulatory environment in Michigan remains mostly constructive from a credit perspective. The regulatory framework allows for full pass-through of fuel costs and purchased power, forward-looking test years and a timely 10-month review period for general rate case resolution."[3] Thus, the credit rating agencies acknowledge that Consumers

[1] S&P Global – Ratings Direct (Aug. 20, 2024)
[2] Moody's Investor Services – Credit Opinion (31 May 2024)
[3] Fitch Ratings-Consumers Energy Company (22-Apr-2024)

currently has a steady and stable foundation for its credit rating, and that Michigan has a very equitable regulatory environment that is supportive of a utility's ongoing business and financial health.

Q. Have other entities commented on the supportive regulatory environment here in Michigan?

A. Yes. According to S&P's Regulatory Research Associates (RRA), the Michigan commission is rated Average/1, which is in the upper tier of the national average, in terms of utility credit supportive regulation. Michigan's regulation was recently reduced from Above Average/3 to Average/1 in July 2024. RRA noted that Michigan regulation remains more constructive than average from an investor point of view, but outcomes of certain recent rate case proceedings indicated a potential tightening in the regulatory climate.[4] The Commission has been rated in the top tier for a number of years now and the Commission has proactively considered the health and welfare of Consumers Energy and the other regulated utilities here in Michigan through its many orders. To that end, the Company has had steady earnings over the years and earnings have generally grown the past few years. Staff asked Consumers in an audit request to provide its net income from 2010 to most recent and the percent that the net income either rose or fell from the previous year. The Company responded by providing the following chart.

[4] S&P Global – RRA State Regulatory Evaluations and RRA State Commission Profiles (Jan. 2025) and (7/31/2024)

| | Consumers Energy Net Income (In Millions) | % Increase Over Previous Year |
|---|---|---|
| **2024** | 1,007 | 16.0% |
| **2023** | 865 | -8.0% |
| **2022** | 945 | 9.1% |
| **2021** | 866 | 6.4% |
| **2020** | 814 | 9.8% |
| **2019** | 741 | 5.4% |
| **2018** | 703 | 12.0% |
| **2017** | 630 | 3.0% |
| **2016** | 614 | 4.0% |
| **2015** | 592 | 5.0% |
| **2014** | 565 | 6.0% |
| **2013** | 532 | 22.0% |
| **2012** | 437 | -6.0% |
| **2011** | 465 | 8.0% |
| **2010** | 432 | 48.0% |

From the chart, you can see that the Company's net income has risen steadily over the years, with lower earnings in only two of the past fifteen years. This has enabled Consumers to access credit markets to the tune of billions in short and long-term financing at very competitive rates. According to the Company witness Bleckman's Exhibit No. A-31, which outlines recent country-wide utility debt issuances, Consumers issued $500 million in unsecured debt in July 2023 and $700 million of secured debt in July 2024 at very favorable rates and credit spreads. Those issuances show that the Company's ability to secure low to moderately priced debt has not been negatively impacted, even with the Moody's revision in 2021. Consumers anticipates around two billion in long-term debt issuances in this rate case alone, which does not suggest an inability or

unwillingness to borrow. To that end, Staff's 9.75% ROE recommendation represents a fair if not favorable return for the Company.

Q. Does Consumers Energy have regulatory provisions in place that impact or can impact its credit rating?

A. Yes, in a positive manner. Consumers currently has a revenue decoupling mechanism in place that allows it to collect revenues, including a return on investment, that is unrelated to the amount of gas sold to its customer base. The decoupling mechanism promotes revenue stability. The Company also has several gas infrastructure improvement and replacement programs in place with surcharge payment mechanisms. These programs have the benefit of improving the Company's cash flow expectancy and thus, substantially reduce the Company's risk. This risk reduction should entail a modest reduction in the Company's required ROE.

Q. The Company stresses the importance of certain credit metrics, namely its funds from operations to debt ratio (FFO-to-Debt) metric. How has the rating agencies assessed this metric for Consumers in their most recent credit opinions?

A. S&P, in its most recent August 2024 ratings snapshot, noted **"We expect CE will maintain stand-alone financial measures consistent with the middle of the range for its financial risk profile category, specifically FFO to debt of about 17%-19%."** S&P noted that its rating could be negatively impacted if Consumers FFO-to-Debt ratio fell consistently below 15% in the future. S&P anticipates above threshold FFO-to-Debt ratios for Consumers in the foreseeable future. Moody's, in its May 2024 report, noted "**We expect Consumers Energy**

**to maintain a stable financial profile with cash flow from operations before changes in working capital, its CFO pre-WC to debt (Moody's FFO-to-Debt term) averaging around 20 -21% over the next 2-3 years."** Moody's also notes that Consumers rating was impacted by the parent company's significant debt profile, but that the parents' percentage of debt had reduced notably in recent years. Moody's also noted that if Michigan's regulatory framework became more formulaic, transparent and timely, with its suite of cost recovery mechanisms for Consumers, then a ratings upgrade was possible. Fitch, in its April 2024 credit opinion, noted that "Consumers FFO leverage will remain well within sensitivities, averaging 4.1x through 2028. (Fitch notes that FFO leverage that exceeds 4.5x on a sustained basis, could lead to a negative ratings action.)

Thus, ratings agencies don't foresee any major deterioration or long-lasting decline in the FFO-to-Debt ratio for Consumers Energy in the foreseeable future. A sustained decline in the FFO-to-Debt metric, along with other negative developments, could bring about a ratings' action from the ratings agencies but none are anticipated. Any suggestion of imminent decay of the FFO-to-Debt metric by the Company does not stand up to scrutiny and should be rejected by the Commission.

**Part I. Capital Structure Balance and Component Cost Development**

Q. Please start by summarizing the ratemaking capital structure balances recommended by the Company and by Staff.

A. The following chart outlines the capital structure balances recommended by the Company and Staff:

Chart 1.

| Components (000) | Company | Staff |
|---|---|---|
| Long-Term Debt | 12,645,000 | 12,840,150 |
| Preferred Stock | 37,315 | 37,315 |
| Common Equity | 13,070,000 | 12,875,255 |
| Short-Term Debt | 201,400 | 201,400 |
| Deferred FIT | 4,629,000 | 4,629,000 |
| Job Development Investment Tax Credits | 114,000 | 114,000 |

According to Chart 1, Staff agrees with most of the Company's recommended balances except for long-term debt and common equity.

Q. Please explain Staff's long-term debt balance recommendation and how it differs from the Company's recommendation.

A. Staff agreed with the Company's long-term debt balance as shown in the Company's Exhibit A-14, Schedule D-2, but with some modification. I modified the Company's capital structure by $390 million to balance the Company's capital structure to the 50/50 standard that Staff recommends. To that end, I added $195 million to Company's long-term debt balance, modifying it from $12,645 million to $12,840 million. The result is a LT-debt balance of 49.86% of the permanent capital structure.

Q. Please explain Staff's recommended common equity balance and how it differs from the Company's recommendation.

A. I adopted the Company's common equity balance through October 2026 of $13,035 million. I then modified the Company's equity balance to apply Staff's 50/50 capital structure standard and reduced the Company's equity balance by $160 million. This resulted to a ratemaking common equity balance of $12,875 million and an equity capital structure ratio of 50.0%.

Q. Why did you modify the Company's LT-debt and common equity balances?

A. For a few reasons. To start, the Company complained in prior rate cases that Staff was uneven in its balancing implementation by just adjusting the equity balance alone in the Company's ratemaking capital structure and not allowing the Company its full capital allocation request. Though Staff believes the Company's complaints were unfounded[5], Staff has modified its approach to eliminate future dispute. Second, the Commission has provided detailed commentary with respect to the Company's ratemaking capital structure. For example, the Commission stated in its December 22, 2021, Order in Case No. U-20963:

> …the Commission believes a capital structure that is roughly balanced between debt and equity strikes the appropriate balance between ensuring access to capital at attractive rates, on the one hand, and maintaining customer affordability on the other.[6]

Additionally, the Commission remarked in its September 26, 2019 Order in Consumers Energy's Gas Case No. U-20322:

[5] Consumers, in all its recent gas and electric rate cases, has projected no less than four, 30-year debt issuances per case. However, the Company's last 30-year debt issuance was in August 2022. Thus, the Company has been inconsistent in its LT-debt issuance maturity and amounts compared to rate case requests. This inconsistency renders the Company's arguments of unfair treatment moot.
[6] MPSC Case No. U-20963, 12/22/2021 Order, p 220

The Commission continues to find that Consumers' treatment as a stand-alone company for ratemaking purposes requires it to maintain a capital structure that is evenly balanced between debt and equity.[7]

The Commission had earlier addressed the equity layer issue in its February 2017 Order in Consumers Energy's Electric Case No. U-17990. In that order, the Commission stated:

> The Commission desires to arrive at an optimized capital structure that is both supportive of planned infrastructure investments yet is not unnecessarily burdensome on ratepayers. The Commission also anticipates that a cycle of heavier-than-usual investment will present an ideal opportunity to rebalance Consumers' capital structure to reach its 50/50 goal[8].

A few months later, the Commission, in its July 2017 Order in Consumers Energy's Case. No. U-18124, stated:

> (The Commission) disagrees with Consumers that its proposed capital structure is sufficiently balanced to avoid scrutiny. The Commission cannot overemphasize the company's responsibility to rebalance its equity and debt capital. [9]

Those orders highlight the Commission's legitimate concern with the size and makeup of the Company's ratemaking capital structure at the time. The Commission desires a 50/50 capital structure from the Company and Staff hopes the Company will submit a balanced capital structure on its own accord in a future rate proceeding. Until that time, Staff's 50/50 capital structure recommendation fully supports the Commission's objective of equilibrium that is less costly to ratepayers and yet still reasonable for the Company to maintain its wide access to capital markets.

[7] MPSC Case No. U-20322, 9/26/2019 Order, p 62
[8] MPSC Case No. U-17990, 2/28/2017 Order, p 64
[9] MPSC Case No. U-18124, 7/31/2017 Order, p 45- 46.

Q. Have other intervenors recommended a balanced capital structure for Consumers in previous rate cases?

A. Yes. The Attorney General (AG) has recommended a 50/50 capital structure for Consumers Energy in most of the past rate cases. The Association of Businesses Advocating Tariff Equity (ABATE) has also advocated for a 50% ratemaking equity level in previous rate cases.[10] Thus, several intervenors understand the importance of an evenly split capital structure that is more fair and less costly to ratepayers.

Q. You state that common equity is costlier to ratepayers than debt, can you illustrate that point?

A. Yes. Based on the Company's embedded historical debt schedule ending December 2023, the Company's average long-term debt cost was 4.00%.[11] Thus, for every dollar of debt in the capital structure, it cost ratepayers approximately 4.0 cents. For equity, Staff uses Consumers pre- and post-tax reform table in its TCJA presentation in the gas rate Case No. U-18424. The table below is:

*Pre-Tax ROE = ROE / (1 – Tax Rate)*

| | Pre-Tax Reform | Post-Tax Reform |
|---|---|---|
| Authorized ROE | 9.90% | 9.90% |
| Tax Rate | 35.0% | 21.0% |
| Pre-Tax ROE | 15.23% | 12.53% |

Hence, prior to tax reform, for every dollar of common equity added to the capital structure, it cost ratepayers 15.2 cents or about 3.5x the Company's cost of debt of

[10] ABATE Witness C. Walters – CE Electric Case No. U-21224- Direct testimony, p 69.
[11] Cost of LT-Debt for Historical Year ended December 31, 2023. Exhibit No. A-4 (HLR-24), Sched. D-2.

4.0 cents. Post tax reform, it cost ratepayers 12.5 cents for every dollar added of common equity, or over 3.0x the cost of debt. Therefore, equity is clearly costlier to ratepayers than debt. In these times of economic uncertainty, it is even more important to establish a proper equity to debt ratio to maintain reasonable costs to ratepayers. Staff's 50% equity recommendation establishes that sensible objective of equilibrium and lessens the cost burden on stressed ratepayers.

Q. Please summarize the recommended cost rates of Staff and the Company.

A. The chart below outlines the cost rates recommended by the Company and Staff:

Chart 2.

| Components | Company | Staff |
|---|---|---|
| Long-Term Debt | 4.35 % | 4.33 % |
| Preferred Stock | 4.50% | 4.50% |
| Common Equity | 10.25 % | 9.75% |
| Short-Term Debt | 4.52% | 4.52% |
| Deferred Federal Income Tax | 0.00% | 0.00% |
| Job Development Investment Tax Credits | Blended cost | Blended cost |

Based on Chart 2, Staff disagrees with the Company's cost rates for LT-Debt and common equity. Staff agrees with the other cost rates.

Q. Please explain the difference in Staff's and the Company's LT-debt cost rate.

A. Staff and the Company's LT-debt cost rate difference stems primarily from the cost rates estimated to Consumers forecasted new debt issuances in 2025 and 2026. The Company projected May and August 2025 debt issuances of $1.0 billion, and May and August 2026 debt issuances of $925 million. The Company provided a cost rate for the May and August 2025 debt issuances at 5.66% and for the May and August 2026 debt issuance at a cost rate of 5.67%. I estimated a

lower cost rate of 5.58% for the 2025 debt issuances and 5.11% for the 2026 debt issuances. I used 30-year bond yield forecasts from IHS Markit, and the average 30-year bond yield forecasts provided by Econforecasting.com. Those changes, which include Staff agreeing to the other LT-Debt cost rates estimated by the Company, provide for a Staff recommended overall LT-Debt cost rate of 4.33%. This cost rate is two basis points less than the Company's cost rate of 4.35%. My LT-Debt analysis is shown on Staff Exhibit No. S-4, Schedule D-2.

Q. Please explain the difference in Staff's and the Company's return on equity.

A. Staff provides a thorough discussion of its return on equity analysis and recommendation and the difference between Staff's and the Company's cost of equity determination in the return on equity analysis below.

Q. Does Staff have a view on the Company's cash on hand recommendation?

A. Yes. Staff asked the Company in an audit request about the difference between cash on hand and short-term debt, and the purpose of each provision. Staff has provided the Company's response as Exhibit S-4, Schedule D-6, p 2 of 2. The Company responded that cash on hand is used for general corporate purposes and working capital, which they state is required along with the use of ST-debt. The Company notes the similarities between the two except for their accounting treatment. However, Staff believes the Company's excessive ST-debt facilities, at well over $1.0 billion, is inefficiently used and costly to ratepayers. Additionally, the Company's 1% of gas revenue cash on hand request also increases the Company's revenue requirement. Therefore, Consumers' over-abundant ST-debt facilities and the 1% cash on hand request is a combination that is very costly to

ratepayers and should be modified. Staff's many audit requests to Consumers revealed that the Company has not used several of its revolver facilities in years, yet ratepayers are paying full freight for the Company to have them available. Staff suggests the Company reduce its substantial revolvers or reduce it cash on hand request from 1% of gas revenues to something less extensive to provide a more efficient use of both facilities and to lessen the cost burden on ratepayers.

## Part II. Return on Equity Analysis

Q. In establishing a legal base for Staff's return on equity analysis in this rate case, what considerations did Staff take into account?

A. Traditionally, when considering a return on equity recommendation for a utility company, Staff considers the legal guidelines from the landmark rulings of Hope and Bluefield. Those cases described various methods such as the "Attraction of Capital" and the "Returns Commensurate with Those on Investments in Enterprises of Comparable Risks" that the Supreme Court found to be lawful and prudent. In *Bluefield Water Works and Improvement Co. vs. Public Service Commission*, 262 U.S. 679, 692-693 (1923) case, the Court stated:

> "A public utility is entitled to such rates as will permit it to earn a return on the value of the property which it employs for the convenience of the public equal to that generally being made at the same time and in the same part of the country on investments in other business undertakings which are attended by corresponding risks and uncertainties; but has no constitutional right to profits such as are realized or anticipated in highly profitable enterprises or speculative ventures."

Furthermore, in 1944 in *Federal Power Commission vs. Hope Natural Gas Company*, 320 U.S. 591, 603 (1944) case, the Court stated:

"From the investor or company point of view, it is important that there be enough revenue not only for operating expenses but also for the capital costs of the business. These include service on the debt and dividends on the stock. By that standard the return to the equity owner should be commensurate with returns on investment in other enterprises having corresponding risks. That return, moreover, should be sufficient to assure confidence in the financial integrity of the enterprise, so as to maintain its credit and to attract capital."

The Supreme Court established an "end result" doctrine which surmised that how a capital structure and rate of return was determined was not so important as long as the end result was appropriate and reasonable for the case at hand. No one methodology provides an exact measure of a fair rate of return on equity, but some methods provide good estimates. The Discounted Cash Flow method (DCF) and the Capital Asset Pricing Model (CAPM) are the primary models most utility financial analysts use in rate cases to determine a fair and reasonable cost of equity for regulated utility companies. I employed those same methods in this rate case along with a bond yield + risk premium method and a comparison of recent gas ROE determinations from other state jurisdictions.

Q. Please explain the development of the gas utility proxy group you used in your cost of equity analysis for Consumers Energy's Gas Division.

A. I used all the companies identified in Consumers Energy's proxy group with some additions. I primarily looked at six criteria in selecting a proxy group of comparable utility companies used in my ROE analysis: 1) each utility had to have net plant greater than $3.0 billion but less than $26.0 billion to better

compare in size and footprint to Consumers Energy's gas division[12]; 2) each company had to derive no less than approximately 50% or more of its revenues from regulated natural gas service; 3) each utility had to have an investment grade rating within three-four notches from that of Consumers Energy, mainly from the two primary rating agencies, S&P and Moody's; 4) each company had to currently be paying dividends to shareholders; 5) each utility had to be followed by 2 or more International Business Estimating System (I/B/E/S) analysts; and 6) each company was not currently involved in a merger or major corporate buyout or sell-off that could significantly impact the company's stock price.. With this selection criterion, I came up with a list of eight gas utility companies, which are outlined in Exhibit S-4, Schedule D-5, page 2 of 14.

Q. How does your proxy group compare to the Company's proxy group?

A. The Company's proxy group consists of 6 utilities, all of which are part of my proxy group, but my proxy group includes the additions of DTE Energy and New Jersey Resources. I included DTE Energy because they are the primary comparison utility to CMS Energy/Consumers Energy in the state of Michigan. I included New Jersey Resources because even though the company is rated by Moody's and Fitch and not S&P, that small factor did not affect my inclusion of the company into my proxy group. Thus, with the noted additions to the Company's proxy group, I developed an eight-company utility proxy group.

[12] The lone exception is DTE Energy, CMS Energy's/Consumers Energy's primary competitor and comparable holding company in the State of Michigan.

Q. Please provide a brief description of Staff's Exhibit S-4, Schedule D-5, pages 2 through 4.

A. Exhibit S-4, Schedule D-5, page 2 provides some business statistics on Consumers Energy and the proxy group utilities used in this rate case. Columns (e) and (f) describe the credit ratings assigned to each utility by the credit rating agencies S&P and Moody's. The proxy group's average S&P credit rating is (A-/BBB+), which is approximately one or two notches below Consumers credit rating of (A). Moody's average credit rating for the group is (A3/Baa1), which is two notches below Consumers credit rating of (A1). Thus, Consumers Energy Gas is considered a better credit risk, i.e., safer company than the proxy group. Column (g) describes the dividend payout ratio of each utility. Consumers Energy dividends out to its parent company 80% of its net income compared to the proxy group's 60% payout ratio. Columns (i) describes the number of analysts covering the Company with respect to the I/B/E/S, which is a source widely used in ROE analyses across the country. Column (j) highlights the latest allowed return on equity for each gas utility or gas utility subsidiary in the proxy group. Columns (k) and (L) highlights the authorized equity layer and the date of the order according to S&P Global Market Intelligence. The average equity layer for the gas proxy group is 53.62% and the average authorized ROE is 9.61%. The ROE is considerably less than Consumers Energy's current 9.90% authorized ROE and substantially less than Staff's 9.75% ROE recommendation.

Exhibit S-4, Schedule D-5, page 4 describes the realized return on common equity for the proxy group and Consumers Energy from 2020 through

2024. The average return on equity over the 5-year period for the proxy group was 8.94% and for Consumers was 10.10%. Thus, on average, the proxy group's financial return did not reach its average authorized ROE of 9.61%. However, Consumers Energy's Gas division has earned over its authorized ROE of 9.90%, including substantially over-earning the past three out of five years. That reality does not suggest that the Company's ROE should be increased to 10.25% but modestly lowered to Staff's favorable 9.75% ROE.

**Discounted Cash Flow Model (DCF) Analysis**

Q. Please provide a brief explanation of the DCF and how it is used in this analysis**.**

A. The DCF method has been a widely used approach for estimating equity investors return demand since the 1960s. It was introduced after the 1929 stock market crash by I. Fisher in 1930 and expanded upon by J.B. Williams in 1938 before being elaborated on by M.J. Gordon and E. Shapiro. The approach derives its basis by surmising how investors evaluate stocks for potential investment. The formula assesses that investors value securities by evaluating the present value of expected future cash flows attributed to those securities. The model suggests that expected future cash flows include dividends, the projected market value of the security at liquidation, and the discount or capitalization rate investors apply to the future cash flows. The model evaluates the current price of a stock with the assumption that the growth of the stock will be constant throughout its life and that its growth will be less than the cost of its equity. The formula is

$P = D_1 / k – g$ where:

P = Price per share

$D_1$ = Dividend per Share Expected

k = Cost of Equity

g = Expected Growth Rate

Rearranging the above formula into the basic DCF formula is the mathematical equation that states that the cost of equity is equal to the security's dividend yield plus a projected future growth rate of the stock. The basic DCF formula is

$K = D_1/P + g$ where:

K= Cost of Equity

$D_1$ = Expected Quarterly Dividend Rate Annualized

P = Market Price of the Security

*($D_1/P$ = Dividend Yield)*

g = Expected Growth Rate

Q. Please explain the computation of your DCF analysis.

A. I outline my DCF analysis on Exhibit S-4, Schedule D-5, page 5 of 14. I used January 1, 2025, through March 1, 2025, closing stock prices and averaged them for the proxy group. I then annualized current quarterly paid dividends to calculate dividend yields for the proxy group. The current annual dividend is indicated in column (i). The dividend yield was modified by the semi-annual compounding method based on the formula $DCF = (D_1/P) *[1 + 0.5g] + g$. The semi-annual compounding model is the preferred model to use when performing a DCF analysis on a group of comparison companies.[13] This is also the preferred

[13] Parcell, D.C. (1997) *The Cost of Capital – A Practitioner's Guide*, 1997 Edition, Chapter 8, pages 10-13.

method used by Federal Energy Regulatory Commission (FERC). The ratemaking dividend yield is highlighted in column (j).

The bottom section of the exhibit highlights the projected growth rates in the proxy group's earnings for a 3-5-year period. The growth rate in earnings used in my DCF analysis were gathered from widely used and well-known sources such as Zacks and Value Line. The growth rate estimates are averaged together and ranged from a low rate of 3.99% to a high of 7.75%.

Q. Staff, Consumers Energy, and most other intervenors have traditionally used the 3–5-year growth rate projection data from Yahoo Finance. Why have you not included that data in your analysis in this rate case?

A. Yahoo Finance appears to have discontinued or temporarily halted their 3-5-year growth rate forecasts. On their website, Yahoo Finance only offers a 1-year growth rate forecast and not their 3-5-year growth data projections as they have in the past. Staff emailed Yahoo Finance and asked why they do not show their 3-5-year growth rate data anymore and the website has not offered a response at this time. Staff does not know if the change is temporary or permanent.

Q. With the data available, what DCF cost of equity estimate did you arrive at?

A. I arrived at an average DCF cost of equity estimate of 9.40%. The DCF cost of equity was determined using the constant model, which adds the average dividend yield to the expected growth rate denoted by lines [A] +[B].

Q. Did Consumers Energy provide a DCF cost of equity estimate?

A. Yes. Company witness Ann Bulkley provides a mean average DCF cost of equity estimate of 10.05% and a median average DCF cost of equity estimate of 10.02%,

using the Company's six utility proxy group. The Company provided three separate analyses using the same growth rates from Value Line, Yahoo! Finance and Zacks with the change being in the length of the stock price analysis, either 30-day, 90-day or 180-day.

Q. Do you agree with the Company's DCF analyses and ROE estimate?

A. For the most part, yes. The Company's approximate 10.0% average ROE estimate using its three different analyses is not out of bounds and the growth rate data appears reasonable. One issue is that the Company does not provide a date when its growth rate data was retrieved, so Staff is unsure if the data used in the analysis is timely or stale. Nonetheless, the results appear reasonable.

Q. Should the inclusion of flotation costs be considered in any of the cost of equity models for the Company?

A. No. Though the Company has not expressly requested the inclusion of flotation costs as a basis point increase to any of its cost of equity models in this case, they do devote approximately four pages of testimony to its rationale for inclusion (Direct Testimony of Ann E. Bulkley p. 34-37) and show a flotation cost adjustment in the Company's DCF analysis on Exhibit No. A-14, Schedule D-5, p 26 of 29. Nonetheless, flotation cost enhancement to any of the Company's ROE estimates should be rejected. Consumers Energy, as a stand-alone entity, issues and procures its own long-term and short-term debt. In that vein, the Company is allowed to recover all the costs and fees associated with those issuances and includes those costs in its overall cost of capital determination. However, it would be improper to include flotation costs in the Company's cost of equity

portion of its overall cost of capital because Consumers Energy, as a subsidiary of its parent company CMS Energy, does not issue its own stock and thus, does not incur issuance/flotation costs.

## Capital Asset Pricing Model (CAPM) Analysis

Q. Please discuss Staff's Historical CAPM method.

A. The CAPM model was derived from the study and analysis of economists Sharpe, Lintner and Treynor and in its simplified form is expressed by the equation:

$$E(R) = R_f + \beta*[E(Rm) - R_f]$$

Where: $E(R)$ = Expected rate of return on a risky security
$R_f$ = Risk-free rate of return
$E(Rm)$ = Expected market rate of return
$\beta$ = The systematic risk or beta of a security

In theory the CAPM model differentiates between two types of risk, diversifiable and non-diversifiable risk. The theory suggests that an investor's required return is based on the investor's exposure to risk that is systemic in the market, i.e. non-diversifiable risk. Risk that is unique to a particular security is called firm specific risk. One of CAPM's primary assumptions is that investors are fully invested in the market, i.e. invested in a portfolio of stocks, and thus eliminate or substantially reduce firm specific risk. Hence, the model infers that investors risk exposure is primarily composed of market risk and since this is risk that cannot be diversified away, it should be the basis for investor compensation. The beta coefficient measures the volatility of a security's stock price as it relates to changes or movements in the market and extends as the market risk component.

Q. What market risk premium estimate is used in your CAPM model?

A. I used a few market risk premiums in my analysis, a historical risk premium and two projected market risk premiums provided by an industry expert. I will discuss the projected risk premiums later in my testimony. In evaluating the historical risk premium, I reviewed the Kroll (formerly Ibbotson Associates) study entitled Stocks, Bonds, Bills and Inflation: The 2023 Yearbook. The study provides historical values for market return indices used in the estimation of risk premiums and common equity costs. The study was formally updated annually.[14] Taking the difference between the average stock return and government bond return over the period indicated a 6.94% market risk premium (MRP). The historical MRP derivation is shown on Exhibit S-4, Schedule D-5, page 6 of 14.

Q. What risk free rate ($R_f$) did you use in your CAPM analysis?

A. Government securities are commonly considered to be risk-free. The risk-free rate used in my CAPM analysis is the yield associated with a long-term U.S. government Treasury bond. I reviewed S&P Global Market Base Forecast for 30-year Treasury bond yield forecasts for 2025 and 2026, and average (Dec 31 – Dec 31) forecasts over the same period from Econforecasting.com. I used 30% weight to the 2025 estimate and 70% weight to the 2026 estimate to establish an average risk-free rate of 4.25%.

Q. What beta did you use in your analysis and its source?

[14] Kroll announced in January 2024 that future editions of the SBBI Yearbook would no longer be available and thus, no 2024 edition of the SBBI Yearbook would be offered. Going forward, Staff will use a combination of the Kroll SBBI yearbook for data up to 2022, data from Damodaran Online (NYU) website for future S&P 500 market data, and long-term government bond data from the Federal Reserve.

A. I used the gas group's beta derived from Value Line. By definition, the market beta is 1. The Value Line beta is a forward-looking beta, which measures a 60-month average raw beta on a weekly basis and adjusts that raw beta by a convergence factor towards the market beta 1. Stocks with betas less than 1 are considered less volatile and thus less risky than stocks with betas greater than 1.

Q. What cost of equity estimate did you arrive at using the historical CAPM method?

A. Combining the average risk-free rate of 4.25% with the calculated historical risk premium of 6.94% and the gas group's beta in the CAPM formula [Rf + β*(MRP)], I computed an average CAPM cost of equity of 10.63% for the historical period.

Q. Did you also provide a Projected CAPM analysis?

A. Yes. To account for the forward-looking nature of the CAPM, primarily with respect to market return and equity risk premium derivation, I also conducted a projected CAPM analysis using forward-looking market risk premium estimates provided by Professor Aswath Damodaran in his Damodaran Online Finance website. Damodaran On-line Home Page (nyu.edu).

Q. Please explain your Projected CAPM analysis.

A. Professor Damodaran provides a projected 5-year analysis of the S&P 500, known as the trailing 12-month cash yield market risk premium analysis, as noted in his Implied Risk Premium Calculator. The professor computed an implied risk premium of 4.35%. The professor also computed a 10-year cash-yield

smoothed[15] market risk premium analysis of 6.18%. I used both the 4.35% and 6.18% MRPs in my projected CAPM analysis.

Q. What projected CAPM cost of equity estimates did you arrive at?

A. Combining the average risk-free rate of 4.25% with the projected risk premia of 4.35% and 6.18% and the gas group's betas, I computed two CAPM ROE estimates of 8.25% and 9.93%.

Q. Are Staff's projected CAPM ROE estimates reasonable in this case?

A. Yes. Professor Damodaran's market risk premium data and analysis is thoroughly explained on his website and the results from his data appear to be neither too insufficient as to be deemed unreasonable, nor too high to be deemed unacceptable outliers. The data provides reasonable CAPM ROE results.

Q. Did the Company provide a CAPM analysis and cost of equity estimate?

A. Yes. The Company provided two analyses, a projected CAPM analysis that used Value Line and Bloomberg betas and a projected CAPM analysis that used average historical Value Line betas. The Company also conducted a projected empirical CAPM or ECAPM analysis using the same Value Line and Bloomberg beta data. In total, the Company provided 18 ROE estimates.

Q. Please explain how the Company derived its CAPM results.

A. The Company provided a traditional CAPM analysis that used Bloomberg and Value Line betas, a current, near-term and long-term 30-year risk-free rate, and a

[15] Investopedia.com definition: Data smoothing can be used to help predict trends, such as those found in securities prices, as well as in economic analysis. Data smoothing is intended to ignore one-time outliers and take into account the effects of seasonality. Smoothed data is generally preferred by economists because it better identifies changes in trends compared to unsmoothed data, which may appear more erratic and create false signals. (referenced – 4/1/2025)

projected market risk premium. Additionally, the Company also provided the same information but used a long-term historical average Value Line beta. The Company's projected CAPM analysis produced nine ROE estimates with a low of 10.06% to a high of 11.07%.

Consumers' ECAPM approach modifies the traditional CAPM approach with the inclusion of an adjustment that purports to better align low beta companies with observed returns in the market.[16] The Company applies a 75% weighting to the CAPM equation with the beta factor incorporated into the market risk premium data and a 25% weighting without the beta incorporated into the market risk premium. The equation is $ke = rf + 0.75\ \beta(rm - rf) + 0.25(rm - rf)$. The Company calculated nine ECAPM ROE estimates with a low of 10.56% to a high of 11.32%.

Q. Do you agree with the Company's Projected CAPM and ECAPM analyses?

A. Not entirely. I disagree with the ECAPM in general and will explain my disagreement later in testimony. The Company uses a projected S&P 500 market return of 12.04%, which appears on the high-end of reasonableness. The Company's risk-free rates range from 4.02%, 4.07% to 4.30%. Subtracting the risk-free rate from the 12.04% market return, provides a market risk premium estimate of 8.02%, 7.97% and 7.74% respectively. These market risk premium results are substantially higher than the historical market risk premium of around 7.0% and substantially higher than Professor Damodaran's projected estimates of

[16] *Id.* at 28.

4.2-6.2%. The Company's estimates produce inflated CAPM ROE results, with an average ROE result of 10.57%. The Commission should give limited weight to the inflated MRP used in the Company's CAPM analyses and the inflated ROE estimates.

Q. Are there aspects of the Company's CAPM analysis you agree with?

A. Yes. Staff agrees with the Company's use of the Value Line long-term beta in its CAPM analysis. The Company developed its historical long-term beta by averaging the Value Line betas annually from year-end 2013 to year-end 2023. This smoothed the current beta values that consider the unreasonably high beta period during the Covid years of 2020 – 2021. The smoothing produces more reasonable average betas of 0.62 – 0.85 than the current high Value Line betas values 0.85 – 1.00. Regulated utilities have historically been well below the overall market beta of 1.00, so current beta values are unreasonably high. If Staff used the Company's historical Value Line betas in its historical CAPM analysis, the average ROE estimate would have been approximately 9.60% instead of the high 10.63%.

Q. Please explain your disagreement with the Company's ECAPM approach.

A. I disagree with the ECAPM approach in general because the ECAPM was established based on the results of the CAPM using raw betas and short-term debt metrics. However, the Company's ECAPM analysis does not use raw betas nor short-term debt metrics, the Company's analysis uses Value Line and Bloomberg adjusted betas and long-term debt metrics. This change in inputs renders the need for the ECAPM adjustment unnecessary. As Staff noted earlier in its testimony,

Value Line and Bloomberg modifies its beta using the "Blume" adjustment that adjusts beta to account for the tendency to converge toward the market beta 1.00. The two entities adjust its beta by using the equation $\beta_{adjusted} = 0.34 + 0.66\ \beta_{raw}$. To illustrate this difference in a CAPM analysis using modified and unmodified betas, Staff provides a sample analysis below.

Example 1.

| | |
|---|---|
| Value Line Beta ($\beta_{adjusted}$) = | 0.70 |
| $\beta_{adjusted} = 0.34 + 0.66\ \beta_{raw}$ | |
| $0.66\ \beta_{raw} = \beta_{adjusted} - 0.34$ | |
| $\beta_{raw} = 0.36 / 0.66$ = | 0.54 |
| | |
| Sample Risk-free rate (Rf) = | 2.5% |
| Sample Market Risk Premium (MRP) | 7.0% |
| | |
| CAPM using adjusted Value Line beta | |
| $K = Rf + \beta_{adjusted}$ x MRP | |
| K = 2.5% + (0.70)*(7.0%) = | **7.40%** |
| | |
| ECAPM using raw beta where X = 0.34 | |
| $K = Rf + X$ x MRP + $(1 - X)(\beta_{raw}$ x MRP) | |
| K = 2.5% + 0.34*(7.0%) + (1- 0.34)*(0.54 x 7.0%) | |
| K = 2.5% + 2.4% + 2.5% = | **7.40%** |

From the equation above, you can see that using adjusted betas in the regular CAPM equation produces the same results as using raw betas in the ECAPM analysis. Therefore, using adjusted betas in the ECAPM analysis is tantamount to double counting the beta and improperly inflating the ROE estimate. This strengthens Staff's contention that Value Line and Bloomberg betas are improper for use in the ECAPM analysis. Thus, Staff's ratemaking CAPM analysis, with its use of long-term risk-free rates and adjusted betas, renders the ECAPM

adjustment unnecessary. The Commission has not considered the merits of the ECAPM approach nor its ROE estimate in the past and should not consider any merit to the ECAPM approach in this case as well.

**Bond Yield + Risk Premium Analysis**

Q. Please outline your bond yield + risk premium analysis.

A. My bond yield + risk premium approach incorporates the spread from historical gas utility realized stock returns and historical composite utility bond yields and adds this spread to a projected A-rated long-term utility bond yield to obtain an investor's current reasonable required rate of return. I also incorporate a historical Treasury Bond analysis to estimate an additional bond yield + risk premium ROE estimate.

Q. Please explain the derivation of your bond yield + risk premium approach.

A. I reviewed the Natural Gas Utility Realized Market Return Average from 1954 through 2024 compared with the A-Rated Public Utility Bond Yield Average over the same period. Mergent Public Utility Manual & Bond Record provided complete market return and bond yield data until 2000. To obtain utility market return data for 2001 to 2024, I used a combination of data from the Dow Jones Utilities index, data from the S&P 500 Utilities Corporate Bond Index, bond data from Value Line - Select Yields, and a 2024 A-rated utility bond estimate from the Federal Reserve Economic Data website (FRED). The information is shown on Exhibit S-4, Schedule D-5, page 10 of 14.

The average gas utility market return over that period was 10.94% and the average A-rated composite utility bond yield was 7.14% over the same period. Subtracting the bond yield from the market return yielded an historical spread of 3.80%. In addition, a Treasury Bond yield of 5.73% was derived over the same historical period to produce an historical Treasury Bond spread of 5.21% as shown on Exhibit S-4, Schedule D-5, page 12 of 14.

Q. What bond data did you use in your risk premium calculation?

A. I use projected A-rated utility bond yield data from S&P. The average yield for a projected 2025-2026 A-rated utility bond is 5.76%.[17] Adding the projected bond yield to the historical market risk premium of 3.80% produces an ROE estimate of 9.56%. Additionally, when adding the historical Treasury Bond spread of 5.21% to the projected 30-year T-bond yield of 4.25%, produces an ROE estimate of 9.46%. This information is shown on Exhibit S-4, Schedule D-5, page 12 of 14.

Q. Did the Company provide a Bond Yield + Risk Premium (BYRP) analysis and ROE estimate?

A. Yes. The Company provided a BYRP analysis that produced an average ROE estimate of 10.25%.

Q. Do you agree with the Company's BYRP analysis and ROE result?

A. Not entirely. The Company methodology for its BYRP analysis is somewhat complicated and circular. Consumers uses the average authorized natural gas ROEs from 1980 – the 3rd quarter 2024 as the overall market return, compared

[17] Cost of Funds – To Public Utilities: S&P Global Market Intelligence – US Economic Outlook Tables p.52: Yr. 2025 = 5.77%, Yr. 2026 = 5.75%: Avg = 5.76% (Feb. 2025)

with the 30-year U.S. Treasury bond during the same period to develop a risk premium over that period. The Company notes that there is a strong negative relationship between risk premia and interest rates, i.e. as interest rates go up, risk premia go down and vice versa. The Company then conducts a regression analysis to determine if indeed historical interest rates and risk premia are inversely correlated. However, Staff's concern is that using historical authorized ROEs as a market return source in a cost of equity model is somewhat circular as ROEs consider numerous factors when rendered by that state's commission, not just interest rates prevalent at the time. Staff believes that using state authorized ROEs in a comparable fashion with the ROE results from your model analysis is reasonable. However, using authorized ROEs as an input into the BYRP model is somewhat circular and the Commission should give limited weight to the Company's bond yield + risk premium analysis.

Q. Did Staff review any other study in its return on equity analysis?

A. Yes. As previously referenced, I reviewed the authorized rate of return decisions for gas utilities rendered by other state commissions across the country for the years 2022, 2023 and 2024. The average authorized ROE decision for 2022 was 9.53%, 9.64% for 2023 and 9.72% for 2024. That equates to a 3-year average of 9.63%, which is well below Staff's ROE recommendation of 9.75% in this case. The data was derived from the Regulatory Research Associates (RRA) database. The information is noted on Exhibit S-4, Schedule D-5, page 13 of 14.

Q. Did the Company opine on the merits of the RRA database?

A. Not directly in this case but it has in past rate cases. The Company extends that the RRA database is incomplete and does not represent the full spectrum of ROEs that should be considered in an analysis. Staff asked in an audit request, in case No. U-21148, whether the Company had separate ROE authorizations for a portion of its gas assets. The Company responded yes. [18] Staff included the Company's audit response as an exhibit (Exhibit S-4, Schedule D-6, p 1 of 32). Staff notes that the Company's complaints regarding the apparent limitations of the RRA database should be dismissed. Staff's use of the RRA database as a comparable basis for the Company's ROE recommendation is both reasonable and appropriate and should be given full weight by the Commission.

Q. Based on your ROE analysis, what is Staff's recommended cost of common equity for Consumers Energy's gas division in this rate case?

A. Below is a summary of Staff's cost of equity estimates from its various cost of equity calculations and Staff's recommended ROE:

| ROE Analysis | ROE |
|---|---|
| Traditional DCF: | 9.40% |
| Historical CAPM: | 10.63% |
| Projected CAPM – Damodaran – Trailing 12-mnth cash yield ERP: | 8.25% |
| Projected CAPM – Damodaran – 10-yr cash yield (smoothed) ERP: | 9.93% |
| Bond Yield + Risk Premium – Projected Aa-Rated Utility Bond: | 9.56% |
| Historical Treasury Bond + Projected LT- Treasury. Bond: | 9.46% |
| Avg. Gas Utility Authorized ROE Decisions Across the U.S -2024: | 9.72% |
| Avg. Gas Utility Authorized ROE Decisions Across the U.S -2023: | 9.64% |
| Avg. Gas Utility Authorized ROE Decisions Across the U.S - 2022: | 9.53% |
| Recommended Cost of Equity Range: | 9.25% - 10.25% |
| ROE recommended and used in Overall Cost of Capital | 9.75% |

[18] Case No. U-21148, Staff Exhibit S-4, Schedule D-6, page 1 of 2.

Based on the results above, it is Staff's judgment that a cost of equity recommendation for Consumers Energy's gas division falls within the range of 9.25% - 10.25%, as highlighted in Exhibit S-4, Schedule D-5, page 14 of 14. Considering the Company's current authorized ROE of 9.90% and the Commission's request that ROE recommendations reflect prudence, it is Staff's judgement that its ROE recommendation of 9.75% is very fair and reasonable.

Q. Does Staff's ROE align with Consumers Energy's recommendation in this case?

A. No. Company witness Bulkley supports Consumers Energy's ROE recommendation of 10.25%. The Commission should reject this recommendation for several reasons. First, the ROE request is 35 basis points higher than the Company's currently authorized 9.90% ROE, which does not coincide with the Commission's request for prudence. Second, the request also does not coincide with Consumers Energy's solid credit rating and the Commission's approval of the Company's gas infrastructure improvement programs along with surcharge mechanisms to pay for those programs. This treatment all but ensures recovery of costs associated with those programs and reduce the Company's overall business and financial risk. In addition, the Company's practice of filing a new rate case no more than 12 months after its prior rate case, borders on a 100% risk-free investment for the Company. This tremendous risk reduction calls for an ROE dramatically less than the Company's 10.25% request. Staff's suitable 9.75% ROE properly balances the needs of the Company along with a reasonable level of fairness to the Company's ratepayers.

**Capital Structure and ROE Summary**

Q. Please summarize your capital structure and ROE recommendation

A. My recommendations are as follows:

1. Staff recommends a capital structure with a 50.0% equity layer.

2. Staff recommends an ROE of 9.75%.

3. Staff recommends a proxy group consisting of eight utilities that fit within Staff's six-metric selection criterion.

4. Staff recommends the use of three ROE models, the DCF model, the CAPM model and the Risk Premium + Bond Yield model. Staff also recommends a review of nationally authorized ROEs to help assess the Company's recommended ROE.

5. Staff notes that the Company's credit rating is stable, and the Company has programs in place that provide revenue stability and reduced risk.

6. Staff recommends the Commission reject Consumers Energy's impractical and unreasonable ROE recommendation of 10.25%.

Q. Does this conclude your testimony?

A. Yes.

MS. STIRLING: Staff calls to be filed the qualifications and direct testimony of Kevin Krause that consists of a cover sheet and eight pages of questions and answers. Mr. Krause sponsored two exhibits associated with his direct testimony. These exhibits have been marked Exhibit S-6 Schedule F-1.1, and Exhibit S-6 Schedule F-1.1b.

Mr. Krause also sponsored rebuttal testimony consisting of a cover page and five pages of questions and answers. Mr. Krause has one exhibit associated with his rebuttal testimony, and this exhibit has been marked Exhibit S-24.

The Staff moves to bind into the record the qualifications and direct, as well as the rebuttal testimony, and exhibits of Kevin Krause.

JUDGE VARCHETTI: Any objections regarding the direct or rebuttal testimony of Mr. Krause or any of the associated exhibits?

Hearing none, then, the testimony is bound into the record, and the exhibits are admitted.

(Direct Testimony, Qualifications, and Rebuttal Testimony bound in)

**S T A T E  O F  M I C H I G A N**

**BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION**

*** * * ***

| | | |
|---|---|---|
| **In the matter on the Application of CONSUMERS ENERGY COMPANY for authority to increase its rates for the distribution of natural gas and for other relief.** | **)** | **Case No. U-21806** |

# QUALIFICATIONS AND DIRECT TESTIMONY OF

# KEVIN S. KRAUSE

# MICHIGAN PUBLIC SERVICE COMMISSION

**April 23, 2025**

**QUALIFICATIONS OF KEVIN S. KRAUSE**
CASE NUMBER U-21806
PART I

Q. Please state your name and business address.

A. My name is Kevin S. Krause, and my business address is 7109 W. Saginaw Highway, Lansing, MI 48917.

Q. By whom are you employed and in what capacity?

A. I am employed by the Michigan Public Service Commission (Commission or MPSC) as a Gas Cost of Service Specialist within the Regulated Energy Division, Rates and Tariff Section.

Q. How long have you been employed by the MPSC and what are your duties?

A. I have been employed by the MPSC since February of 2009. I was assigned to the Revenue Requirements Section to analyze and make recommendations regarding Rate Base, Net Operating Income, and Depreciation issues in general rate cases and depreciation rate cases. In August of 2012, I was transferred to the Renewable Energy Section. In November of 2016, I was transferred to the Rates and Tariff Section.

Q. Please describe your educational background.

A. I graduated from the University of Michigan in 1990 with a Bachelor of Science degree in Nuclear Engineering. I received a Masters of Nuclear Engineering from the same school in 1991. I also received a Masters in Business Administration from Michigan State University in 1999. I have taken classes as part of the Certified Public Accountant preparation program at Lansing Community College. I also attended the Institute of Public Utilities - Regulatory Studies Program at Michigan State University. In the fall of 2010, I completed the Depreciation Basics Training conducted by the Society of Depreciation Professionals (SDP).

Q. Please describe your professional background.



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**QUALIFICATIONS OF KEVIN S. KRAUSE**
CASE NUMBER U-21806
PART I

A. From 1992 to 1997, I worked as a Nuclear Engineer for B & W Fuel Company in Lynchburg, Virginia. My duties there included performing fuel cycle analysis and related calculations. In 1998, I was a procurement intern with Public Service Electric and Gas Company of Newark, New Jersey. From 2002 to 2010, I was an adjunct professor of Mathematics at Lansing Community College.

Q. Have you previously presented testimony or helped develop the Commission Staff's (Staff) position in cases before the MPSC?

A. Yes, I have filed or developed Staff's position in the following cases with area of testimony specified:

U-15768: Detroit Edison Electric - AFUDC

U-15935: Alpena Power - Operations and Maintenance (O&M) Expense

U-15985: Michigan Consolidated Gas Case - Revenue Deficiency

U-15986: Consumers Energy Gas Case - Rate Base

U-16180: Indiana Michigan Electric Case - Rate Base

U-16166: Upper Peninsula Power Company – O&M Expense

U-16169: SEMCO Energy Gas Company – O&M Expense

U-16417: Upper Peninsula Power Company Electric Case - Revenue Deficiency

U-16475: Northern States Power Company Electric Case - Revenue Deficiency

U-16794: Consumers Energy Electric Case - Rate Base

U-16801: Indiana Michigan Electric Case - Rate Base

U-16855: Consumers Energy Gas Case - Rate Base

U-17026: Indiana Michigan Certificate of Necessity – Accounting

U-17303: Indiana Michigan Renewable Energy Plan



VERITEXT LEGAL SOLUTIONS

**QUALIFICATIONS OF KEVIN S. KRAUSE**
CASE NUMBER U-21806
PART I

U-17321: Consumers Energy 2012 Renewable Reconciliation

U-17323: Indiana Michigan 2012 Renewable Reconciliation

U-17429: Consumers Energy Certificate of Necessity – Accounting

U-17631: Consumers Energy 2013 Renewable Reconciliation

U-17632: DTE Electric 2013 Renewable Reconciliation - Rebuttal

U-17633: Indiana Michigan 2013 Renewable Reconciliation

U-17767: DTE Electric Rate Case – Certain Nuclear Expenses

U-17803: Consumers Energy 2014 Renewable Reconciliation

U-18014: DTE Electric Rate Case – Renewable Expenses

U-18090: Consumers Energy – Avoided Cost

U-18091: DTE Electric – Avoided Cost

U-18322: Consumers Energy – Standby Rates – Rebuttal

U-18255: DTE Electric – Standby Rates – Rebuttal

U-18259: Presque Isle Gas – Cost of Service and Rate Design

U-18424: Consumers Energy Gas Rate Case – Other Gas Revenue

U-18999: DTE Gas Rate Case – Other Gas Revenue and Rate Design

U-20106: DTE Gas – Credit A

U-20115: SEMCO Energy Gas Company – Credit A

U-20182: SEMCO Energy Gas Company – Credit B

U-20134: Consumers Energy Rate Case – Standby and Electric Vehicle Rates

U-20162: DTE Electric Rate Case – DG tariff, Standby and Electric Vehicle Rates

U-20276: UPPCO Electric Rate Case – Rate Design

U-20479: SEMCO Gas Rate Case – Cost of Service

**QUALIFICATIONS OF KEVIN S. KRAUSE**
CASE NUMBER U-21806
PART I

U-20359: Indiana Michigan Rate Case – Demand Charge pilot and DG tariff rebuttal

U-20561: DTE Electric - DG tariff rebuttal

U-20642: DTE Gas Rate Case – Cost of Service

U-20650: Consumers Energy Gas Rate Case – Cost of Service

U-20697: Consumers Energy Electric Rate Case - DG Tariff

U-20940: DTE Gas Rate Case – Cost of Service

U-20718: MGU Gas Rate Case – Cost of Service

U-21090: Consumers Energy Integrated Resource Plan

U-21148: Consumers Energy Gas Rate Case – Cost of Service

U-20836: DTE Electric – DG tariff and Electric Vehicles

U-21226: NSP Gas Rate Case – Cost of Service

U-21308: Consumers Energy Gas Rate Case – Cost of Service

U-21366: MGU Gas Rate Case – Cost of Service

U-21297: DTE Electric Rate Case – Electric Vehicles

U-21389: Consumers Energy Electric Rate Case – Electric Vehicles

U-21461: Indiana Michigan Electric Rate Case – DG tariff rebuttal

U-21374: Consumers Electric Voluntary Green Pricing Case - rebuttal

U-21490: Consumers Energy Gas Rate Case – Cost of Service

U-21291: DTE Gas Rate Case - Cost of Service

U-21534: DTE Electric – Community Solar, EV, and Microgrid rebuttal

U-21585: CE Electric – Community Solar, EV, and Microgrid rebuttal

U-21816: Consumers Electric Voluntary Green Pricing Case - rebuttal

**DIRECT TESTIMONY OF KEVIN S. KRAUSE**
**CASE NUMBER U-21806**
**PART II**

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to provide Staff's presentation and recommendations with regard to gas cost-of-service (COS) and the cost-of-service study (COSS).

Q. Are you filing any exhibits?

A. Yes. I am sponsoring the following exhibits:

Staff Exhibit S-6, Schedule F-1.1, "Staff Cost-of-Service Study"

Staff Exhibit S-6, Schedule F-1.1b, "Staff Customer Charges"

Q. How did Staff perform its COSS?

A. Staff's COSS functionalizes, classifies, and allocates Consumers Energy Company's (the Company's) costs as projected by Staff to customers based on a set of schedules developed for such a purpose. Staff's COSS begins with a review of the Company's filed COSS provided by Company witness Samuel M. Geller. Input data was traced to original exhibits, and calculations for the functionalization, classification, and allocation were confirmed. Next, allocation schedule workpapers were verified in the same manner as the COSS. The COSS was then updated with adjustments provided by other Staff to capital expenditures, operations and maintenance (O&M) and other expenses, rate of return, cost of gas, and present revenue. Finally, cost allocation and the calculation of customer charges were performed as supported by Staff's positions in the case.

<u>Allocators</u>

Q. Is Staff proposing any allocator changes?

A. Yes. Staff is proposing two allocator changes, one for uncollectible expense, and another for Account 378.

Q. Why does Staff disagree with the Company's proposed allocation of uncollectibles?



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A. Although this method is the one that is currently approved for the Company, it is inappropriate as it does not reflect the reality of the way uncollectible costs are incurred or how they should be borne by the classes.

Q. What does Staff recommend?

A. Staff recommends an allocation based on revenue, as this reflects how the bills that may end up uncollectible are determined and also is how Consumers Electric (as well as DTE Gas and DTE Electric) allocates uncollectibles. In addition, this method properly reflects the fact that expenses related to uncollectible accounts are a general cost of doing business. Like for any other utility or business, there will inevitably be a certain portion of customers who do not pay their bills, otherwise there would be no uncollectible expense. Some customers will not pay their gas bill, but the number of similarly-served customers has no effect on any particular customer's willingness or ability to pay their bill. The reasons for which a customer's account becomes uncollectible have only to do with that customer's unique circumstance, not those of any other. For example, a customer on Residential Rate A that pays their bill in full has no more impact on an uncollectible account than a customer on Rate XXLT that pays its bill in full. Uncollectible expense should be shared by all customers consistent with how their overall costs are recovered by the Company: by revenue.

Q. Why is Staff proposing to change the allocator for Account 378 – Other distribution plant?

A. After examining the evidence provided by the Company, Staff found the detailed examination of Account 378 to be appropriate for allocation. Staff prepared a blended allocator that represents a reasonable allocation of that account in the COS. Details on

the allocator used as well as further explanation of Staff's position are presented in the testimony of Staff witness Nicholas M. Revere.

Customer Charges

Q. Does Staff have any other adjustments to the Company's projected test-year cost of service studies?

A. Yes. Staff modified the Company's calculation of customer charges.

Q. How did the Company calculate customer charges?

A. The Company calculated customer charges based on the method approved in the Company's previous gas rate case. However, the Company used a combination of historical and projected expenses.

Q. Did Staff calculate customer charges differently than the Company?

A. Yes. Staff's customer charges are calculated on Exhibit S-6, Schedule F-1.1b. Staff proposes to only rely on historical amounts for customer charges in the instant case. Test-year capital and O&M, as presented by the Company, are split into separate accounts or categories (e.g. distribution, storage, customer accounting) based on the historic composition of those accounts in relation to total historic capital and O&M. This treatment may be acceptable if the costs compositions did not change year to year, but that is not the case. Therefore, the Company's calculation fails to reflect projections of costs appropriate for inclusion in the customer charge. Utilizing only historical costs ensures that the Company's method of spreading projected costs does not include costs that are inappropriate for inclusion in the customer charge. Staff's calculation results in Staff recommendation for the residential customer charge of $19.00. Staff also recommends accepting the Company's proposed customer charge for rate GS-1; though

Staff's calculation could support a higher customer charge, Staff finds it apprfopriate to accept the Company's proposed charge in the instant case. All other customer charges are set by rate design.

Q. Can you explain why the increase in residential customer charge is so much, even in Staff's calculation?

A. Yes. The last several rate cases have been settled. In each case, Staff's calculations would have justified increased customer charges but the settlements either resulted in smaller increases, or in one case, no increase in the residential customer charge at all. This has resulted in the spread between the calculated customer charge and the approved customer charge growing larger over time.

Q. Please summarize your recommendations?

A. Staff recommends the following:

-Change the uncollectibles allocator to reflect the cost of doing business.

-Change the allocator for Account 378 to that supported by Staff witness Nicholas M. Revere.

-Accept the Staff proposed residential customer charge of $19.00 and Company proposed customer charge for GS-1.

Q. Does this conclude your testimony?

A. Yes.

**S T A T E  O F  M I C H I G A N**

**BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION**

*** * * ***

| | | |
|---|---|---|
| **In the matter on the Application of CONSUMERS ENERGY GAS COMPANY for authority to increase its rates for the distribution of natural gas and for other relief.** | **)** | **Case No. U-21806** |

# REBUTTAL TESTIMONY OF

# KEVIN S. KRAUSE

# MICHIGAN PUBLIC SERVICE COMMISSION

**May 14, 2025**

**REBUTTAL TESTIMONY OF KEVIN S. KRAUSE**
**CASE NUMBER U-21806**

Q. Are you the same Kevin S. Krause who filed direct testimony in the instant case?

A. Yes.

Q. What is the purpose of your rebuttal testimony?

A. The purpose of my rebuttal testimony is address arguments made relating to cost-of-service by ABATE witness Jessica York.

Q. Are you including any exhibits with your rebuttal testimony?

A. Yes, I am including Exhibit S-24.0.

Q. ABATE witness York discusses the alleged double counting issue as it relates to the Average and Peak method (A&P) on pages 26-31 of direct testimony. Does Staff agree this claimed double counting is an issue?

A. While Staff witness Nicholas M. Revere addresses whether or not the claimed double counting exists, even if it does, Staff does not agree it is a serious flaw. The average is calculated based on 365 days of class gas consumption. Only a portion of the peak day could be considered double counted. The average could be determined using the 364 days other than the peak day. The result of this would be that the average gas on the peak day would not be double counted. Also, the average for the year would not likely move much because although you would be removing the peak day from the calculation the other 364 data points would likely dominate the calculation.

Q. Can this be shown numerically?

A. Yes. The peak days' contribution to the average is the peak day divided by 365. The peak for transmission is 3,266,655 Mcf and the average is 843,112 Mcf.[1] The peak days' contribution to the average would be 3,266,655/365 or 8,950 Mcf. The

[1] Exhibit S-24.0



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recalculated average without the peak day is 834,162 Mcf, a reduction of just over 1 percent.

Q. What is Staff's conclusion?

A. Removal of the alleged double counting problem by removing the peak day from the average calculation would change the average by approximately 1 percent and passing this calculation through the allocator would have an extremely small impact on the allocator itself.

Q. Does the Average and Excess (A&E) method appear in the June 1989 version of the NARUC Manual?

A. No. There are only three methods mentioned by name are the coincident demand method, the non-coincident demand method, and the Average and Peak (A&P) method. It also includes "some modification or combination of the three"[2].

Q. Does the NARUC Manual state its preferred method?

A. No, the NARUC Manual gives reasons why an analyst may choose a method but does not provide recommendations. Furthermore, the manual does not say that one method is more reflective of the cost of service than any other method.

Q. ABATE witness York states that the A&E method is preferred to the A&P method;[3] does Staff continue to support A&P?

A. Yes. On the allocation of demand-related costs, the NARUC Manual states:

> There is a wide variety of alternative formulas for allocating and determining demand costs, each of which has received support from some rate experts. No method is universally accepted, although some definitely have more merit than others." (NARUC Manual, pg. 26).

[2] NARUC Manual, page 27.
[3] ABATE witness York direct, page 34.

> The most commonly used demand allocations for natural gas distribution utilities are the coincident demand method, the non-coincident demand method, the average and peak method, or some modification or combination of the three." (NARUC Manual, pg. 27).

Staff supports the use of the A&P methodology, one of the three most commonly used allocation methods for demand-related costs according to the NARUC Manual. Of the A&P method the NARUC Manual states:

> This method reflects a compromise between the coincident and noncoincident demand methods. Total demand costs are multiplied by the system's load factor to arrive at the capacity costs attributed to average use and are apportioned to the various customer classes on an annual volumetric basis. The remaining costs are considered to have been incurred to meet the individual peak demands of the various classes of service and are allocated on the basis of the coincident peak of each class. This method allocates cost to all classes of customers and tempers the apportionment of the costs between high and low load factor customers. (NARUC Manual, pp. 27-28).

Staff proposed using the A&P allocation method because it better reflects the classes' use of the system than the alternatives. High and low load factor customers use the distribution system differently, so it is not fair to allocate the costs for using that system as if it were used for a single purpose, whether that be to meet design day peak demand, average throughput, or class/individual customer demands. Because customer classes use the distribution system differently, it is reasonable to use an allocation method that combines how those disparate classes cause costs. The fact that this method also balances the interests of high and low load factor customers is an additional benefit of its use that stems directly from properly reflecting different uses of the system. Staff maintains that the most reasonable allocation method is A&P.

Q. For what other reasons should the A&P allocator be the preferred method of allocating distribution mains and related costs?

A. In the past, the Commission has properly recognized that there are sound reasons for allocating some portion of demand-related costs on the basis of non-peak throughput. See MPSC Case No. U-10150, Order, October 28, 1993, pg. 96. Here, the Commission quoted Staff witness William Aldrich, saying:

> "…any reasonable cost allocation methodology, such as the A&P method, recognizes that some portion of capacity must be allocated on the basis of non-peak usage. As correctly noted by Mr. Aldrich:
>
> > 'A gas distribution system is in some ways similar to a plant that produces two products. One product, peak day service, requires the entire capacity of the 'plant'. The other product, off-peak service, requires only a portion of the 'plant'. The plant has to produce both products to be economically viable; peak day load alone is insufficient to pay for the cost of building the plant, and off-peak service alone is not sufficiently desirable to many customers to allow for rates sufficient to recover the costs of building the plant. ABATE would have the Commission allocate the entire cost of the 'plant' to users of the peak day service product, because the whole plant is needed to produce that product. ABATE ignores the original cost causation question, i.e. would the plant have ever been built to produce only peak day service? The answer to that question is a resounding no.' (22 Tr. 4475-4476.) [Emphasis in original]" (MPSC Case No. U-10150, Order, October 28, 1993, pg. 96).

The reasons for the Commission's previous decisions, as well as the flaws in the position advanced by ABATE witness York, are still as relevant as they were when the Commission approved the Order in MPSC Case No. U-10150. Therefore, the Commission should continue to approve the use of the A&P allocator for distribution mains and related costs, as it is a reasonable allocation method which better reflects follows cost-causative principles than ABATE's proposal while also balancing the interests of all of the Company's customers. This results in fair and reasonable rates for all classes.

Q. Does Staff support ABATE witness York's A&E method to allocate mains and other costs?

A. No. The natural gas distribution system, both fixed in the short-term and variable in the long-term, is simultaneously planned to operate on peak days and used by customers every day. Further arguments against the A&E method are presented by Staff witness Revere.

Q. Does ABATE witness York cite other jurisdictions as support for the A&E method?

A. Yes. ABATE witness York includes examples from Pennsylvania and Missouri in support of their A&E allocation.

Q. What reasons does ABATE witness York provide for supporting these decisions?

A. Both the Pennsylvania and Missouri decisions cited the issue of double counting. The issue of double counting was addressed previously in this rebuttal testimony, as well as that of Staff witness Revere and Staff has shown the issue is irrelevant.

Q. What is Staff's overall conclusion regarding the mentioned jurisdictions?

A. Staff rejects the notion that these decisions have any relevance in this case for the reasons mentioned above.

Q. Does this conclude your rebuttal testimony?

A. Yes.

MS. STIRLING: Staff calls to be filed the qualifications and direct testimony of Nancy Rademacher that consists of a cover sheet and eight pages of questions and answers.

Ms. Rademacher sponsored ten exhibits associated with her direct testimony. These exhibits have been marked Exhibit S-6 Schedule F-2, Exhibit S-6 Schedule F-2.1, Exhibit S-6 Schedule F-2.2, Exhibit S-6 Schedule F-3, Exhibit S-6 Schedule F-4, Exhibits 9 through 9.4.

And then Ms. Rademacher also sponsored rebuttal testimony consisting of a cover sheet and three pages of questions and answers. There are no exhibits associated with Ms. Rademacher's rebuttal testimony.

Staff moves to bind into the record the qualifications, as well as the direct and rebuttal testimony, and associated exhibits of Nancy Rademacher.

JUDGE VARCHETTI: All right. Are there any objections to the admission of the direct and rebuttal testimony of Ms. Rademacher or any of the associated exhibits?

Hearing none, then, the testimony is bound into the record and the exhibits are admitted.

(Direct Testimony, Qualifications, and Rebuttal Testimony bound in)

**STATE OF MICHIGAN**

**BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION**

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Case No. U-21806

In the matter of the application of
**CONSUMERS ENERGY COMPANY**
for authority to increase its rates for the
distribution of natural gas and for other relief.

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# QUALIFICATIONS AND DIRECT TESTIMONY OF

# NANCY C. RADEMACHER

# MICHIGAN PUBLIC SERVICE COMMISSION

April 23, 2025

**QUALIFICATIONS AND DIRECT TESTIMONY OF**
**NANCY C. RADEMACHER**
**U-21806**

Q. Please state your name and business address.

A. My name is Nancy C. Rademacher. My business address is 7109 West Saginaw Hwy, Lansing, Michigan 48917.

Q. By whom are you employed and in what capacity?

A. I am employed by the Michigan Public Service Commission (MPSC or Commission) as a Departmental Analyst for the Rates and Tariff Section of the Regulated Energy Division.

Q. Please describe your educational background.

A. In 1995, I completed my Bachelor of Science in Mathematics with a minor in Economics from Grand Valley State University.

Q. What are your current responsibilities at the MPSC?

A. As an analyst, I participate in rate and tariff amendment cases under the direct supervision of the Rates and Tariff Manager. I am also responsible for updating the gas and electric bill comparison spreadsheets for the MPSC website and assist my section with various other tasks.

Q. Have you attended any seminars or other training courses relating to your current role?

A. Yes. In August 2023, I participated in Michigan State University's Institute of Public Utilities Annual Regulatory Studies Program Fundamentals Course. In October 2023, I participated in EUCI's Electric Utilities 101. In December 2023, I participated in EUCI's Natural Gas Utilities 101. In December 2024, I participated in EUCI's Advanced Rate Design for Cost Effective Tariffs.

Q. Have you previously presented testimony or participated in utility cases before the MPSC?



VERITEXT LEGAL SOLUTIONS

A. Yes. I have assisted or filed testimony in the following cases:

| Case Number | Company | Type of Case |
|---|---|---|
| U-21490 | Consumers Energy | Rate Case |

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to present Staff's position on Consumers Energy Company's (the Company) proposed rate design.

Q. Are you sponsoring any exhibits in this proceeding?

A. Yes, I am sponsoring the following exhibits:

Exhibit, Schedule and Title

S-6.0 Schedule F-2: STAFF Summary of Present and Proposed Revenue by Rate Schedule

S-6.0 Schedule F-2.1: STAFF Summary of Present and Proposed Rates by Rate Schedule

S-6.0 Schedule F-2.2: STAFF Calculation of Rate Design Targets and Allocation of Low-Income Provision Credits

S-6.0 Schedule F-3: STAFF Present and Proposed Revenue Detail

S-6.0 Schedule F-4: STAFF Comparison of Present and Proposed Monthly Bills

S-9.0 STAFF Development of Rates for Transportation ATL Services

S-9.1 STAFF Calculation of Test Year Discount and Carrying Cost Rates for the Customer Attachment Program

S-9.2 STAFF Calculation of Home Products Credit

S-9.3 Audit Response SA-CE-302

S-9.4 Audit Response SA-CE-236

Q. Were these exhibits prepared by you or under your supervision?

A. Yes, they were.

Q. How is your testimony structured?

A. My testimony is structured as follows:

1. General Rate Design
2. Summary

**1. General Rate Design**

Q. Does Staff agree with the Company's proposal to increase the Residential customer charge from $15.00 to $20.00?

A. No, Staff disagrees. Staff proposes a Residential customer charge of $19.00, as supported by Staff witness Kevin S. Krause.

Q. Does Staff agree with the Company's recommendation for the excess peak demand charge for Rate A-1 customers?

A. Staff recommends using the same method as the Company, setting the change in the excess peak demand charge to the same percentage change as in the residential rate customer charge. As Staff's rate design includes an increase of 27% in the residential customer charge, Staff recommends the same increase for the excess peak demand

charge, as shown in Exhibit No. S-6.0 Schedule F-2.1, page 1.

Q. Does Staff agree with the Company's recommendation to change the excess peak demand usage threshold from 45 Mcf to 76 Mcf?

A. No. Staff discovered through audit that the Company's proposed change to the excess peak demand usage threshold to 76 Mcf was an error, and the Company instead supports a change to the excess peak demand usage threshold to 92 Mcf.[1] Therefore, Staff supports updating the excess peak demand usage threshold from 45 Mcf to 92 Mcf for class A-1 customers to promote a more accurate and cost-based rate design.

Q. What is Staff's proposal for the General Service (GS) customer and distribution charges?

A. Staff's proposal for General Service charges can be found in Exhibit No. S-6.0, Schedule F-3, pages 3-5; the proposed Staff customer charge for GS-1 is supported by Staff witness Krause, while the others are the result of using the same breakeven-based rate design method as the Company.

Q. What is Staff's proposal for General Outdoor Lighting Service charges?

A. Staff's proposal can be found in Exhibit No. S-6.0, Schedule F-3, page 6.

Q. What is Staff's proposal regarding Small Transportation (ST) through Extra Extra Large Transportation (XXLT) customer and distribution charges?

A. Staff's proposal for Transportation customer charges can be found in Exhibit No. S-6.0, Schedule F-3, pages 7-10.

Q. Does Staff agree with the Company's proposed rates for Transmission Only Transportation Service Rate?

[1] Exhibit No. S-9.3

A. No. The proposed Transmission Only Transportation Service rates do not reflect the breakeven points of the associated rate schedules and therefore should not be used. In addition, the service provided to the Transmission Only Transportation Service customers has not been shown to differ in a way that supports separate rates for the breakeven-based classes.[2] For these reasons, all Transmission Only Transportation Service customers should be served on a single rate. Having a volumetric rate for the Transmission Only Transportation Service customers would be consistent with the Transportation Off-System Service Rate approved by the Commission for DTE Gas Company.[3]

Q. What rates does Staff support for Transmission Only Transportation Service Rate?

A. Staff supports the rates calculated by Staff in Exhibit No. S-6.0, Schedule F-3, page 11.

**Rate Stability Targets**

Q. How did Staff perform its rate design?

A. Staff first confirmed the Company's present revenue. Next, Staff adjusted rate stability targets and the designed rates to recover Staff's proposed revenue requirement allocated to the different rate classes consistent with Staff's cost of service study (COSS), performed by Staff witness Kevin S. Krause. Staff witness Krause also recommended a proposed customer charge different from the Company for rate A, which was then entered into the rate design model manually.

Q. How and why did Staff adjust rate stability targets?

A. Staff found that the stability targets used by the Company did not produce reasonable rate

[2] Exhibit No. S-9.4

[3] See DTE's natural gas rate book, original Sheet No. E-34.00, seventh revised sheet No. E-35.00, and first revised sheet No. E-35.01 under "TRANSPORTATION OFF-SYSTEM (FIRM) SERVICE RATE TOS-F"

increases across the customer classes. Staff used the COSS's percentage rate increases as the beginning stability targets. When those targets did not produce a reasonable rate design while considering the breakeven points, discussed further below, Staff decreased the stability target for GS-1 and GS-3 and increased the stability target for GS-2 until a reasonable rate design was attained.

Q. Does Staff agree with the Company's rate design method, which maintains the breakeven points between all GS and transportation rate schedules?

A. Yes, Staff agrees with the method the Company used to maintain breakeven points between GS and transportation rate schedules. However, Staff does not agree with the Company's proposed rate design targets and instead proposes rate design targets consistent with the results of Staff's COSS and proposed adjustments thereto.

Q. Why is it important to maintain economic breakeven points between the rate schedules?

A. It is important to maintain the economic breakeven points because, in order to have the revenue targets be reasonably attainable, customers should actually be on the rate they are proposed to be to the extent practicable. An effective breakeven point deters customers from switching rate classes, since being on another rate schedule would be more expensive. If these breakeven points were changed without cause, or without properly reflecting such a change in the determinants, the Company's ability to collect its targeted revenue requirement would be inappropriately impaired.

**Rate Implementation Date**

Q. When should rates for this case go into effect?

A. To allow more time to confirm accuracy of the rates and tariffs approved by the

Commission, Staff proposes that the rates and tariffs attached to the order in the instant case be given an effective date after a designated time period (Staff recommends fourteen calendar days, consistent with recent Commission orders) for all parties to review the calculations and tariff sheets. This time period gives all parties time to identify and notify the Commission of any errors, which ensures the rates and tariffs put into effect by the Company are reflective of the Commission's decisions. If no errors are found, then the rates and tariffs would go into effect at the end of the review period set in the order. If, however, errors are identified, corrections would be filed in the docket prior to implementation.

**Tariff Issues**

Q. Does Staff support any changes to the tariff sheets?

A. Staff supports updating tariff sheets to reflect changes in Staff proposed rates. Unless otherwise addressed in Staff's testimony, Staff has identified no issue with other tariff proposals made by the Company.

## 2. Summary

Q. Please summarize your positions and recommendations in your direct testimony.

A. My positions and recommendations are as follows:

1. Staff recommends using the same method as the Company to calculate the excess peak demand charge in the instant case.

2. Staff supports an increase in the excess peak demand threshold from 45 Mcf to 92 Mcf.

3. Staff supports a Transmission Only Transportation Service Rate calculated by Staff in

Exhibit No. S-6.0, Schedule F-3.

4. Staff proposes its own rate design for all rate schedules, reflecting Staff's proposed revenue requirement and COSS, which can be found in Schedule F-2.

Q. Does this conclude your testimony?

A. Yes, it does.

**S T A T E OF M I C H I G A N**

**BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION**

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| | | |
|---|---|---|
| **In the matter of the application of CONSUMERS ENERGY COMPANY for authority to increase its rates for the distribution of natural gas and for other relief.** | **)** | **Case No. U-21806** |

# REBUTTAL TESTIMONY OF

# NANCY C. RADEMACHER

# MICHIGAN PUBLIC SERVICE COMMISSION

**May 14, 2025**

Q. Are you the same Nancy C. Rademacher who filed direct testimony on behalf of the Michigan Public Service Commission Staff (Staff) in the instant case?

A. Yes, I am.

Q. What is the purpose of your rebuttal testimony?

A. The purpose of my rebuttal testimony is to present Staff's response to the commercial transportation volumes and related revenue adjustment taken in the direct testimony of Attorney General (AG) witness Sebastian Coppola, and Association of Business Advocating Tariff Equity (ABATE) witness Jessica A. York, regarding transportation rate design.

**Commercial Transportation Volume and Revenue Adjustment**

Q. Does Staff agree with AG witness Sebastian Coppola's calculation of adjustments to gas sales revenue in Exhibit No. AG-54?

A. Although I am not taking a position on behalf of Staff regarding the gas sales/delivery volume adjustment, the calculation of the associated revenue adjustment as outlined in Exhibit No. AG-54 should not be directly adopted should the Commission accept AG witness Coppola's adjustment. AG witness Coppola's calculation of the sales revenue adjustment is based on the multiplication of proposed incremental gas deliveries for commercial customers as allocated to the rate schedules by the current distribution charges for each rate schedule. While this method accurately determines the present distribution revenue impact of the sales forecast adjustment, it fails to appropriately adjust inputs to the Cost-of-Service Study (COSS) or incorporate changes to revenue and expenses associated with gas supply. If the Commission agrees with the sales



VERITEXT LEGAL SOLUTIONS

volume adjustments proposed by AG witness Coppola, those adjustments should also be included in all COSS and rate calculations to determine the appropriate revenue, expense, rate design, and COSS adjustments.

**Transportation Rate Design**

Q. In discussing if the Company's proposed rate design for transportation customers aligns with the results of its Preferred CCOSS, ABATE witness York claims "the remaining rate design reflects shifts in revenue requirement between the Transportation rate schedules in order to maintain existing economic breakeven points."[1] Does Staff agree?

A. Staff agrees the Company shifted revenue to maintain breakeven points. However, Staff's position is the minimal amount of revenue that was shifted by the Company to maintain existing breakevens does not lend support to ABATE witness York's position. The amount of revenue the Company shifted was $120,000 from XLT to LT as shown in Exhibit A-16 (SAS-3), Schedule F-2.2, which is less than 1% of the proposed revenue for the two rate schedules. In addition, most of the difference shown in Table JAY-3 is due to the allocation of low-income credits and the XXLT storage adjustment that occur in the rate design file rather than the COS. In addition, Staff's transportation rate design was developed without a shift in revenue between the Transportation rate schedules and maintains existing breakevens as shown in Exhibit No. S-6.0 Schedule F-2.2. It is also worth noting that there are two other adjustments made by both Staff and the Company that are larger than the breakeven adjustments, one for the Low-

[1] ABATE witness York Direct, p. 36.

Income Credits and one for the reallocation of storage from XXLT to the other transportation customers.[2] These adjustments occur during rate design rather than in the COS. For these reasons, ABATE's position is not supported by the claims of moving money to maintain breakeven adjustments.

Q. Please summarize your recommendations.

A. My recommendations are as follows:

1. If the Commission agrees with the sales volume adjustments proposed by AG witness Coppola, those adjustments should also be included in all COSS and rate calculations to determine the appropriate revenue, expense, rate design, and COSS adjustments.

2. The Commission should not consider differences between the COS results and proposed revenues to support the relief proposed by ABATE witness York.

Q. Does this complete your rebuttal testimony?

A. Yes, it does.

[2] Exhibit No. S-6.0 Schedule F-2.2

MS. STIRLING: Staff calls to be filed the qualifications and direct testimony of James La Pan that consists of a cover sheet and six pages of questions and answers. Mr. La Pan sponsored one exhibit associated with his direct testimony. This exhibit has been marked Exhibit S-7.

Staff moves to bind into the record the qualifications and direct testimony and the associated exhibit of Mr. La Pan.

JUDGE VARCHETTI: All right. Any objections to admitting the direct testimony of Mr. La Pan or his associated exhibit?

I am hearing none, so the testimony is bound into the record and the exhibit is admitted.

(Direct Testimony and Qualifications bound in)

**STATE OF MICHIGAN**

**BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION**

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Case No. U-21806

In the matter of the application of
**CONSUMERS ENERGY COMPANY**
for authority to increase its rates for the
distribution of natural gas and for other relief.

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# QUALIFICATIONS AND DIRECT TESTIMONY OF

# JAMES E. LA PAN

# MICHIGAN PUBLIC SERVICE COMMISSION

April 23, 2025

**QUALIFICATIONS AND DIRECT TESTIMONY OF**
**JAMES E. LA PAN**
**U-21806**

Q. Please state your name and business address.

A. My name is James E. LaPan and my business address is 7109 West Saginaw Highway, Lansing, MI.

Q. Who are you currently employed by and in what position?

A. My employer is the Michigan Public Service Commission (MPSC or Commission) and my job title is Public Utility Engineer.

Q. What are your responsibilities in your current position?

A. My current responsibilities consist of assisting with Staff's analysis of natural gas and electric utility depreciation rate case filings. This includes determining the remaining book value of current assets, performing life and net salvage analysis, and reviewing the terminal costs estimates associated with historic Manufactured Gas Plant (MGP) Facility remediation, as presented in utility natural gas rate case filings. Furthermore, as requested, I am involved in studies of all facilities in former and current natural gas and electric utility plants. Such studies are conducted through on-site review and examination via walk-throughs, along with interviews with Company subject matter expert personnel of each facility as needed. Additional reviews of facility operations, environmental compliance, asset retirement obligation, system and site integrity, and plant demolition and decommissioning costs are also part of my duties. As requested, I have provided technical presentations regarding specialized topics of interest; most recently, this involved an internal Commission Staff training session where I presented an explanation of the review criteria for MGP remediation activities and costs and how compliance and prudence are determined.



VERITEXT LEGAL SOLUTIONS

Q. Would you please describe your educational background and work experience?

A. I earned a Bachelor of Science in Biosystems Engineering from Michigan State University (MSU) in August 2006. Prior to attending MSU, I was in the honors program at Delta College. While attending Delta College, I was employed at Delphi Corporation as an engineering apprentice from May 2000 through August 2002. During this apprenticeship, I worked with engineering professionals to address technical issues, including state and federal regulatory compliance issues related to onsite electric generation, hazardous material handling, and wastewater treatment. I was directly involved in the activities surrounding the decommissioning and demolition of Delphi's Chassis Plant 2. I was also involved in the development of several programs and operational procedures that dealt with the capture and reuse of spent materials, in particular, waste sludge from Delphi's wastewater treatment facility. After transferring to MSU, I was employed by the Statewide Planning Section of the Michigan Department of Transportation (MDOT) in a student assistant position from June 2005 through June 2006. My duties included providing technical support for the implementation and assignment of federal grant money under the Congestion Mitigation and Air Quality Control (CMAQ) program for project proposals submitted. My assistance with the development of modeling and forecasting programs was used to aid in the qualification, quantification, and prioritization of those proposals.

Q. Have you attended any additional courses of study or any professional seminars?

A. Yes. I have regularly attended the annual meetings and attended the following classes offered by the Society of Depreciation Professionals (SDP): "Depreciation Basic," "Life

and Net Salvage Analysis," "Analyzing the Life of Real-World Property," and "Preparing and Defending a Depreciation Study" in September 2012, September 2013, September 2014, and September 2015, respectively. I last participated in annual training at the Society of Depreciation Professionals in 2017. While employed at the MPSC, I attended the Electric Utility Consultants, Inc (EUCI) annual conference on "Plant Retirement and Remediation: Mitigating Risk, Cost and Liability of Deactivated Assets" and the Institute of Public Utilities (IPU) advanced regulatory studies program. I last participated in annual training seminars in depreciation of regulated utilities provided by the National Association of Regulatory Utility Commissioners (NARUC) in 2018. In August 2006, I attended NARUC's two-week training program for regulatory professionals held each year on the campus of Michigan State University.

Q. Have you prepared testimony for any other proceedings?

A. Yes. I have prepared testimony for the following proceedings:

| Case Number | Company | Subject/Type |
|---|---|---|
| U-15506 | Consumers Energy Company | Rate Case |
| U-15702 | SEMCO Energy Gas Company | GCR Plan Case |
| U-15985 | Michigan Consolidated Gas Co. | Rate Case |
| U-15896 | Consumers Energy Gas Company | Rate Case |
| U-16125 | SEMCO Energy Gas Company | Capacity Involvement |
| U-16117 | Detroit Edison | Depreciation Case |
| U-16418 | Consumers Energy Company | Rate Case |
| U-16054 | Consumers Energy Company | Depreciation Case |
| U-16055 | Consumers Energy & Detroit Edison | Depreciation Case |
| U-16801 | Indiana Michigan Power Company | Rate Case |
| U-16855 | Consumers Energy Company | Rate Case |
| U-16938 | Consumers Energy Company | Depreciation Case |
| U-16999 | Michigan Consolidated Gas Company | Rate Case |
| U-16991 | DTE Electric Company | Depreciation Case |
| U-17643 | Consumers Energy Company | Rate Case |
| U-17882 | Consumers Energy Company Gas | Rate Case |

| | | |
|---|---|---|
| U-18124 | Consumers Energy Company Gas | Rate Case |
| U-18424 | Consumers Energy Company Gas | Rate Case |
| U-18452 | SEMCO Energy Gas Company | Depreciation Case |
| U-18467 | UPPCo | Depreciation Case |
| U-20118 | DTE Gas Company | Depreciation Case |
| U-20322 | Consumers Energy Gas | Rate Case |
| U-20359 | Indiana Michigan Power Company | Depreciation Case |
| U-20479 | SEMCO Energy Gas Company Gas | Rate Case |
| U-20642 | DTE Gas Company Gas | Rate Case |
| U-20650 | Consumers Energy Gas | Rate Case |
| U-20940 | DTE Gas Company | Rate Case |
| U-21148 | Consumers Energy Gas | Rate Case |
| U-21308 | Consumers Energy Gas | Rate Case |
| U-21384 | DTE Gas Company | Depreciation Case |
| U-21490 | Consumers Energy Gas | Rate Case |

Q. What is the purpose of your testimony in this case?

A. The purpose of my testimony is to present Staff's findings and support its recommendations regarding the reasonableness and prudence of the Consumers Energy Gas Company's (Company) request for recovery of expenditures actually incurred for environmental response activities at its former manufactured gas plant (MGP) sites in the 2024 calendar year.

Q. Are you supporting any exhibits in this case?

A. Yes. I am supporting the following exhibits:

Exhibit S-7 Costs associated with MGP remediation in 2024

Q. Was this exhibit prepared by you or under your direction?

A. Yes. Exhibit S-7 was provided by the Company in response to Staff discovery or audit questions.

MANUFACTURED GAS PLANT FINDINGS

Q. Please provide Staff's findings on the reasonableness and prudence of the environmental

response activities and associated costs incurred by the Company at its former MGP sites from January 1, 2024 through December 31, 2024.

A. Staff has determined that the Company's environmental response activities, as well as the actual costs incurred associated with those activities, are reasonable and prudent.

Q. How did Staff determine that the environmental response activities and their associated costs were reasonable and prudent?

A. Staff's determination was made from its analysis of the Company's activities throughout this time, on each site. This analysis includes a review of current Part 201 criteria compared to current site conditions, as well as, a review of the invoiced costs, the Company's future site use, ownership, and response activity goals. Additionally, Staff's on-site review of remedial activities and interviews with the Company's subject matter experts, including annual remedial activities updates provided by the Company, and continued conversations/communications with the Company's witness.

MANUFACTURED GAS PLANT – RECOMMENDATIONS

Q. What expenditures has the Company requested recovery of for its environmental response activities in this current case?

A. As stated by Company witness Heather M. Prentice, starting on page 15, line 6 through line 11 of her direct testimony, the Company is requesting approval of approximately $997,000 for deferral over 10 years. The actual amount requested by the Company is $996,525 found on Company Exhibit A-91 (HMP-2), line 24, column (c).

Q. What is Staff's recommendation for the Commission regarding the Company's request for approval of $996,525?

A. Staff recommends the Commission approve $1,539,724 as reasonably and prudently incurred costs for the environmental response activities at the Company's former MGP sites from January 2024 to December 2024.

Q. Briefly explain Staff's recommended increase of $543,199 for environmental response activities in this case.

A. Through its analysis of the MGP expenses actually incurred by the Company from January 2024 to December 2024, Staff found that the expenditures requested by the Company in its initial filing, as seen in the Company's Exhibit A-91 (HMP-2), included estimated and forecasted costs for activities that had not actually occurred and therefore can-not be reviewed by the Commission for their reasonableness and prudence. However, Staff, as part of its analysis, requested the Company to provide their updated environmental activity and associated costs through the end of calendar year 2024 and, as a result, finds that the Company reasonably and prudently incurred $1,539,724 for its environmental response activities at their former MGP sites from January 1, 2024 through December 31, 2024.

Q. Please describe Staff's Exhibit S-7.

A. Exhibit S-7 supports the delta between the Company's requested expenditures for MGP activities and their actual expenditures. This was provided to Staff as an attachment to the Company's response to audit questions.

Q. Does this conclude your testimony at this time?

A. Yes.

MS. STIRLING: Staff calls to be filed the qualifications and direct testimony of Theresa McMillan-Sepkoski that consists of a cover sheet and nine pages of questions and answers. Ms. McMillan-Sepkoski sponsored two exhibits associated with her direct testimony. These exhibits have been marked Exhibit S-8.1 and Exhibit S-8.2.

Staff moves to bind into the record the qualifications and the direct testimony and the associated exhibits of Theresa McMillan-Sepkoski.

JUDGE VARCHETTI: Any objections to binding in the direct testimony of Ms. McMillan-Sepkoski or her associated exhibits?

I am hearing none, so the testimony is bound into the record and the exhibits are admitted.

(Direct Testimony and Qualifications bound in)

**S T A T E  O F  M I C H I G A N**

**BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION**

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|---|---|---|
| **In the matter of the application of CONSUMERS ENERGY COMPANY for authority to increase its rates for the distribution of natural gas and for other relief** | ) ) ) ) ) | **Case No. U-21806** |

# QUALIFICATIONS AND DIRECT TESTIMONY OF

# THERESA MCMILLAN-SEPKOSKI

# MICHIGAN PUBLIC SERVICE COMMISSION

**April 23, 2025**

**QUALIFICATIONS OF THERESA MCMILLAN-SEPKOSKI**
**CASE NUMBER U-21806**
**PART I**

Q. Please state your name and business address.

A. My name is Theresa L. McMillan-Sepkoski. My business address is 7109 West Saginaw Hwy, Lansing MI, 48917.

Q. By whom are you employed and in what capacity?

A. I am employed by the Michigan Public Service Commission (MPSC or Commission) as an Audit Specialist in the Revenue Requirements Section of the Regulated Energy Division.

Q. What is your educational background?

A. I graduated in 1981 from Mott Community College with an A.A.S. degree in Accounting with a minor in Business Management. In June 2006, I graduated from Baker College with highest honors and a B.B.A. degree with emphasis in Accounting. Since becoming employed here at the Commission, I have participated in numerous MPSC training sessions and attended the National Association of Regulatory Utility Commissioners (NARUC) Advanced Regulatory Studies Program.

Q. Please describe your professional background.

A. Prior to my employment at the MPSC, I worked in accounting in the public and private sector for sixteen years after receiving my associate degree. I began my employment at the Shiawassee County Health Department as an Accounts Processor. From there my experience in accounting came from working for Federal Forge Inc., also known as Bharat Forge Ltd. from an entry level position in Accounts Payable and promoted to Controller. After that I worked for CSI Inc. as an Assistant Controller/Human Resource Administrator. In December 2006,

having completed my bachelor's degree, I began my employment with the Michigan Public Service Commission and have continued through the present.

Q. Briefly discuss your experience with the MPSC.

A. I have served as the lead auditor, case coordinator, and performed audit work in many types of cases for the MPSC. The types of cases have been gas and electric rate cases, Power Supply Cost Recovery (PSCR) and Gas Cost Recovery (GCR) reconciliation cases, Cooperative Times Interest Earned Ratio (TIER) review cases, and various tracking mechanism cases. I have also testified before the Commission on previous Revenue Requirement rate cases.

Q. Have you previously filed testimony before the MPSC?

A. Yes, I have filed testimony in the following cases:

U-15190 – Consumers Energy Company Gas Rate Case

U-15244 – Detroit Edison Company Electric Rate Case

U-15245 – Consumers Energy Company Electric Rate Case

U-15506 – Consumers Energy Company Gas Rate Case

U-16034-R – Wisconsin Electric Power Co. 2010 PSCR Reconciliation

U-16149-R – Consumers Energy Co. 4/10 – 3/11 GCR Reconciliation

U-16424-R – Wisconsin Electric Power Co. 2011 PSCR Reconciliation

U-17095-R – Consumers Energy Co. 2013 PSCR Reconciliation

U-17130-R – Michigan Gas Utilities Corporation 4/13 - 3/14 GCR Reconciliation

U-17133-R – Consumers Energy Co. 4/13 – 3/14 GCR Reconciliation

U-17317-R – Consumers Energy Co. 2014 PSCR Reconciliation

U-17334-R – Consumers Energy Co. 4/14 – 3/15 GCR Reconciliation

**QUALIFICATIONS OF THERESA MCMILLAN-SEPKOSKI**
**CASE NUMBER U-21806**
**PART I**

U-17691-R – DTE Gas 4/15 – 3/16 GCR Reconciliation

U-18124 – Consumers Energy Co. Gas Rate Case

U-18250 – Consumers Energy Co. Securitization Case

U-20134 – Consumers Energy Co. Electric Rate Case

U-20162 – DTE Electric Rate Case

U-20276 – Upper Peninsula Power Co. Electric Rate Case

U-20322 – Consumers Energy Gas Rate Case

U-20479 – SEMCo Energy Gas Co. Gas Rate Case

U-20561 – DTE Electric Rate Case

U-20642 – DTE Gas Rate Case

U-20650 – Consumers Energy Gas Rate Case

U-20697 – Consumers Energy Electric Rate Case

U-20940 – DTE Gas Rate Case

U-20963 – Consumers Electric Rate Case

U-21148 – Consumers Gas Rate Case

U-20836 – DTE Electric Rate Case

U-21224 – Consumers Electric Rate Case

U-21286 – Upper Peninsula Power Company Electric Rate Case

U-21291 – DTE Gas Rate Case

U-21297 – DTE Electric Rate Case

U-21308 – Consumers Gas Rate Case

U-21389 – Consumers Electric Rate Case

U-21461 – I&M Electric Rate Case

**QUALIFICATIONS OF THERESA MCMILLAN-SEPKOSKI**
**CASE NUMBER U-21806**
**PART I**

U-21490 – Consumers Gas Rate Case

U-21540 – Michigan Gas Utilities Corporation Gas Rate Case

U-21555 – Upper Peninsula Power Co. Electric Rate Case

U-21534 – DTE Electric Rate Case

U-21585 – Consumers Electric Rate Case

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to present the Michigan Public Service Commission Staff's (Staff) adjustments to Consumers Energy Company's (the Company, or Consumers) projected Employee Incentive Compensation Plan (EICP) costs included in Operations and Maintenance expense (O&M) and the 15-year amortization of cloud implementation costs for the Software as a Service (SaaS), for the test year ending October 31, 2026.

Q. Are you sponsoring any exhibits in this proceeding?

A. Yes, I am sponsoring the following exhibits:

| Exhibit | Title |
|---|---|
| S-8.1 | Company Response U21806-SA-CE-026 |
| S-8.2 | Company Response U21806-SA-CE-028 |

**Employee Incentive Compensation Plan (EICP) Expense**

Q. What is EICP expense?

A. EICP expense is a portion of an employee's pay that is dependent upon achieving target levels on performance measures.

Q. Has Consumers Energy requested recovery of EICP expense in this case?

A. Yes. The Company has included $1,546,000 for EICP expense in the revenue requirement per Company witness Amy M. Conrad's testimony, page 30, line 8, and Company Exhibit A-41 (AMC-3), page 1 of 2.

Q. What are the performance measures of the Company's EICP?

A. Company Exhibit A-39 (AMC-1) outlines the employee performance measures. The measures are categorized as operational measures. There are six operational

performance measures.

Q. How do employees earn the incentive compensation?

A. Employees earn EICP by achieving target levels in each performance measure. Examples of target levels found on Exhibit A-39 (AMC-1) page 2 of 4 are achieving less than or equal to 170 for the Electric Reliability (System Average Interruption Duration Index) and a Customer Experience Index of greater than or equal to 73, achieved at target level to earn 100% of the proposed EICP expense requested for recovery in this case. Per Company Witness Conrad, the Company has discontinued determining target levels at absolute goal achievement to individual banded goals that provide each measure with its own threshold, target, and maximum performance goal for achieving a certain level of payout.

Q. Describe the changes the Company has made to its request for inclusion of the EICP expense in rates.

A. First, the Company has excluded the costs for short-term incentive compensation related to financial measures. Secondly, it has included the costs of the short-term incentive compensation based on operational measures for the top five (5) officers in the revenue requirement. Prior to Consumers Energy electric rate case, Case No. U-21224, the Company had not included incentive compensation costs for the top five (5) officers.

Q. Does Staff support the Company's request for EICP expense based on operational measures in rates?

A. Staff supports the request for operational measures EICP expenses for non-union Employees in the amount of $1,546,000, but not for the EICP expenses for the

top five officers that have been included in the current case. The costs for the EICP incentive compensation for the top five officers for the projected test year are $ (See Staff Exhibit S-8.1)

Q. Please explain why Staff does not recommend the top five officers EICP expense being approved.

A. Staff has two points for not recommending including the top five officers incentive compensation. First, in Company witness Amy M. Conrad's testimony, pages 10-24, she discusses Consumers compensation philosophy. Employees' salaries should be comparable to the market median, within a target level plus or minus 5% of the market median, giving examples of Consumer's pay levels compared to market levels. On page 21, lines 14-22, officer compensation packages are targeted at the median or 50th percentile of the market.

Staff asked for the compensation level of the top five officers compared to market median. The Company declined to provide this information to Staff (see Staff Exhibit S-8.2, page 1 of 2) through audit responses. The Company instead offered for Staff to examine report extracts of the Pay Governance report, with conditions attached:

-Reviewed in the presence of an appropriate CMS representative

-Maintain the confidentiality of the extracts

-May not copy or distribute the extracts to any other party

-Used only for the sole purpose of this inquiry

-Exempt Pay Governance from any public disclosure/Freedom of Information request or open records acts (See Exhibit S-8.2, page 2 of 2).

Q. Did the Company provide access to the report extracts to Staff?

A. Yes, Staff went to the Company's satellite office and viewed the report extracts provided.

Q. What does Staff recommend after viewing these reports?

A. Staff recommends disallowance of the operational measures portion of EICP for the top 5 officers. Staff appreciated the Company taking the time and providing the report extracts, but the reports were anonymous to each executive, and only presented how Pay Governance calculates the market data. There was no financial presentation of the compensation data that Staff needed to examine to make a valid comparison.

**Amortization of Cloud Implementation Costs for SaaS**

Q. Please explain the Cloud Implementation costs for SaaS.

A. These costs are part of the SAP S/4HANA implementation project.

Q. What is the Company requesting in the current rate case?

A. The Company is requesting approval for a 15-year amortization of these costs so that the costs are spread over a longer period of time to minimize the impact on customer rates.

Q. Does Staff approve the Company's request for the 15-year amortization of the Cloud Implementation costs for SaaS?

A. Yes, Staff recommends approval of the 15-year amortization of these costs. Please refer to Staff Witness Zichi's testimony for further recommendations regarding the SAP S/4 HANA upgrade.

Q. Does this conclude your testimony?

A. Yes, it does.

MS. STIRLING: Staff calls to be filed the qualifications and direct testimony of Brittany Klocke that consists of a cover sheet and 21 pages of questions and answers. Ms. Klocke sponsored 50 exhibits associated with her direct testimony. These exhibits have been marked Exhibit S-11.1 through Exhibit S-11.50.

The Staff moves to bind into the record the qualifications and direct testimony and to admit the associated exhibits of Ms. Brittany Klocke.

JUDGE VARCHETTI: Are there any objections to binding in the direct testimony of Ms. Klocke or admitting any of the associated exhibits?

I am hearing none, so the testimony is bound into the record and the exhibits are admitted.

(Direct Testimony and Qualifications bound in)

**S T A T E OF M I C H I G A N**

**BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION**

*** * * ***

| | | |
|---|---|---|
| In the matter of the application of | ) | |
| **CONSUMERS ENERGY COMPANY** | ) | Case No. U-21806 |
| for authority to increase its rates for the | ) | |
| distribution of natural gas and for other relief. | ) | |
| _____ | ) | |

# QUALIFICATIONS AND DIRECT TESTIMONY OF

# BRITTNEY KLOCKE

# MICHIGAN PUBLIC SERVICE COMMISSION

**April 23, 2025**

**QUALIFICATIONS OF BRITTNEY KLOCKE**
**CASE NUMBER U-21806**
**PART I**

Q. Please state your full name and business address.

A. My name is Brittney Klocke and my business address 7109 West Saginaw Highway, Lansing, MI 48917.

Q. By whom are you employed and in what capacity?

A. I am employed by the Michigan Public Service Commission (MPSC or Commission) as a Senior Analyst in the Data Access, Privacy and IT (DAPIT) Section of the Customer Assistance Division (CAD).

Q. Please describe your educational background.

A. I earned a Bachelor of Arts degree in Political Science from Miami University in 2006 and a Juris Doctor degree from Michigan State University College of Law in 2009.

Q. Please describe your professional experience.

A. I began my professional career with the State of Michigan in 2010, when I was hired as an Eligibility Specialist with the Department of Health and Human Services (DHHS). While with DHHS, I worked in a Specialized Medicaid Unit that reviewed retroactive and opened ongoing Medicaid cases.

In 2011, I accepted a position with the Department of Treasury (Treasury) as a Field Officer in the Collection Services Bureau. In that role, I was primarily tasked with performing research and analysis assignments related to various tax laws administered by Treasury. That entailed conducting field calls at businesses all over Michigan to verify taxpayer compliance and registration status, as well as identifying complex schemes related to tax avoidance and fraud.

**QUALIFICATIONS OF BRITTNEY KLOCKE**
**CASE NUMBER U-21806**
**PART I**

In July 2022, I accepted my current position with the MPSC. In this role, I perform analysis of utilities' rate case recovery requests related to Customer Experience and Information Technology (IT).

Q. Have you received any work-related training since your employment with the MPSC?

A. Yes. I attended Michigan State University's Institute for Public Utilities' (IPU) Annual Regulatory Studies Program in August of 2022. In September of 2022, I attended IPU's Accounting & Ratemaking Course. In March of 2023, I attended the National Association of Regulatory Utility Commissioners' Rate Case Basics course.

Q. Have you previously filed testimony before the Commission?

A. Yes.

Q. Please list the cases in which you have filed testimony before the Commission.

A. I filed testimony in Case No. U-21308, the Consumers Energy gas case, Case No. U-21297, the DTE electric case, Case No. U-21389, the Consumers Energy electric case, Case No. U-21461, the Indiana Michigan Power Company electric case, Case No. U-21490, the Consumers Energy gas case, U-21540, the Michigan Gas Utilities Corporation gas case, Case No. U-21534, the DTE electric case, and Case No. U-21585, the Consumers Energy electric case.



VERITEXT LEGAL SOLUTIONS

**DIRECT TESTIMONY OF BRITTNEY KLOCKE**
**CASE NUMBER U-21806**
**PART II**

Q. What is the purpose of your testimony in this proceeding?

A. The purpose of my testimony is to present MPSC Staff's (Staff) recommendations regarding Consumers Energy Company's (CE or the Company) request for recovery of proposed expenditures for Customer Information Technology (IT) projects and Customer Experience and Operations areas, as detailed in Company Exhibits A-20 (SHB-5) CONF and A-12 (JRB-1), Schedule B-5.3.

Q. Are you sponsoring any exhibits in this proceeding?

A. Yes, I am sponsoring the following exhibits:

- S-11.1: Audit Response U21806-SA-CE-416
- S-11.2: Audit Response U21806-SA-CE-417
- S-11.3: Audit Response U21806-SA-CE-418
- S-11.4: Audit Response U21806-SA-CE-419
- S-11.5: Audit Response U21806-SA-CE-409
- S-11.6: Audit Response U21806-SA-CE-411
- S-11.7: Audit Response U21806-SA-CE-191
- S-11.8: Audit Response U21806-SA-CE-327
- S-11.9: Audit Response U21806-SA-CE-328
- S-11.10: Audit Response U21806-SA-CE-330
- S-11.11: Audit Response U21806-SA-CE-331
- S-11.12: Audit Response U21806-SA-CE-332
- S-11.13: Audit Response U21806-SA-CE-333
- S-11.14: Audit Response U21806-SA-CE-334
- S-11.15: Audit Response U21806-SA-CE-335



VERITEXT LEGAL SOLUTIONS

- S-11.16: Audit Response U21806-SA-CE-369
- S-11.17: Audit Response U21806-SA-CE-370
- S-11.18: Audit Response U21806-SA-CE-371
- S-11.19: Audit Response U21806-SA-CE-191_Baker_ATT_1
- S-11.20: Audit Response U21806-SA-CE-123
- S-11.21: Audit Response U21806-SA-CE-124
- S-11.22: Audit Response U21806-SA-CE-125
- S-11.23: Audit Response U21806-SA-CE-126
- S-11.24: Audit Response U21806-SA-CE-127
- S-11.25: Audit Response U21806-SA-CE-128
- S-11.26: Audit Response U21806-SA-CE-233
- S-11.27: Audit Response U21806-SA-CE-303
- S-11.28: Audit Response U21806-SA-CE-304
- S-11.29: Audit Response U21806-SA-CE-305
- S-11.30: Audit Response U21806-SA-CE-307
- S-11.31: Audit Response U21806-SA-CE-308
- S-11.32: Audit Response U21806-SA-CE-309
- S-11.33: Audit Response U21806-SA-CE-310
- S-11.34: Audit Response U21806-SA-CE-312
- S-11.35: Audit Response U21806-SA-CE-313
- S-11.36: Audit Response U21806-SA-CE-326
- S-11.37: Audit Response U21806-SA-CE-341
- S-11.38: Audit Response U21806-SA-CE-342

• S-11.39: Audit Response U21806-SA-CE-343

• S-11.40: Audit Response U21806-SA-CE-345

• S-11.41: Audit Response U21806-SA-CE-347

• S-11.42: Audit Response U21806-SA-CE-348

• S-11.43: Audit Response U21806-SA-CE-349

• S-11.44: Audit Response U21806-SA-CE-350

• S-11.45: Audit Response U21806-SA-CE-351

• S-11.46: Audit Response U21806-SA-CE-352

• S-11.47: Audit Response U21806-SA-CE-372

• S-11.48: Audit Response U21806-SA-CE-377

• S-11.49: Audit Response U21806-SA-CE-378

• S-11.50: Audit Response U21806-SA-CE-346

Q. Were these exhibits prepared by you or under your supervision?

A. Yes.

Q. Please provide an overview of your testimony.

A. I am recommending and will be discussing adjustments for the following projects: Click to Chat, Web Chat AI and Self-Service Mobile Application enhancements; both of which fall under the greater Product Family Enhancement – Customer – Capital and the Low Moderate Income Customer Support Enhancement.

Q. What are Staff's recommendations regarding the Click to Chat project?

A. Staff is recommending a disallowance of $45,683 in capital expenditures for the historic year ended 12/31/2023, as well as $2,958 in capital expenditures for the bridge year period ended 12/31/2024. (Staff Exhibit S-19.0, line 5.) This

recommended adjustment corresponds with Company Exhibit A-20 (SHB-5), pages 1 and 8, lines 20 and 140.

Q. Why is Staff recommending disallowance of the requested costs for the Click to Chat project?

A. Consistent with Staff's position in Case Nos. U-21490 and U-21585, Staff recommends disallowance of the requested costs for this project because Staff finds the project does not offer any new technology or features that are innovative, nor does it represent any cost savings. Per Company Exhibit A-20 (SHB-5), pages 1 and 8, lines 20 and 140, the Click to Chat project is described as a platform that customers can use to engage in a chat conversation with customer service agents using the Company's website. The Company was asked in audit about any cost savings that will be associated with this project and it admitted that there are none projected. (Staff Exhibit S-11.3.) Indeed, the same agents who are part of the Company's Business Center and who answer live calls will be responsible for interacting with customers using the Click to Chat feature. (Staff Exhibit S-11.2.) The Company instead intends for this project to offer another contact channel for customers and does not take into account that the project will not provide any long-term monetary savings or cost reductions. (Staff Exhibit S-11.3.)

Q. Please discuss other reasons Staff recommends a disallowance for the Click to Chat project.

A. In addition to the reasons stated above, Staff recommends disallowing the Click to Chat project because a reduction in calls to the call center is not anticipated from

this project and chats will be handled by a live agent. (Staff Exhibit S-11.3.) Because the Company plans to train current customer service representatives (CSR) to use the tool and those same CSRs will handle Click to Chat requests, there is no anticipated reduction in customer service agents, and, once again, no anticipated costs savings in terms of the call center. (Staff Exhibit S-11.2.)

Staff also has concerns that just 314 uses of Click to Chat have been reported by the Company's agents. (Staff Exhibit S-11.1.) For a project that has now been available for over three years, usage is very low. In that same audit response, the Company stated that it currently has "no tracking regarding how many of their [customers'] problems/issues were fully resolved using this feature." (Staff Exhibit S-11.1.) Staff finds it troubling that the Company is not tracking the results of this project in an effort to measure its success.

Additionally, any major issues customers are experiencing will require assistance from a live customer service agent, and therefore must be conducted during Business Center hours, 8:00am-4:30pm, Monday-Friday. (Staff Exhibit S-11.2.) Customers will be able to report outages using Click to Chat 24/7, yet customers already have mechanisms in which to do so through other channels, such as the website itself.[1] Staff believes it is inevitable that many requests which start as Click to Chat will be escalated to a phone call or email inquiry, and wonders how useful the Click to Chat option will be beyond the most basic of inquiries/requests. Furthermore, everything the Click to Chat option can do is

[1] *See* Consumers Energy Company website homepage, available online at https://www.consumersenergy.com, accessed April 8, 2025.

already available on the Company's website, such as outage reporting and status updates, Stop, Start, Transfer service, reviewing or updating account information, and Staff does not support a redundant option that costs money and offers customers nothing new for that money.[2] Staff therefore recommends the Commission disallow all costs associated with the Click to Chat project.

Q. What are Staff's recommendations regarding the Product – Family Enhancements – Customer – Capital project?

A. Staff is recommending disallowance of costs related to the Web Chat Artificial Intelligence project, Customer Self-Service Mobile Application project enhancements, and Low Moderate Income Customer Support Enhancements, all located within this project. These disallowances total $1,905,494 in capital and $21,439 in O&M expenditures. (Staff Exhibit S-19.0.) Detailed breakdowns of the costs for these projects will be discussed in testimony.

Q. What are Staff's recommendations regarding the Web Chat Artificial Intelligence (AI) project?

A. Staff is recommending full disallowance of the costs requested for the Web Chat AI project, representing $180,565 in capital expenditures and $14,929 in O&M for the test year ending 10/31/2026. This project falls under the larger Product Family Enhancements – Customer – Capital project. (Staff Exhibit S-11.19, line 26.)

[2] *See* Consumers Energy Company website homepage, available online at https://www.consumersenergy.com, accessed April 8, 2025.

Q. Why is Staff recommending disallowance of the requested costs for the Web Chat AI project?

A. In the same vein as the foregoing reasons for Staff's recommended disallowance of the Click to Chat project, Staff feels the Web Chat AI project offers technology that is redundant and not worth the cost. As described by the Company in an audit response, the Web Chat AI "will utilize an AI-based chatbot to allow customers to 'chat' with a computer to find answers to more routine questions/concerns." (Staff Exhibit S-11.10.) Further, it was stated that the Company plans to have the Web Chat AI tool use information from the Company's website "as its primary source to assist customers." (Staff Exhibit S-11.11.) In essence, the Web Chat will simply be aggregating information that is already available to customers on the Company's website. Staff has and does support the Company's planned website redesign and feels it would be a much better use of Company resources – and ratepayer money – to update the website to make any general, frequently asked questions easily found.

Q. Please discuss other reasons Staff recommends a disallowance for the Web Chat AI project.

Staff is troubled that the Company's website redesign has been put on hold yet again, and that there is no current timeline for it. (Staff Exhibit S-11.5.) In settled Case No. U-21224, the Company requested $7,828,549 in capital expenditures and $1,101,600 in O&M for the website redesign.[3] Per the Company, the planned

[3] *See* U-21224, Hale 7 TR 2029.

redesign will include, among other things, "User-Friendly Navigation" that will help to simply and make navigation intuitive, as well as "Enhanced Accessibility" that will ensure "the site is accessible to all users." (Staff Exhibit S-11.6.) These updates would essentially provide the same kind of information and accessibility the Web Chat AI tool is supposed to and represent a better and more comprehensive use. The Company notes that the Web Chat AI is meant to address customers' common inquiries such as "more information about their bill, how to address their usage, insights into the charges on their bill, making a payment, programs available to them, reasons for an outage, help logging into the website, etc." (Staff Exhibit S-11.16.) Staff thinks these examples are things that should already be easily found on the Company's website, and if not, the issue could easily be mitigated by developing a comprehensive frequently asked questions page on its website, so that customers could easily find general information, like what is mentioned above. The fact is, any customer who will use the Web Chat necessarily has a certain level of comfort navigating a website, so Staff questions why they would need the Web Chat to help them find information they should already be able to find on their own.

Finally, Staff takes issue with the fact that no reduction in overall costs is anticipated from the Web Chat AI. (Staff Exhibit S-11.15.) Again, Staff does not see the value of this project when it will cost ratepayers money and merely offer information that should already be on the Company's website. According to the Company, the purpose of the Web Chat AI is "to allow customers to better self-serve for certain tasks that might drive unnecessary calls into the customer

contact center." (Staff Exhibit S-11.14.) Staff does see value in customers' ability to self-serve using the Company's website, but is not persuaded that an AI chatbot is the best way for this to happen. As has been stated before, updating the Company's website to make it more user friendly and easy to navigate will accomplish the same result and is a more prudent use of money.

Q. What are Staff's recommendations regarding the Customer Self-Service Mobile Application (App) expenditures included in the Product Family Enhancements – Customer – Capital project?

A. Consistent with every case it has been presented in, Staff is recommending full disallowance of costs requested for the Mobile Application. This represents a decrease of $61,562 in historical capital costs for the year ended 12/31/2023, $274,116 in capital costs for the year ended 12/31/2024, $598,472 in capital costs for the year ending 12/31/2025, and $550,025 in capital costs and $6,510 in O&M costs for the projected test year ending 10/31/2026. (Staff Exhibit S-11.19.) The costs for the Mobile App in this case are represented by enhancements that fall under the larger Product Family Enhancements – Customer – Capital project, which corresponds with Company Exhibit A-20 (SHB-5), pages 2, 10, 17, and 22, on lines 29, 145, 244 and 323.

Q. Why is Staff recommending a full disallowance of costs requested for the Mobile App?

A. Staff's position regarding the Mobile App has remained the same in every case it has been presented in, starting with Case Nos. U-20697, U-20963, U-21224, U-21389, electric cases, and Case Nos. U-21148, U-21308, and U-21490, gas cases.

In each of those cases, Staff's position is that the Mobile App represents functionality that is duplicative of the Company's website, and is therefore unnecessary and its over $10 million total costs should not be passed on to ratepayers.[4] The App represents a functionality that is redundant to that offered by the Company's website and the Company has not proven the need for a mobile application. Staff has made the argument against the Mobile App because the Company has never conclusively proven a need for such an application or customers' interest in it.

Q. Can you please articulate in additional detail why Staff finds the need for the Mobile App – and thus any enhancements to it – has not been proven?

A. Yes. The Company also states that the App "does not include the entirety of the website's information" and Staff questions why this technology is something ratepayers should have to fund since it is redundant to that of the website and offers less functionality.[5] Staff has consistently supported the Company's website redesign, and believes that the Company should have been focusing on that in terms of money spent. As mentioned earlier in this testimony, Staff was therefore surprised to learn, again via an audit response, that the Company has put its website redesign on hold. (Staff Exhibit S-11.5.)

Q. Does Staff have any additional thoughts regarding the proposed disallowance of the costs requested for the Mobile App?

[4] *See* U-21490 Company exhibit A-20 (SHB-5), line 22.
[5] *See* U-21490, Mclean 2 TR 798.

Yes. Staff is concerned the requested costs for 2025 and 2026 also include unspecified costs that are classified as "emergent." (Staff Exhibits S-11.19 and S-11.8.) Similar to costs requested for contingency expenses, emergent work expenses allow the Company to spend on projects without the ability for Staff to fully analyze and understand where those expenditures are being allocated to, therefore, Staff and intervenors do not have the opportunity to evaluate the costs for reasonableness and prudence. It is important that the Company does not recover more than it actually needs, and to prevent the Company from potentially over-earning – leading to higher costs for ratepayers – the Commission should disallow the requested emergent costs for the above-listed projects. In addition, two of the enhancements included for 2025 and 2026 – App Support Center and App Login Enhancements – have cost estimates that are not yet completed. (Staff Exhibit S-11.9.) Staff is not comfortable with the unknown nature of those costs and like emergent costs, must ensure that the requested costs are reasonable and prudent, which cannot be done when the costs are unknown. Therefore, at a minimum, Staff recommends the Commission disallow expenditures associated with these emergent and unknown cost requests for the Mobile App enhancements in the amount of $598,472 for 2025 and $550,025 in capital and $6,510 in O&M costs for 2026.

Q. What are Staff's recommendations regarding the Low Moderate Income (LMI) Customer Support Enhancement project?

A. Staff recommends full disallowance of the requested costs for the LMI Customer Support Enhancement, which represents $1.9 million in capital expenditures for

the test year ending 10/31/2026, which corresponds with Company Exhibit A-12 (JRB-1), Sch B-5.3. There is an additional $240,754 in capital expenditures for the bridge year period ending 12/31/2025 that fall under the Product Family Enhancements – Customer – Capital project and Company Exhibit A-20 (SHB-5).[6] (Staff Exhibit S-11.19.)

Q. Why is Staff recommending disallowance of the requested costs for the LMI Customer Support Enhancement?

A. According to the Company, the LMI Customer Support Enhancement is meant to make "interactions more accessible, supportive, and efficient for low- to-moderate income (LMI) customers." (Staff Exhibit S-11.20.) The project is also designed to support those LMI customers with reducing their "utility bill expenses by driving greater awareness and enrollment into eligible programs and services."[7]

While this sounds good on paper, Staff has attempted, through numerous rounds of audit questions, to ascertain exactly what the LMI Customer Support Enhancement will do or will offer customers, and still does not have a clear answer. Even when the Company was asked to provide a "roadmap" of sorts to demonstrate how this project will function, the tangible results remained unclear to Staff. Below I will discuss the four core functions of the LMI project and provide Staff's opinion on them.

Q. Please discuss the first core function of the LMI project.

[6] Prefiled direct testimony of Company witness Jessica R. Byrom, pages 17-18.
[7] Prefiled direct testimony of Company witness Jessica R. Byrom, p. 18.

A. The first core function of the LMI project is Simplified Enrollment. According to the Company, this will consist of the following: streamlining the "user flow to allow customers to find and enroll in relevant programs," "creating a centralized platform where customers can view all available assistance programs in one place," providing "clear, step-by-step guidance throughout the enrollment process to minimize confusion and errors," and ensuring the enrollment process is mobile-friendly. (Staff Exhibit S-11.20.) This function is projected to cost $600,000. (Staff Exhibit S-11.22.) Staff frankly does not understand why this information regarding enrollment is not already available to customers and is unclear why the Company needs so much money to allow customers to enroll in applicable programs. To be clear, this objective of the project is not creating new programs, but is instead simply making it more clear where customers can find these programs and enroll in them. Staff wonders why this is something that was not already in place to assist customers. As has been stated many times before in this testimony, Staff strongly feels that the Company updating their website to make information such as this standard would be a much better use of money.

Q. Please discuss the second core function of the LMI project.

A. The second core function of the LMI project is Proactive Communications and Program Awareness. This is described as building "the capability to proactively identify and reach out to customers who are showing early signs of crisis. This involves using data analytics to detect customers at risk and initiating contact to educate them about available assistance options." (Staff Exhibit S-11.20.) It will also direct customers to the "streamlined, digital flow" and "implement education

initiatives to increase awareness about assistance programs and how to access them. This will involve targeted communication campaigns and partnerships with community organizations." (Staff Exhibit S-11.20.) Finally, customers will be offered personalized communication options, allowing them to choose their preferred method of contact. (Staff Exhibit S-11.20.) This function is projected to cost $400,000. (Staff Exhibit S-11.22.) According to the Company, customers are already informed on an annual basis of the availability of payment programs and energy waste reduction (EWR) services. (Staff Exhibit S-11.34.) Residential customers, regardless of income, are given outreach via direct mail and email for information about EWR, demand response, and Renewable Energy Programs. (Staff Exhibit S-11.34.) Given this, Staff struggles to see why an additional $400,000 in outreach is needed at this point.

According to an audit response, the Company plans to allocate $150,000 to proactive outreach and marketing, specifically targeting customers "showing early signs of crisis." (Staff Exhibit S-11.31.) The issue with this is that Staff does not believe that the Company has a surefire way to reach any and all customers who could be in crisis. In an uncertain economic climate, virtually anyone could be in crisis with the loss of a job, unexpected bill, medical emergency, etc., and Staff believes this information should therefore be available to all customers, not just those the Company defines as low-to-moderate income. As defined by the Company, a crisis is defined "as a situation in which a customer is facing significant financial hardship, particularly related to their energy bills." (Staff Exhibit S-11.42.) Further, a "customer in crisis," as defined by the

Company, is someone "with a past due balance who is at risk of shutoff or is currently shut off." (Staff Exhibit S-11.42.) As stated previously, Staff is not convinced that the Company's definition of customers in crisis adequately captures all those customers who *could* end up in crisis, and therefore believes all customer classes – not just those identified as low-to-moderate income – should have access to the information the LMI project provides. In Staff's opinion, the best avenue to disseminate this information is via the Company's website redesign, not a new, very expensive project. In addition, it was revealed that these outreach materials have not yet been developed. (Staff Exhibit S-11.28.) To Staff, this indicates that the Company has not yet done its due diligence in preparing to launch this project.

Q. Please discuss the third core function of the LMI project.

A. The third core function of the LMI project is New and Improved LMI Offerings. This is described as integrating "existing offerings such as payment plans, EWR, demand response, and renewable energy programs. This integration will provide customers with a comprehensive support system, ensuring they can easily identify and access the best options to reduce their energy burden without having to search extensively." (Staff Exhibit S-11.20.) This function will also redesign programs to better serve LMI customers, "making them more accessible and user-friendly." (Staff Exhibit S-11.20.) This function is projected to cost $700,000. (Staff Exhibit S-11.22.) Once again, this facet of the LMI project is a very costly one that Staff does not fully understand the need for. Staff is perplexed why a new program such as this one would need such expensive "improvements" already.

Also, the Company stated in an audit response that "several maintenance and annual updates" are anticipated as part of this project. (Staff Exhibit S-11.36.) This means that more costs for improvements to the LMI project – in addition to the $700,000 being requested here – can and very likely will be requested in the future, and Staff has no way of knowing at this time how much those costs will be. (Staff Exhibits S-11.32 and S-11.36.) There is potential for the costs to snowball out of control, and it is unclear at this point what the money would even be spent on.

Q. Please discuss the fourth core function of the LMI project.

A. This fourth core function is Continuous Improvement and Feedback, which is described as the Company collecting feedback from customers and stakeholders to "continuously improve the user flow and outreach strategies," as well as using customer feedback to "identify and address any barriers to program participation" and implementing a "feedback loop that allows customers to easily share their experiences and suggestions for improvement." (Staff Exhibit S-11.20.) This function is projected to cost $200,000 and will establish performance and feedback metrics. (Staff Exhibits S-11.22 and S-11.23.) In particular, Staff takes issue with the Company projecting to spend $50,000 on "Customer Satisfaction." (Staff Exhibit S-11.33.) Per the Company's response, no clear difference between the three facets of this core function is shown; the $50,000 projected to be spent on "Responsive Adjustments," the $100,000 to be spent on "Data-Driven Enhancements," and the $50,000 for "Customer Satisfaction" all show overlap and do not justify their disparate cost requests. (Staff Exhibit S-11.33.) Again, it

appears the cost requests and the overall LMI project itself is too premature to be deemed reasonable and prudent.

Q. Please discuss other reasons Staff recommends a disallowance for the LMI Customer Support Enhancement project.

A. A main reason Staff does not support this project is because Staff does not believe this project will do anything to fix or prevent the root causes of customers either in or on the brink of crisis. The LMI project will not reduce customers' energy burden, even if they are able to utilize a payment plan, select their due date, or anything else – these solutions are mere band aids to the larger root problem of energy unaffordability. (Staff Exhibits S-11.40 and S-11.44.) Indeed, asking ratepayers to fund this project through rates – at a cost of over $2 million – frankly defies logic.

Additionally, on the Company's website there is already a link to Payment Plans and Assistance areas.[8] When the Company was asked how the LMI project will change or enhance the current website options, the Company answered that this project will provide streamlined navigation, provide a more user-friendly experience, collate comprehensive information regarding programs, and offer continuous improvements to the webpages, among other things. (Staff Exhibit S-11.41.) As mentioned above, Staff would prefer the Company invest time and money into updating the website, making this information easily

[8] *See* Consumers Energy Company Payment Plans & Assistance webpage, available online at https://www.consumersenergy.com/residential/account-and-billing/billing-and-payment/payment-assistance, accessed April 8, 2025.

accessible to all customers. Staff sees no reason to support the funding of this $2 million project when the information this project would provide should already be available on the Company's website.

There are no projected overall costs savings at this point that will be associated with this project. (Staff Exhibit S-11.35.) The "benefits" of this project the Company posits as rationale for its funding are nebulous and do not justify their high costs. (Staff Exhibit S-11.35.) Staff does not understand how a project projected to cost *at least* $2 million has such vague benefits as "better understanding of LMI customer needs, improved customer identification and targeting, increased program participation, and economies of scale with centralized enrollment." (Staff Exhibit S-11.35.)

Finally, the Company claims that the LMI Customer Support project "delivers on the priorities of the MPSC's Energy Affordability and Accessibility Collaborative (EAAC) and Low-Income Energy Policy Board" in three ways: by "integrating energy assistance programs with energy waste reduction initiatives to provide holistic support to LMI customers," introducing a "streamlined enrollment process designed to enhance customer access to energy assistance and energy waste reduction solutions," and enhancing "customer awareness" and fostering engagement by "incorporating educational initiatives that highlight available assistance programs and energy-saving practices."[9] (Staff Exhibit S-11.50.) Staff appreciates the Company's commitment to fulfilling the priorities of

[9] Prefiled direct testimony of Company witness Jessica R. Byrom, p. 19.

the EAAC and the Low-Income Energy Policy Board, but remains unconvinced that the LMI project will provide any avenues to tangibly do so. The information that this project proposes to distribute to customers already exists on the Company's website. This project will simply make that information easier to access, which could also be accomplished by making the Company's website easier to navigate via the monies allocated for the Company's website redesign. For all these reasons, Staff recommends full disallowance of the LMI Customer Support Enhancement project.

Q. Please provide a summary of your testimony.

A. My testimony provided reasoning for Staff's recommended disallowances in the amounts of $48,641 for the Click to Chat project, $195,494 for the Web Chat AI project, $1,490,685 for Mobile App Enhancements, and $2,140,754 for the Low Moderate Income Customer Support Enhancements projects.

Q. Does this conclude your testimony?

A. Yes.

MS. STIRLING: Staff calls to be filed the qualifications and direct testimony of Charles Putnam that consists of a cover sheet and nine pages of questions and answers. Mr. Putnam sponsored two exhibits associated with his direct testimony. These exhibits have been marked Exhibit S-14.1 and Exhibit S-14.2.

Staff moves to bind into the record the qualifications and direct testimony and to admit the associated exhibits of Charles Putnam.

JUDGE VARCHETTI: All right. Any objections to binding into the direct testimony of Mr. Putnam or his two associated exhibits?

I am hearing none, so the testimony is bound into the record and the exhibits admitted.

(Direct Testimony and Qualifications bound in)

**S T A T E OF M I C H I G A N**

**BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION**

*** * * ***

| | | |
|---|---|---|
| In the matter of the application of<br>**CONSUMERS ENERGY COMPANY**<br>for authority to increase its rates for the<br>distribution on natural gas and for other relief. | )<br>)<br>)<br>)<br>) | Case No. U-21806 |

**QUALIFICATIONS AND DIRECT TESTIMONY OF**

**CHARLES E. PUTNAM, CPA**

**MICHIGAN PUBLIC SERVICE COMMISSION**

**April 23, 2025**

**QUALIFICATIONS OF CHARLES E. PUTNAM, CPA**
**CASE NUMER U-21806**
**PART I**

Q. Please state your name and business address.

A. My name is Charles E. Putnam. My business address is 7109 W. Saginaw Highway, Lansing, MI 48917.

Q. By whom are you currently employed and in what capacity?

A. I am employed as an Auditing Specialist with the Michigan Public Service Commission (Commission or MPSC) in the Revenue Requirements Section of the Regulated Energy Division.

Q. How long have you been employed by the MPSC and what are your duties?

A. I joined the MPSC in 2006 as a Department Analyst in the Rates and Tariffs Section. My primary responsibilities involved cost of service studies for electric utilities. In April 2018, I joined the Revenue Requirements Section as an Auditing Specialist.

Q. Please describe your educational background and work experience.

A. I graduated from Davenport University, with distinction, in 2018 with a Master of Accountancy degree. I received a Bachelor of Science degree from Michigan State University in Physiology in 1981 and an Associate degree in Accounting from Lansing Community College in 1983. Prior to joining the MPSC I was a Corporate Tax Accountant for Dart Container Corporation from 1984 to 1992. I left Dart Container to take a Senior Accountant position with the City of Lansing. After leaving the City of Lansing in 1993, I served for 12 years as the Controller for Universal Map Enterprises. I am also an adjunct accounting professor with Lansing Community College and have over thirty years of teaching experience.

Q. Do you have any professional licenses?



VERITEXT LEGAL SOLUTIONS

**QUALIFICATIONS OF CHARLES E. PUTNAM, CPA**
**CASE NUMER U-21806**
**PART I**

A. Yes, I am a Certified Public Accountant, licensed by the State of Michigan.

Q. Have you previously presented testimony or been involved in proceedings before the Commission?

A. Yes, I have been involved in the following proceedings:

| Case Number | Company | Description |
|---|---|---|
| U-21448 | Alpena Power | Taxes |
| U-21045 | Alpena Power | Employee Benefit |
| U-21490 | Consumers Gas | Taxes |
| U-21308 | Consumers Gas | Taxes |
| U-21148 | Consumers Gas | Taxes |
| U-16855 | Consumers Gas | Cost of Service Study |
| U-16418 | Consumers Gas | Cost of Service Study |
| U-21389 | Consumers Energy | Taxes |
| U-21224 | Consumers Energy | Taxes |
| U-20963 | Consumers Energy | Taxes & Accounting Request |
| U-20889 | Consumers Energy | Securitization |
| U-20697 | Consumers Energy | Accounting Request |
| U-20309 | Consumers Energy | TCJA Calculation C |
| U-20286 | Consumers Energy | TCJA Credit B |
| U-20134 | Consumers Energy | Accounting Request |
| U-18322 | Consumers Energy | Cost of Service Study |
| U-17990 | Consumers Energy | Cost of Service Study |
| U-17735 | Consumers Energy | Cost of Service Study |



VERITEXT LEGAL SOLUTIONS

**QUALIFICATIONS OF CHARLES E. PUTNAM, CPA**
**CASE NUMER U-21806**
**PART I**

| | | | |
|---|---|---|---|
| 1 | U-17473 | Consumers Energy | Securitization |
| 2 | U-17688 | Consumers Energy | Cost of Service Study |
| 3 | U-17087 | Consumers Energy | Cost of Service Study |
| 4 | U-16794 | Consumers Energy | Cost of Service Study |
| 5 | U-16191 | Consumers Energy | Cost of Service Study |
| 6 | U-15645 | Consumers Energy | Cost of Service Study |
| 7 | U-15245 | Consumers Energy | Cost of Service Study |
| 8 | U-18255 | Detroit Edison | Cost of Service Study |
| 9 | U-18014 | Detroit Edison | Cost of Service Study |
| 10 | U-17767 | Detroit Edison | Cost of Service Study |
| 11 | U-17689 | Detroit Edison | Cost of Service Study |
| 12 | U-16472 | Detroit Edison | Cost of Service Study |
| 13 | U-15768 | Detroit Edison | Cost of Service Study |
| 14 | U-15244 | Detroit Edison | Cost of Service Study |
| 15 | U-21194 | Detroit Thermal | Transfer of Control |
| 16 | U-21248 | DTE-Gas | TCJA ADIT |
| 17 | U-21291 | DTE-Gas | Taxes and SADM |
| 18 | U-20940 | DTE-Gas | Accounting Request |
| 19 | U-20642 | DTE-Gas | Capital Usage Charge |
| 20 | U-20298 | DTE-Gas | TCJA Calculation C |
| 21 | U-20189 | DTE-Gas | TCJA Credit B |
| 22 | U-21534 | DTE-Electric | Taxes |
| 23 | U-21338 | DTE-Electric | Securitization |



VERITEXT LEGAL SOLUTIONS

**QUALIFICATIONS OF CHARLES E. PUTNAM, CPA**
**CASE NUMER U-21806**
**PART I**

| | | | |
|---|---|---|---|
| 1 | U-21307 | DTE-Electric | TRM Reconciliation |
| 2 | U-21297 | DTE-Electric | Taxes |
| 3 | U-21015 | DTE-Electric | Securitization |
| 4 | U-20987 | DTE-Electric | TRM Reconciliation |
| 5 | U-20836 | DTE-Electric | Taxes |
| 6 | U-20711 | DTE-Electric | TRM Reconciliation |
| 7 | U-20364 | DTE-Electric | TRM Reconciliation |
| 8 | U-20284 | DTE-Electric | TCJA Credit B |
| 9 | U-21461 | Indiana Michigan | Taxes |
| 10 | U-21377 | Indiana Michigan | CON: Production Tax Credits |
| 11 | U-20359 | Indiana Michigan | Accounting Request |
| 12 | U-17698 | Indiana Michigan | Cost of Service Study |
| 13 | U-21540 | Michigan Gas | Taxes |
| 14 | U-21366 | Michigan Gas | Taxes |
| 15 | U-20718 | Michigan Gas | Employee Benefits |
| 16 | U-20310 | Michigan Gas | TCJA Calculation C |
| 17 | U-20181 | Michigan Gas | TCJA Credit B |
| 18 | U-16426-R | Midwest | Cost of Service Study |
| 19 | U-21226 | Northern States Gas | Taxes |
| 20 | U-20312 | Northern States Gas | TCJA Calculation C |
| 21 | U-20186 | Northern States Gas | TCJA Credit B |
| 22 | U-21565 | Norther States Electric | Taxes |
| 23 | U-21097 | Northern States Electric | Employee Benefits |

**QUALIFICATIONS OF CHARLES E. PUTNAM, CPA**
**CASE NUMER U-21806**
**PART I**

| | | | |
|---|---|---|---|
| 1 | U-20313 | Northern States Electric | TCJA Calculation C |
| 2 | U-20185 | Northern States Electric | TCJA Credit B |
| 3 | U-18462 | Northern States Electric | Cost of Service Study |
| 4 | U-18383 | PA 341 and PA 342 | Cost of Service |
| 5 | U-20479 | SEMCO | ADIT and Cost Allocations |
| 6 | U-20311 | SEMCO | TCJA Calculation C |
| 7 | U-20182 | SEMCO | TCJA Credit B |
| 8 | U-14893 | SEMCO | Audit Taxes and Other Revenue |
| 9 | U-15413-R | Tri-County | Rate Design |
| 10 | U-15064-R | Tri-County | Audit/TIER/PSCR/Rate Design |
| 11 | U-14701-R | Tri-County | Audit/TIER/PSCR/Rate Design |
| 12 | U-14270-R | Tri-County | Audit/TIER/PSCR |
| 13 | U-21541 | Upper Michigan Energy | Taxes |
| 14 | U-20314 | Upper Michigan Energy | TCJA Calculation C |
| 15 | U-20183 | Upper Michigan Energy | TCJA Credit B |
| 16 | U-21555 | Upper Peninsula Power | Taxes |
| 17 | U-21286 | Upper Peninsula Power | Taxes |
| 18 | U-20995 | Upper Peninsula Power | Transfer of Control |
| 19 | U-20184 | Upper Peninsula Power | TCJA Credit B |
| 20 | U-17895 | Upper Peninsula Power | Cost of Service Study |
| 21 | U-17274 | Upper Peninsula Power | Cost of Service Study |
| 22 | U-16417 | Upper Peninsula Power | Cost of Service Study |
| 23 | U-16166 | Upper Peninsula Power | Rate Design |



VERITEXT LEGAL SOLUTIONS

**QUALIFICATIONS OF CHARLES E. PUTNAM, CPA**
**CASE NUMER U-21806**
**PART I**

| | | | |
|---|---|---|---|
| 1 | U-15988 | Upper Peninsula Power | Cost of Service Study |
| 2 | U-16830 | Wisconsin Electric | Cost of Service Study |
| 3 | U-15981 | Wisconsin Electric | Cost of Service Study |
| 4 | U-15500 | Wisconsin Electric | Cost of Service Study |
| 5 | U-15071 | Wisconsin Electric | Cost of Service Study |
| 6 | U-17669 | Wisconsin Public Service | Cost of Service Study |
| 7 | U-17710 | Xcel NSPW | Cost of Service Study |
| 8 | U-16475 | Xcel NSPW | Cost of Service Study |



VERITEXT LEGAL SOLUTIONS

**DIRECT TESTIMONY OF CHARLES E. PUTNAM, CPA**
**CASE NUMBER U-21806**
**PART II**

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to support Staff's proposed general tax expense projection for the 12-month test period ending October 31, 2026.

Q. Are you sponsoring any exhibits in this case?

A. Yes, I am sponsoring the following exhibits.

| Exhibit | Title |
|---|---|
| S-14.1 | Adjustment to Projected Sales Taxes |
| S-14.2 | Adjustment to Projected Other General Taxes |

Q. What is Company's projection for General Taxes for the projected 12-month period ending October 31, 2026?

A. Per Company Exhibit A-13 (HLR-36), Schedule C-1, Line 12, the Company projects $19,785,000 of General Taxes.

Q. What are the components of General Taxes?

A. The three components along with the Company's individual projections are: Payroll Tax - $14,666,000; MPSC Assessment Fee - $4,524,000; State Sales & Use Tax Absorbed by the Company - $594,000. (The total of these components differ by $1,000 when compared to the $19,785,000 total above due to rounding.)

Q. What adjustments are Staff proposing to make to the Company's projected General Taxes?

A. Staff proposed two adjustments. The first is a reduction in projected Payroll Tax of $60,000. The second is a reduction in Sales & Use Tax Absorbed by the Company of $400,000.

Q. Why is Staff proposing to reduce the Company's projection for Payroll Taxes?

A. The Company based their projected Payroll Tax on Historic 2023 expense adjusted for inflation through 12/31/2026. Staff used the Company's methodology, but stopped inflation at 10/31/2026, the end of the test-year. The result was a projected Payroll Tax Expense of $14,606,000, a $60,000 reduction.

Q. Does the Company agree with Staff's $60,000 proposed adjustment?

A. Yes. Per the Company's response to Staff's audit request (Exhibit S-14.1), the Company concludes that if the historical payroll tax amount is rounded to $13,540,000 the correct projected test year payroll tax expense would be the $14,606,000.

Q. Why is Staff proposing to reduce the Company's projection for Sales & Use Tax Absorbed by the Company?

A. The Company based their projected Sales & Use Tax Absorbed by the Company on Historic 2023 expense of $594,000 with no adjustments. Staff also uses Historic 2023 expense as a starting point but proposes to reduce that amount by $400,000 for amounts related to activity predating 2023. The result is a projected Sales & Use Tax Absorbed by the Company of $193,000. (There is a $1,000 difference due to rounding.)

Q. Does the Company agree with Staff's $400,000 proposed adjustment?

A. Yes. Per the Company's response to Staff's audit request (Exhibit S-14.2), the Company concludes that although paid in 2023, the audit settlement amount of $401,019 is a one-time expense that should be adjusted/removed from the calculation of projected other general taxes.

Q. What does Staff propose regarding the General taxes?

A. Staff proposes the Commission reduce the Company's General Tax projection by $460,000, from $19,785,000 down to $19,325,000.

Q. Does this conclude your testimony?

A. Yes, it does.

MS. STIRLING: Staff calls to be filed the qualifications and direct testimony of Elaina Braunschweig that consists of a cover sheet and 20 pages of questions and answers. Ms. Braunschweig sponsored two exhibits associated with her direct testimony. These exhibits have been marked Exhibit 15 and Exhibit 15. -- or I'm sorry, Exhibit S-15 and Exhibit S-15.1.

Staff moves to bind into the record the qualifications and to admit the direct testimony and associated exhibits of Elaina Braunschweig.

JUDGE VARCHETTI: Are there any objections to admitting the direct testimony of Ms. Braunschweig or either of her two associated exhibits?

I am hearing none, so the testimony is bound into the record and the exhibits are admitted.

(Direct Testimony and Qualifications bound in)

**S T A T E OF M I C H I G A N**

**BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION**

*** * * ***

| | | |
|---|---|---|
| **In the matter on the application of CONSUMERS ENERGY COMPANY for authority to increase its rates for the distribution of natural gas and for other relief.** | **)** | **Case No. U-21806** |

# QUALIFICATIONS AND DIRECT TESTIMONY OF

# ELAINA M. BRAUNSCHWEIG

# MICHIGAN PUBLIC SERVICE COMMISSION

**April 23, 2025**

**QUALIFICATIONS OF ELAINA M. BRAUNSCHWEIG**
**CASE NUMBER U-21806**
**PART I**

Q. Please state your name and business address.

A. My name is Elaina M. Braunschweig. Pronouns she/her. My business address is 7109 West Saginaw Hwy, Lansing, Michigan 48917.

Q. By whom are you employed and in what capacity?

A. I am employed by the Michigan Public Service Commission (MPSC or Commission) as a Departmental Analyst for the Rates and Tariff Section of the Regulated Energy Division.

Q. Please describe your educational background.

A. In 2018, I completed my Bachelor of Arts dual-major in Economics & Management and German with a minor in International Studies with honors from Albion College.

Q. What are your current responsibilities at the MPSC?

A. As an analyst, I participate in rate and tariff amendment cases under the direct supervision of the Rates and Tariff manager. I am also responsible for coordinating tariff-related *ex-parte* cases and the Rates and Tariff Section's connection to low-income energy assistance and affordability. To that end, in July 2021, I began co-leading the Affordability, Alignment, and Assistance subcommittee in the Commission's Energy Affordability and Accessibility Collaborative and continue that to-date.

Q. Have you attended any seminars or other training courses relating to your current role?

A. Yes. In August 2021, I participated in Michigan State University's Institute of Public Utilities Annual Regulatory Studies Program Fundamentals Course. In

**QUALIFICATIONS OF ELAINA M. BRAUNSCHWEIG**
**CASE NUMBER U-21806**
**PART I**

October 2021, I attended Michigan State University's Institute of Public Utilities Advanced Cost Allocation and Rate Design Course, and in February 2022, I attended EUCI's Electric Utility Pricing Trends in Cost Recovery Course.

Q. Have you previously presented testimony or participated in utility cases before the MPSC?

A. Yes , I have presented testimony or otherwise participated in the following cases:

| MPSC Case | Company | Description |
|---|---|---|
| U-20650 | Consumers Energy—Gas | Rate Design/Low-Income |
| U-20757 | Commission | Low-Income Covid Report |
| U-20907 | UMERC | Budget Billing Revisions |
| U-20929 | DTE Energy | PSP Pilot Proposal |
| U-21021 | Consumers Energy | PIPP Pilot Proposal |
| U-21148 | Consumers Energy—Gas | Rate Design/Low-Income |
| U-20836 | DTE Energy | Low-Income Credits |
| U-21286 | UPPCO | Low-Income Credits |
| U-21308 | Consumers Energy—Gas | Rate Design/Low-Income |
| U-21461 | Indiana Michigan Power | Rate Design/Low-Income |
| U-21490 | Consumers Energy—Gas | Low-Income Credits |
| U-21291 | DTE Gas | Low-Income Credits |
| U-21534 | DTE Energy | Low-Income Credits |
| U-21585 | Consumers Energy | Energy Affordability |



VERITEXT LEGAL SOLUTIONS

**DIRECT TESTIMONY OF ELAINA M. BRAUNSCHWEIG**
**CASE NUMBER U-21806**
**PART II**

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to present Staff's position on Consumers Energy Company's (the Company) Residential Income Assistance Credit (RIA) customer count projection.

Q. Are you sponsoring any exhibits in this proceeding?

A. Yes, I am sponsoring the following exhibits:

Exhibit No. S-15.0, titled "Consumers Energy's Audit Response"

Exhibit No. S-15.1, titled "Residential Income Assistance Credit Projection Support"

Q. Were these exhibits prepared by you or under your supervision?

A. Yes, they were.

Q. How is your testimony structured?

A. My testimony is structured as follows:

1. Company Residential Income Assistance Credit Projection
2. Staff's Residential Income Assistance Credit Projection and Revenue Impact
3. Summary

## 1. Company Residential Income Assistance Credit Projection

Q. In direct testimony, did the Company address its Residential Income Assistance (RIA) Credit enrollment projection proposal for the test year?

A. The Company did not address its projected RIA customer count in its direct testimony. It only mentioned that it expects 87,000 monthly income assistance program customers in the test year, based on a 12-month historical average.[1] The Company did not specify to which income assistance program or combination of programs it referred. On page 1 of Schedule F-3 (Company Exhibit No. A-16 [SAS-4]), the Company included recovery of 75,000 monthly RIA credit disbursements and 12,000 Low-Income Assistance Credit (LIAC) disbursements.[2]

Q. Does Staff support the Company's inclusion of 75,000 monthly RIA recipients in its proposed rate design?

A. Staff does not. The Company claimed on page 9 of witness Ahmed's testimony that its projection was "based on the 12-month average of the most recent history" but did not provide a calculation and the 12-month average enrollments for "most recent history." It is unclear to which 12 months the Company refers in its testimony.

Q. Did you discover a source or calculation of the purported 87,000 projected income assistance customers or 75,000 RIA disbursements?

[1] Direct testimony of Company witness Mustafa Ahmed, pp. 9-10. As set forth in Exhibit A-15 (MA-12), Schedule E-8.
[2] The Company did not increase the proposed LIAC enrollment figure from its last rate case: U-21490.

A. I did not. However, I can describe my process for attempting to find the supporting calculation. When looking into the source of the projected 75,000 monthly RIA recipients further, I explored Company witness Ahmed's referenced Exhibit A-15 (MA-12), Schedule E-8. What I found was the 87,000 projected income assistance customer counts with reverse-engineered projected monthly credit disbursements for November-25 to October-26. By reverse engineering, I mean these monthly projections were calculated by dividing projected total residential customers for each month by the monthly average and multiplying that number by the assumed 87,000. In short, the monthly projections (for customers and consumption) were calculated to be assumed proportional to the general residential class instead of being based on historical RIA enrollment actuals. Staff notes that the monthly RIA enrollments fluctuate much more than the residential class customer counts, so this method of projection is not reliable. Staff then looked into the source formula for the 87,000 on Schedule E-8 and discovered it to be in the "Inputs" tab of witness Ahmed's Exhibit A-5 (MA-1) to A-15 (MA-14) Microsoft Excel file. The origin of the 87,000 total income assistance customers in the input tab was a hard-coded value in cell C-19 labeled as "test year RIA," though it seemed to not just be RIA customers, but RIA and LIA added together, since the cell added 75,000 and 12,000. Data mislabeled in such a way makes it very difficult for Staff and other intervenors to do their due diligence in auditing the Company's case. Furthermore, the only explanation for the source of this hard-coded data in cell C-19 is "average of prior 12 months"—without indicating to which 12 months the Company refers and lacks any

calculation of the 75,000 and 12,000. Exploring further, in rows 872-881 of the same sheet in the same Excel file and inputs tab, there was a section labeled: "Residential Income Assistance Customer Count History" which I assume is credit disbursement data for November-July of an unknown and unlabeled year. The average for these months is 64,349, as calculated in cell Q-880 (however, that number is misleadingly calculated since the average includes zeros as data for August-October and presumably there were not zero credit disbursements for those months).

Q. What did Staff glean from the aforementioned exhibit?

A. Staff gleaned a murky picture of unexplained hard-coded values and an unsuccessful attempt to record or potentially calculate projected income-assistance recipient customer counts. Ultimately the Company did not use enrollment actuals from the Company's reported Attachment 46, nor it seems its partial year of data recorded in the inputs tab. Ultimately, I found no source nor explanation for the projected 75,000 RIA disbursements.

Q. Did Staff experience the same issues in the Company's last rate case, MPSC Case No. U-21490?

A. Yes, this is the same exact issue Staff encountered in the Company's last case[3]. The Company appears to have made no changes based on Staff's identification of these issues in the last case. The Commission should order the Company to work

[3] See *In re Consumers Energy Company Gas Rate Case,* MPSC Case No. U-21490, 2 TR 1873-1875, F#0192.

with Staff to improve its exhibits and testimony as it relates to this issue for its next filing, in an effort to improve the auditing process going forward.

Q. Did Staff request clarification in audit requests?

A. Yes, in part, Staff requested the calculation for and data inputs used to calculate the proposed 87,000 "RIA" customer count projection explanation for all components of the Company's projection, why the Company based its projection on the 12-month average of the most recent history, and generally explaining the discrepancies between the purported 87,000 RIA customers when there are references to 75,000 monthly RIA customers and 12,000 LIA customers in other data input fields in the Company's filing.[4]

Q. Please summarize the Company's responses detailed in Exhibit No. S-15.0.

A. In short, the Company clarified that the 87,000 monthly "RIA" customer count projection was actually RIA and LIA recipients combined (75,000 monthly RIA recipients and 12,000 monthly LIA recipients) and the projection was based on the most recent 12-months of data, which was not provided in its initial filing.[5] The Company stated that it used this methodology for its projection because it was the approved methodology in the July 31, 2017 Order in Case No. U-18124 (page 59). In the second round of audit requests, Staff requested some clarification on why the data[6] the Company used for its projection does not match

[4] Exhibit No. S-15.0
[5] Exhibit No. S-15.0 pp. 1-2
[6] Exhibit No. S-15.0 p. 2

the RIA credit disbursement data provided in Part III Attachment 46.[7] The Company's answer, in part, was as follows:

> The data provided in U21806-SA-CE-337_Sherwani_Attachment_1 are customers that received the IA credit, whereas Part III attachment 46 are customers enrolled in the IA program profit centers at a point in time. Customers that are enrolled/unenrolled in the IA program (based on their qualification) at a point in time may or may not be enrolled/unenrolled into the correct profit center. Therefore, RIA customer counts provided in U21806-SA-CE-337_Sherwani_Attachment_1 is most accurate since it totals customers that receive the credit.

Q. Did Staff identify an issue with the Company's response?

A. Yes. Company witness Ahmed's answer alludes to customers' enrollment in the RIA credit, but enrollment does not necessarily equal credit disbursements. He states that "U21806-SA-CE-337_Sherwani_Attachment_1 is most accurate since it totals customers that receive the credit." Staff is concerned that Attachment 46 is supposed to have been providing customer count data for the RIA and LIAC programs for years. Most notably was in the Company's last rate case, U-21490, when Staff asked audit questions about the credit, but this issue of data credibility was never raised. Even when the Company raised this issue of data inconsistency in the current case, witness Ahmed did not even suggest that the Attachment 46 data would need to be updated for accuracy, nor did he suggest that the Company has been reporting incorrectly for years. This calls into question the accuracy of all related data, which is something that should be resolved outside the rate case to ensure that the Company's claim is not just another misunderstanding.

[7] Exhibit No. S-15.0 p. 6

## 2. Staff Residential Income Assistance Credit Projection

Q. What are the main qualifiers for RIA recipients that impact the RIA credit projection?

A. The main identifiers for RIA eligibility and thus automatic enrollment into this program are: the Michigan Department of Health and Human Services (MDHHS), the Michigan Department of Treasury, or Michigan Energy Assistance Program (MEAP) grantees notifying utilities of a customer receiving a State Emergency Relief (SER) payment, a Home Heating Credit (HHC) energy draft, or MEAP assistance payment, respectively, that would get applied to their account. These programs require the utilities to apply a payment to the customer's account on the program manager's behalf, which identify the customer as RIA-qualified, as per MCL 460.11(2) and defined in MCL 460.10t(6)(b), and results in automatic enrollment in the RIA credit.

Q. What impacts RIA credit enrollment fluctuations?

A. SER and HHC are funded by the Low-Income Home Energy Assistance Program (LIHEAP); MDHHS could also allocate LIHEAP SER dollars to other programs such as Energy Direct one-time payments (however, this program seems to have come to an end). Since all but MEAP are funded by federal LIHEAP dollars, the main determinant of RIA enrollment fluctuation has been average LIHEAP funding levels.

Q. What are the historical LIHEAP funding levels for Michigan?

A.

| Historical Michigan LIHEAP Funding | | |
|---|---|---|
| Fiscal Year | Funding Level | Monthly RIA Enrollments (fiscal years)[8] |
| October 1, 2019-September 30, 2020 | $ 197,960,572.00 | 65,229 |
| October 1, 2020-September 30, 2021 | $ 435,542,243.25 | 60,392 |
| October 1, 2021-September 30, 2022 | $ 166,875,852.32 | 58,274 |
| October 1, 2022-September 30, 2023 | $ 269,598,865.00 | 71,983 |
| October 1, 2023-September 30, 2024 | $ 180,456,685[9] | 72,346 |
| October 1, 2024-September 30, 2025 | $ 165,572,854 | |
| Company Test Year projection | | 75,000 |

Q. What are the historical funding levels for MEAP?

A. MEAP was established through Public Act 615 of 2012 and was funded at $50,000,000 annually until October 1, 2025, per Public Act 95 of 2013. In 2024, revisions to the MEAP legislation were passed by the Michigan Legislature and subsequently signed into law and now, in the upcoming fiscal year, there is no longer a cap on the Low Income Energy Assistance Fund (LIEAF) amount and the LIEAF surcharge is able to increase from $0.88/electric retail billing meter/month[10] to $1.25/electric retail billing meter/month starting in the September billing month of 2025.[11] At the time of this filing, the Commission has not approved a LIEAF funding factor nor stated the corresponding amount of funding the factor is projected to collect in the upcoming MEAP program year.

[8] Exhibit No. S-17.1
[9] https://acf.gov/sites/default/files/documents/ocs/COMM_LIHEAP_ReallotDCLAtt1Table_StatesTerrs_FY2023toFY2024.pdf
[10] This was the surcharge for the MEAP program year 2024, but the legislation at the time dictated that the surcharge could not exceed $1 per meter per month nor collect more than $50,000,000
[11] MCL 460.9t(8)

Q. What impact could this have on Consumers Energy's gas RIA enrollments?

A. That is uncertain at this time. Staff has identified some factors that could lead to an RIA credit disbursement increase, decrease, or stagnation—all of which are uncertain. Staff will list its views of potential impacts below.

Q. What could lead to potential increases in RIA enrollment as a result of the newly amended MEAP legislation?

A. Potential RIA enrollment increases could be caused by:

The increase in the LIEAF funding cap[12] could lead to an increase in customers able to be served.

Additionally, SER is no longer required as a precursor to receiving MEAP under the legislative changes,[13] which could lead to an increase in MEAP recipients and therefore RIA enrollment due to stricter eligibility criteria on SER than the revised MEAP legislation.[14] However, as experienced/observed with previous program changes, it can take up to 3 years for customers to fully learn of rule changes and adjust accordingly.

Q. What could lead to potential decreases in RIA enrollment as a result of the newly amended MEAP legislation?

A. Potential RIA enrollment decreases could be caused by:

[12] MCL 460.9t(8)
[13] This is due to a mixture of policy and law changes. The legislation now references both crisis and energy insecurity instead of inferring that MEAP was a crisis program, like SER (MCL 400.1233). Also, if SER eligibility is misaligned with MEAP in MCL 400.1232(e), it likely couldn't be required.
[14] In addition to the income eligibility criteria of ≤150% of the Federal Poverty Level, SER also counts unreceived child support payments as income and has cash asset limits, to name a couple of criteria.

One, with MEAP income eligibility increasing to 60% of state median income (SMI), utilities can no longer assume a MEAP recipient is eligible at 150% FPL or lower. Those who are categorically eligible, having not received SER, will have an unknown income threshold under MEAP, and thus an unknown eligibility for RIA under MCL 460.10t(6)(b).

Two, LIEAF is collected through a surcharge on *electric* retail billing meters.[15] A Consumers Gas customer that has electric service through a utility that opts-out of MEAP will no longer have access to MEAP funds and services like it used to under previous laws[16] and policies but will have to seek assistance from the energy assistance programs required to be provided by their electric utility if the utility opts-out of MEAP.[17] This is most impactful on RIA enrollment for customers who were in 2-year affordable payment plans and received LIA during that time, despite not recertifying eligibility in year two of the plan. So, under this legislation change, a customer with an opt-out electric utility is not eligible to receive MEAP and if they don't recertify by SER or other means, they would no longer automatically receive credits in the second year of an APP, which could lead to a decrease in RIA enrollments if they aren't timely with their income recertification.[18]

[15] 460.9t(15)(b)
[16] MCL 400.1232(e)
[17] MCL 460.9t(10)
[18] Evidence from the DTE percentage of income payment plan pilot report (MPSC Case No. U-20929, 1/29/2025 DTE Energy PSP Pilot Report, p. 58, figure 24) suggests that customers are not timely at recertifying their income eligibility for assistance programs even with reminders. There's been no evidence to suggest that Consumers Energy has provided notification to RIA and LIA recipients of their credit ending and a reminder to recertify income. In fact, Staff has received complaints from customers calling in to the MPSC call center that Consumers Energy provides no notification to customers that their credit is ending and that they would need to reverify their income.

Q. What could lead to potential stagnation in RIA enrollment as a result of the newly amended MEAP legislation?

A. Potential RIA enrollment stagnation could be caused by:

The increase in MEAP eligibility from ≤150% FPL up to ≤60% SMI[19] is complicated as it relates to the RIA enrollment because RIA eligibility is set at ≤150% FPL (or receipt of Medicaid, SER, or SNAP).[20] Due to limited funding and increasing need, it is possible that MDHHS will not increase its eligibility to ≤60% SMI this year. If so, there's a chance that only MEAP recipients ≤150% of the FPL could be enrolled in RIA. If MEAP grantees do not notify the Company that a customer is ≤150% of the FPL, it raises the question if the Company can enroll them in the RIA. MDHHS has yet to publicly announce its decision on if it will align its eligibility criteria with MEAP.

Another factor that could lead to stagnant RIA disbursements is that the increase in the LIEAF cap[21] could lead to an increase in customers served above 150% of the FPL now that eligibility has increased from ≤150% FPL up to ≤60% SMI and RIA eligibility is restricted to ≤150% FPL.

Finally, as alluded to earlier, LIHEAP legislation allows for SER to increase eligibility up to 60% SMI, but if MDHHS does not choose to institute this change and SER and MEAP eligibility are misaligned, it will limit the increase in eligible customers as well as ease of using SER as a categorically eligible program for MEAP and thus RIA. But even if SER income eligibility were raised, likely

[19] MCL 400.1232(e)
[20] MCL 460.10t(6)(b)
[21] MCL 460.9t(8)

MDHHS would not be able to serve additional customers, since LIHEAP funding has not increased for the State of Michigan in a way that would accommodate the additional eligible customers. If funding does not increase proportional to eligibility expansion, it's unlikely that more customers will be enrolled in SER assistance unless they're granted significantly less bill assistance when they seek it.

Q. What is the takeaway from the foregoing discussion about MEAP legislation changes impacts on RIA credit disbursements?

A. The takeaway is that changes in MEAP eligibility may not allow more customers to receive RIA and requiring a customer's electric provider to opt-in to the LIEAF in order for the customer to receive heating assistance (natural gas, in this case), may even decrease Consumers Energy natural gas customers' access to MEAP services.

Q. What are the average monthly RIA enrollments for the past five calendar years?

A. As shown in Exhibit No. S-15.1,

| Calendar Year | Monthly Average RIA Enrollments |
|---|---|
| 2020 | 64,073 |
| 2021 | 56,532 |
| 2022 | 63,022 |
| 2023 | 73,819 |
| 2024 | 69,506 |

As is shown, in the absence of all the changing factors in the energy assistance landscape listed previously in this testimony, average monthly RIA enrollments are trending downward. Something to note about calendar year 2024 enrollment data versus fiscal year data is that enrollments in the latter part of 2024 were significantly lower than the corresponding months in 2023, which pulls the calendar year monthly average down versus fiscal year 2024. The monthly breakdown is shown in Exhibit No. S-15.1.

Q. Please further explain how average LIHEAP funding levels have been the main determinant of RIA enrollment fluctuation.

A. I specify average funding levels because year-to-year LIHEAP funding levels change and how MDHHS allocates LIHEAP dollars and how much assistance each customer receives will influence the number of RIA-eligible LIHEAP recipients. Plainly stated, some years, MDHHS determines a maximum amount to award customers and that can lead to fewer customers receiving assistance. If the amount provided to each customer is less in a given year, then more customers are awarded assistance. This will create trends in the RIA enrollment, but RIA enrollment will not necessarily increase proportional to the LIHEAP funding level, especially if the United States Congress passes bills that allocate additional LIHEAP funding to each state that may not be required to be spent within the fiscal year like normal LIHEAP allocations are, as it has in the past. This has not occurred in recent years, but fiscal years 2021[22] and 2023[23] included additional

[22] See information on the American Rescue Plan.
[23] See information on the Inflation Reduction Act and the linked White House press release.

Covid-related funding that has since been exhausted that had these differing rules for when it was spent. The increase in RIA enrollment from 2021 to 2022, however, was partly due to an increase in SER as well as four rounds of LIHEAP Direct Support (now called Energy Direct) payments in 2022 and 2023.[24] The reason LIHEAP has been the main determinant of RIA disbursements and MEAP has had little to no impact on RIA enrollment is because, up until the 2024 MEAP legislation change, SER (funded by LIHEAP) has been a prerequisite to receiving MEAP.

Q. Is the elevated RIA enrollment from Covid-19 related funding and LIHEAP Energy Direct in 2022-2023 expected to carry over into the test year?

A. No, it is not. Since RIA customer eligibility is re-verified annually,[25] the higher number of recipients the Company reported in 2022 and 2023 should not be automatically rolled over into the test year, meaning RIA enrollments should slowly decrease in the absence of the elevated Covid-related funding, as is shown in the recent enrollment figures from 2024—especially since in fiscal year 2024, decreased funding led to MDHHS running out of funds, suspending assistance more than three months early, and not being able to serve as many customers as usual.[26]

[24] Staff's use of "Covid-related" refers to the federal funding increases aimed at lessening the after-effects of the Covid-19 pandemic, such as the American Rescue Plan and Inflation Reduction Act.
[25] See Consumers Energy's natural gas rate book, third revised Sheet No. D-10.00 under "Income Assistance Provision", which states in part: "The total household income is verified when the customer has provided proof that they have received, or are currently participating in, one or more of the following within the past 12 months…"
[26] https://www.michigan.gov/mdhhs/-/media/Project/Websites/mdhhs/Inside-MDHHS/Reports-and-Statistics---Human-Services/Trend-Reports/GT-038-Trend_SER_Energy_Detail.pdf?rev=918008995a03478eb64708182e28b5b9&hash=37EA60B6BCD2C560E473C764CA251AC2

Q. Are there any concerns with LIHEAP funding being eliminated in the test year?

A. Yes. As of writing this testimony, the U.S. Secretary of Health and Human Services fired all federal workers that administer LIHEAP as well as the office that determines the federal poverty guidelines that set eligibility for LIHEAP and other federal assistance programs.[27]

Q. What relevant RIA proposal has been accepted by the Commission in recent rate cases?

A. In Consumers Electric's rate case, MPSC Case No. U-21585, the Commission accepted Staff's method of projecting the RIA customer count, which is utilizing the three-year historical average of credit disbursements (MPSC Case No. U-21585, 3/21/2025 Order, p. 268).

## 2. Staff's Residential Income Assistance Credit Projection and Revenue Impact

Q. What does Staff propose for the RIA disbursement projection?

A. Given the multitude of factors and uncertainties that could impact RIA credit disbursements, as outlined previously in this testimony, it is clear that this is a complicated issue that could lead to a multitude of outcomes. It is nearly impossible to know what will occur in the test year, which is why it is most appropriate to base projections on 3-year historical averages (consistent with the last approved Commission order) and approve regulatory assets and liabilities to

[27] https://apnews.com/article/heating-assistance-hhs-layoffs-kennedy-trump-91e466c458ac804b098be00867a92106
https://www.cbsnews.com/news/trump-hhs-poverty-levels-medicaid-benefits/

account for any differences in enrollment projections versus actuals to ensure that customers receive the assistance ratepayers are paying for. Staff proposes using a 3-year historical calendar year average monthly RIA credit disbursement totaling 68,782. This adjustment includes the 2024 numbers offered by Company witness Ahmed in his audit response that were reported consistent with Part III data. However, if the Commission chooses to accept the data that witness Ahmed provided that is inconsistent with Part III data, the Commission should incorporate that into Staff's method of using a three-year historical average projection instead of accepting the Company's 12-month average projection.[28] Staff recognizes the increase in Covid-related LIHEAP funding and MDHHS LIHEAP allocations led to an increase in RIA credit disbursement and that there are many factors that could increase or decrease the number of customers automatically enrolled in the RIA credit. However, with the LIHEAP funding reverting back to pre-Covid-19 funding levels, the chance that LIHEAP funding could be eliminated entirely like its federal staff, and the likelihood that the expanded MEAP income eligibility couldn't apply to RIA recipients, Staff's projection is more reasonable and supported. By including the recent enrollment spikes in Staff's projection, Staff is acknowledging that LIHEAP and MEAP allocations, and thus RIA credit disbursement, increases have occurred in past and could impact the projected test year.

Q. Where did Staff incorporate its monthly customer count adjustment in its case?

[28] Data found in Exhibit No. S-15.0, p.6, SA-CE-362

A. Staff witness Nancy Rademacher updated Staff's RIA credit count on page one of Exhibit S-6, Schedule F-3.

Q. What impact does overestimating customer counts or under-enrolling customers in the credits have on ratepayers?

A. Overestimating customer counts allows the Company to retain the excess unused dollars recovered by ratepayers, absent deferred accounting for differences between actuals above or below the projection used to set rates. Even with deferred accounting, it is appropriate to utilize the most accurate and reliable forecast to set rates. Moreover, if RIA enrollments for the test year exceed Staff's projection, Staff expects Consumers Energy to continue enrolling all eligible customers in the RIA credit and choosing customers from the RIA credit to receive the LIAC until the Company reaches the approved cap on LIAC enrollment. The RIA credit is not "funded" at a certain level but utilizes a projection of the customers expected to receive it in the test year for ratemaking purposes. The credit's availability is not contingent on anything but customers meeting the requirements.

Q. What revenue adjustment is Staff proposing based on Staff's proposed adjustment to the RIA credit disbursement projection?

A. The revenue impact of Staff's adjustment to the annual projected RIA credit disbursement totals an increase of $1,119,240 to present revenue. Support for this calculation can be found in Exhibit No. S-15.1.

## 3. Summary

Q. Please summarize your positions and recommendations in your direct testimony.

A. Staff proposes a projected monthly RIA credit disbursement of 68,782 for incorporation in the rate design model (Exhibit S-6, Schedule F-3), for which the corresponding upward adjustment to present revenue would be $1,119,240. Staff also proposes implementing a regulatory asset and liability to account for the multitude of unknowns that could impact RIA enrollments in the test year and to ensure all dollars meant to assist customers are returned to customers.

Q. Does this conclude your testimony?

A. Yes, it does.

MS. STIRLING: Staff calls to be filed the qualifications and direct testimony of Kevin Spence that consists of a cover sheet and 22 pages of questions and answers. Mr. Spence sponsored three exhibits associated with his direct testimony. These exhibits have been marked Exhibit S-16.1, Exhibit S-16.2, and Exhibit S-16.3.

Staff moves to bind into the record the qualifications and direct testimony and to admit the associated exhibits of Kevin Spence.

JUDGE VARCHETTI: Are there any objections to binding in the direct testimony of Mr. Spence or admitting any of his three associated exhibits?

I am hearing none, so the testimony is bound into the record and the exhibits are admitted.

(Direct Testimony and Qualifications bound in)

**S T A T E OF M I C H I G A N**

**BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION**

*** * * ***

| | | |
|---|---|---|
| **In the matter of the application of CONSUMERS ENERGY COMPANY for authority to increase its rates for the distribution of natural gas and for other relief.** | **)** | **Case No. U-21806** |

# QUALIFICATIONS AND DIRECT TESTIMONY OF

# KEVIN P. SPENCE

# MICHIGAN PUBLIC SERVICE COMMISSION

**April 23, 2025**

**QUALIFICATIONS OF KEVIN P. SPENCE**
**CASE NUMBER U-21806**
**PART I**

Q. Please state your name, business address, and occupation.

A. My name is Kevin P. Spence, and my business address is 7109 West Saginaw Highway, Lansing, Michigan 48917. I am employed by the Michigan Public Service Commission (MPSC or the Commission) as a Public Utilities Engineering Specialist (PUES) in the Gas Safety and Operations Division (GSOD); my working title, per my position description, is Underground Natural Gas Storage (UNGS) Specialist.

Q. On whose behalf are you testifying?

A. I am testifying on behalf of the MPSC Staff (Staff).

Q. What is your educational background?

A. I earned a Bachelor of Science degree in Geological Engineering, with a Minor in Mining, from Michigan Technological University in December of 2013.

Q. Please briefly describe your professional work experience prior to your employment with the MPSC.

A. Prior to my employment with the MPSC, I was employed in the upstream oil and gas production industry by Dart Oil and Gas Corporation (Dart) as an Engineer in the Mason, Michigan office. During my employment with Dart, I was responsible for the following:

- The review and performance analysis of the company's oil and gas production wells, waterflood injection wells, and brine disposal wells;
- The review of operational expenses;
- The review of capital expenditure requirements and economic feasibility studies of re-work and re-completion projects;

- The geologic and reserve analysis of behind-pipe hydrocarbon production potential;
- The environmental assessment and area monitoring of chloride remediation activities;
- The production string optimization and production efficiency;
- The economic viability review and analysis of production asset acquisitions;
- The development, completion, and submittal of mid-year and year-end company reserve reports; and
- The representation of the company during drilling, open-hole logging operations, and completions of newly permitted hydrocarbon production wells and re-work operations.

Q. During your employment with Dart, did you participate in any professional meetings, seminars, or training outside of your direct work-related duties and responsibilities?

A. Yes. During my employment with Dart, I attended:

- Multiple Michigan Oil and Gas Association (MOGA) meetings;
- Core Workshop seminars hosted by the Michigan Geological Repository for Research and Education Geosciences Department and Western Michigan University, part of the Michigan Geological Survey and MOGA;
- Open-hole Log Analysis and LMKR Geographix training hosted by Boog Exploration and Consulting; and

- Hydrogen Sulfide Safety Training hosted by Scott E. Carroll Safety Training & Consulting.

Q. When did you begin your employment with the MPSC?

A. In November of 2017, I was offered, and accepted, a position as a Public Utilities Engineer (PUE) in the then Gas Operations Section of the Operations and Wholesale Markets Division, now GSOD, with the MPSC.

Q. What were your duties and responsibilities as a PUE within the Gas Operations Section of the MPSC?

A. My responsibilities as a PUE within the Gas Operations Section of the MPSC included, but was not limited to:

- Engineering duties related to the Commission's regulation of natural gas well production and proration;
- UNGS;
- Gas pipeline safety;
- Compliance with the Commission's Technical Standards for Gas Service (Gas Tech. Standards), including review of gas utilities' meter testing programs;
- Serving as case coordinator in Public Act 9 of 1929 (Act 9) siting for natural gas pipelines, Public Act 16 of 1929 (Act 16) siting for liquid and carbon dioxide pipelines, Public Act 69 of 1929 (Act 69) for Certificates of Public Convenience and Necessity (CPCN), and other Gas Operations Section cases;

- Providing technical assistance and support in the preparation of data and information pertaining to docketed natural gas related cases; and
- Various other utility functions, including review of gas utilities' customer attachment programs and complaints or inquiries related to those programs.

Additionally, I had been accompanying the Pipeline and Hazardous Materials Safety Administration (PHMSA) during the inspection of Michigan's intrastate and interstate UNGS fields beginning in 2018.

Q. When did you receive the promotion from PUE to PUES in the Gas Operations Section of the MPSC?

A. I was promoted to PUES in the Gas Operations Section, with the working title of UNGS Specialist, in September of 2021.

Q. What are your current duties and responsibilities as a UNGS Specialist within the GSOD of the MPSC?

A. In 2021, the MPSC, in cooperation with the Department of Environment, Great Lakes, and Energy's (EGLE) then Oil, Gas, and Minerals Division, now Geologic Resources Management Division (GRMD), was approved to be PHMSA's partner and granted certification[1] to conduct the inspections, and enforcement, of Michigan's intrastate UNGS fields. At this time, I was promoted to UNGS

[1] Beginning in 2024, PHMSA changed the MPSC/EGLE joint UNGS Partnership in the UNGS Program from a 60105 Certification to a 60106 Agreement due to insufficient penalties the MPSC was authorized to assess. Due to the program change, the MPSC/EGLE joint UNGS Partnership no longer had authorization for enforcement in the UNGS Program. On October 8, 2024, Senate Bill 366, which brought the MPSC's penalty authorization up to PHMSA's UNGS Program standards, was signed by the Governor and passed as Public Act 131 of 2024 (Act 131). Subsequently, on October 8, 2024, PHMSA reinstated the MPSC/EGLE joint UNGS Partnership's 60105 Certification status.

Specialist. In addition to my duties and responsibilities as a PUE within the Gas Operations Section of the MPSC as previously noted, as a UNGS Specialist, I am responsible for:

- Conducting inspections of all Michigan intrastate UNGS operators' procedures, records, and field assets related to the UNGS Facilities regulations (49 CFR 192.12) and the American Petroleum Institute (API) Recommended Practice (RP) 1170, Design and Operation of Solution-mined Salt Caverns Used for Natural Gas Storage, and API RP 1171, Functional Integrity of Natural Gas Storage in Depleted Hydrocarbon Reservoirs and Aquifer Reservoirs, industry standards, incorporated by reference;
- Coordinating all inspections of Michigan intrastate UNGS facilities with EGLE's OGMD;
- Participating in all Michigan interstate gas storage operator inspections conducted by the Federal Department of Transportation's (DOT) PHMSA;
- Tracking and conducting follow-up inspections statewide of incidents and Safety Related Conditions (SRCs) involving issues related to UNGS facilities; and
- Assist the Commission and OGMD management with the maintenance of the GSOD's MPSC Pipeline Safety Database to accommodate gas storage inspections, maintaining inspection and program data in PHMSA's database, and administration of the PHMSA Grant associated with the UNGS program.

Q. Have you provided a leadership role in Commission activities?

A. Yes. In February of 2019, I was selected as a workgroup chair to lead the Commission's response on the natural gas portion of the Michigan Statewide Energy Assessment (SEA) report. As a follow-up to the recommendations provided in the final SEA report issued in September of 2019, I was selected as the project lead for two collaborative workgroups; one to investigate options for expanding mutual aid agreements and contingency planning between Michigan's natural gas utilities[2]; and the other to explore potential updates to the utility curtailment tariffs[3].

Q. During your employment with the MSPC, have you participated in any professional meetings, seminars, workgroups, or training outside of your direct work-related duties and responsibilities?

A. Yes. I have attended:

- Multiple Oil and Gas Advisory Committee (OGAC) meetings;
- Pipeline safety training hosted by Flour and HDR Inc.;
- Asbestos awareness training hosted by Consumers Energy Company;
- Incident Investigation, Root Cause Analysis Training, and MORT Certification hosted by Conger & Elsea;
- The 13th Annual API Cybersecurity Conference for the Oil & Natural Gas Industry;

[2] MPSC Case No. U-20631
[3] MPSC Case No. U-20632

- The 2019 Pipeline Safety Conference hosted by the Gas Operations Section of the MPSC;
- The 2024 Pipeline Safety Conference hosted by the GSOD of the MPSC;
- The 2023 Michigan Energy Providers Conference;
- The Fundamentals of Hydrogen course hosted by GTI Energy;
- The API Task Group to revise Version 2 of the Pipeline Supervisory Control and Data Acquisition (SCADA) Security Standard 1164 to Third Edition; and
- The Fugitive Emissions of Methane and VOCs from Underground Natural Gas or refined Production Pipelines Workgroup led by EGLE's Air Quality Division (AQD).

Q. Are you a member in good standing with any professional organizations?

A. Yes. I have been a member in good standing with the Society of Petroleum Engineers since September of 2013.

Q. Have you participated in any other cases before the MPSC prior to this current proceeding?

A. Yes. I have participated, in various capacities, in the following cases before the MPSC:

| **Case No.** | **Case Description** |
|---|---|
| U-18424 | Consumers Energy Company gas rate case |
| U-18999 | DTE Gas Company gas rate case |
| U-20062 | DTE Gas Company Act 69 case |
| U-20089 | Consumers Energy Company and CMS Generation Michigan Power |

**QUALIFICATIONS OF KEVIN P. SPENCE**
**CASE NUMBER U-21806**
**PART I**

| | | |
|---|---|---|
| | | LLC Act 9 case |
| | U-20143 | Consumers Energy Company Act 69 case |
| | U-20198 | Zeeland Farm Services Ithaca, LLC Act 9 case |
| | U-20280 | DTE Gas Company C8 tariff case |
| | U-20322 | Consumers Energy Company gas rate case |
| | U-20346 | DTE Gas Company Technical Standards for Gas Service waiver case |
| | U-20351 | Northern States Power Company C8 tariff case |
| | U-20464 | Michigan Public Service Commission Statewide Energy Assessment |
| | U-20479 | SEMCO Energy Gas Company gas rate case |
| | U-20517 | Michigan Gas Utilities Corporation Technical Standards for Gas Service waiver case |
| | U-20568 | Consumers Energy Company Act 9 case |
| | U-20608 | Michigan Public Service Commission Technical Standards for Gas Service revision case |
| | U-20618 | Consumers Energy Company Act 9 case |
| | U-20626 | Consumers Energy Company Technical Standards for Gas Service waiver case |
| | U-20631 | Michigan Public Service Commission Natural Gas Mutual Aid & Contingency Planning Workgroup |
| | U-20632 | Michigan Public Service Commission Natural Gas Curtailment Procedures Workgroup |
| | U-20634 | Michigan Public Service Commission revisions to prescribed fees for Act 9 & Act 16 cases |

**QUALIFICATIONS OF KEVIN P. SPENCE**
**CASE NUMBER U-21806**
**PART I**

| | | |
|---|---|---|
| 1 | U-20637 | Consumers Energy Company Act 9 case |
| 2 | U-20640 | DTE Gas Company Act 9 case |
| 3 | U-20641 | DTE Gas Company Act 9 case |
| 4 | U-20718 | Michigan Gas Utilities Corporation gas rate case |
| 5 | U-20738 | SEMCO Energy Gas Company Act 9 case |
| 6 | U-20745 | Bluewater Gas Storage LLC inspection schedule application |
| 7 | U-20752 | Michigan Gas Utilities Corporation Act 69 case |
| 8 | U-20763 | Enbridge Energy, Limited Partnership Act 16 case |
| 9 | U-20798 | Consumers Energy Company Act 9 case |
| 10 | U-20828 | Consumers Energy Company waiver application |
| 11 | U-20842 | Consumers Energy Company Act 9 case |
| 12 | U-20853 | Michigan Gas Utilities Corporation Act 9 case |
| 13 | U-20894 | DTE Michigan Lateral Company Act 9 case |
| 14 | U-20940 | DTE Gas Company gas rate case |
| 15 | U-20945 | Consumers Energy Company Technical Standards for Gas Service |
| 16 | | waiver case |
| 17 | U-20975 | DTE Gas Company Technical Standards for Gas Service waiver case |
| 18 | U-20983 | Michigan Gas Utilities Corporation Act 9 case |
| 19 | U-20993 | Saginaw Bay Pipeline Company transportation rates case |
| 20 | U-20994 | DTE Michigan Gathering Company Delivery Point Agreement case |
| 21 | U-21024 | DTE Gas Company Technical Standards for Gas Service waiver case |
| 22 | U-21027 | SEMCO Energy Gas Company Technical Standards for Gas Service |
| 23 | | waiver case |

**QUALIFICATIONS OF KEVIN P. SPENCE**
**CASE NUMBER U-21806**
**PART I**

| | | |
|---|---|---|
| 1 | U-21086 | Consumers Energy Company revision of natural gas curtailment tariff |
| 2 | | provisions case |
| 3 | U-21091 | Lambda Gathering, LLC Act 9 case |
| 4 | U-21093 | Wallick-Hendy Development Company, LLC Declaratory Ruling case |
| 5 | U-21098 | Brightmark Castor RNG LLC Act 9 case |
| 6 | U-21114 | Michigan Gas Utilities Corporation Technical Standards for Gas |
| 7 | | Service waiver case |
| 8 | U-21119 | DTE Gas Company Act 9 case |
| 9 | U-21162 | DTE Gas Company Act 69 case |
| 10 | U-21167 | Presque Isle Electric & Gas Co-op Act 69 case |
| 11 | U-21175 | DTE Gas Company Act 69 case |
| 12 | U-21179 | Consumers Energy Company Act 9 case |
| 13 | U-21181 | SEMCO Energy Gas Company Act 69 case |
| 14 | U-21182 | DTE Gas Company Act 69 case |
| 15 | U-21187 | Marysville Hydrocarbons LLC Act 16 case |
| 16 | U-21188 | DTE Gas Company Act 69 case |
| 17 | U-21190 | NGL Energy Supply Terminal, LLC Act 16 case |
| 18 | U-21213 | Consumers Energy Company Act 9 case |
| 19 | U-21226 | Northern States Power Company rate case |
| 20 | U-21289 | De Saegher Energy LLC Act 9 case |
| 21 | U-21291 | DTE Gas Company gas rate case |
| 22 | U-21292 | Michigan Gas Utilities Corporation Act 9 case |
| 23 | U-21301 | Citizens Gas Fuel Company Act 9 case |



VERITEXT LEGAL SOLUTIONS

**QUALIFICATIONS OF KEVIN P. SPENCE**
**CASE NUMBER U-21806**
**PART I**

| | | |
|---|---|---|
| 1 | U-21308 | Consumers Energy Company gas rate case |
| 2 | U-21333 | Consumers Energy Company Act 69 case |
| 3 | U-21335 | Lambda Energy Resources LLC Act 9 case |
| 4 | U-21341 | Consumers Energy Company Technical Standards for Gas Service |
| 5 | | waiver case |
| 6 | U-21366 | Michigan Gas Utilities Corporation rate case |
| 7 | U-21406 | DTM Michigan Gathering Company Gas transportation rates case |
| 8 | U-21490 | Consumers Energy Company gas rate case |
| 9 | U-21510 | Consumers Energy Company & DTE Gas Company Act 9 case |
| 10 | U-21525 | DTE Michigan Lateral Company transportation rates case |
| 11 | U-21529 | DTE Gas Company Act 69 case |
| 12 | U-21540 | Michigan Gas Utilities Corporation rate case |
| 13 | U-21589 | Consumers Energy Company Act 9 case |
| 14 | U-21622 | Complaint against Consumers Energy Company case |
| 15 | U-21624 | SEMCO Energy Gas Company MRP and IRIP case |
| 16 | U-21629 | Consumers Energy Company Act 9 case |
| 17 | U-21637 | MCL 460.6a Application Process Investigation case |
| 18 | U-21780 | SEMCO Energy Gas Company Act 9 case |
| 19 | U-21782 | Ameresco Woodland Meadows Romulus LLC Act 9 case |
| 20 | U-21785 | SEMCO Energy Gas Company Act 9 case |
| 21 | U-21825 | SEMCO Energy Gas Company Act 69 case |
| 22 | U-21839 | DTE Gas Company Technical Standards for Gas Service waiver case |
| 23 | U-21842 | Consumers Energy Company Act 9 case |



VERITEXT LEGAL SOLUTIONS

**QUALIFICATIONS OF KEVIN P. SPENCE**
**CASE NUMBER U-21806**
**PART I**

U-21854 Consumers Energy Company Act 9 case

Q. Have you filed testimony before the MPSC in any of the aforementioned cases?

A. Yes, I have filed testimony before the MPSC in the following cases:

| Case No. | Case Description |
|---|---|
| U-18424 | Consumers Energy Company gas rate case |
| U-20198 | Zeeland Farm Services Ithaca, LLC Act 9 case |
| U-20322 | Consumers Energy Company gas rate case |
| U-20479 | SEMCO Energy Gas Company gas rate case |
| U-20618 | Consumers Energy Company Act 9 case |
| U-20894 | DTE Michigan Lateral Company Act 9 case |
| U-20940 | DTE Gas Company gas rate case |
| U-20993 | Saginaw Bay Pipeline Company Act 9 case |
| U-21291 | DTE Gas Company gas rate case |
| U-21292 | Michigan Gas Utilities Corporation Act 9 case |
| U-21308 | Consumers Energy Company gas rate case |
| U-21490 | Consumers Energy Company gas rate case |
| U-21498 | DTE Gas Company Act 9 case |
| U-21525 | DTE Michigan Lateral Company transportation rates case |
| U-21540 | Michigan Gas Utilities Corporation rate cases |
| U-21622 | Complaint against Consumers Energy Company case |
| U-21780 | SEMCO Energy Gas Company Act 9 case |

**DIRECT TESTIMONY OF KEVIN P. SPENCE**
**CASE NUMBER U-21806**
**PART II**

Q. What is the purpose of your direct testimony in this proceeding?

A. The purpose of my direct testimony in this proceeding is to provide Staff's analysis and recommendations to the Commission regarding Consumers Energy Company's (Consumers Energy or the Company) proposed capital expenditure projects and relevant operation and maintenance (O&M) expenditures.

Q. How is your direct testimony organized?

A. My direct testimony is organized into the following three sections:

I. Summary of Company Expenditures Reviewed

II. Summary of Recommended Adjustments

III. Overall Recommendations

It should be understood that the following direct testimony only addresses the topics detailed above, discussed herein, and anything additional that may be addressed in the final Overall Recommendations section. Additional Staff expert witnesses may, or may not, provide additional analysis and recommendations related to the topics contained in the direct testimony herein.

Q. Are you sponsoring any exhibits in this proceeding?

A. Yes, I am sponsoring the following three exhibits:

Exhibit S-16.1: U-21835 Capital Expenditures, is a 2-page exhibit which displays the Staff discovery requests, and Company responses, with regard to the Company's projected capital expenditures related to the ongoing Act 9 application in MPSC Case No. U-21835.

Exhibit S-16.2: U-21854 Capital Expenditures, is a 3-page exhibit which displays the Staff discovery requests, and Company responses, with regard to the

Company's projected capital expenditures related to the ongoing Act 9 application in MPSC Case No. U-21854.

Exhibit S-16.3: U-21842 Capital Expenditures, is a 2-page exhibit which displays the Staff discovery requests, and Company responses, with regard to the Company's projected capital expenditures related to the ongoing Act 9 application in MPSC Case No. U-21842.

Q. Were these exhibits prepared by you or under your direction?

A. Yes. These exhibits were prepared by me, or under my direction; however, some of the source information contained in the exhibits was generated by others.

## I. Summary of Company Expenditures Reviewed

Q. Which of the Company's expenditures have you reviewed and are the subject of this direct testimony?

A. I've reviewed a number of the Company's programs which are classified as capital and operations and maintenance (O&M) expenditures.

Q. Specifically, which capital expenditure programs have you reviewed?

A. Specifically, the capital expenditure programs which I've reviewed are: Asset Relocation Program; Regulatory Compliance Program; Capacity/Deliverability Program; Freedom Upgrade Project; Compression; Storage; New Well; Well Rehabilitation; Storage Pipeline Replacement; Well Data Acquisition; Riverside Field Retirement; and Safety Valve Installation.

Q. Does Staff have any concerns regarding the Company's proposed capital expenditures as they relate to the aforementioned programs?

A. Yes. In the following section of this direct testimony, adjustments are proposed to address Staff's concerns with the Company's proposed capital expenditures for the New Well and Storage Pipeline Replacement programs.

Q. Specifically, which O&M expenditure programs have you reviewed?

A. Specifically, the O&M expenditure programs which I've reviewed are: MAOP Transmission; Corrosion Control – Transmission; Pipeline Integrity – TOD; Pipeline Integrity – Transmission; Gas Compression; Compression Rebuilds; and Renewable Natural Gas.

Q. Does Staff have any concerns regarding the Company's proposed O&M expenditures as they relate to the aforementioned programs?

A. No. Staff does not have any concerns regarding the Company's proposed O&M expenditures as they relate to the aforementioned programs.

## II. Summary of Recommended Adjustments

Q. Please reiterate which of the Company's proposed programs Staff has concern.

A. Of the Company programs which have been reviewed and addressed within this direct testimony, Staff has concern with the following two capital expenditure programs: New Well and Storage Pipeline Replacement.

Q. Which Company witness sponsored direct testimony and exhibits supporting the proposed capital expenditures related to the New Well Program?

A. New Well Program capital expenditures are sponsored by Company witness Timothy K. Joyce.

Q. Please briefly describe what capital expenditures the Company is proposing related to the New Well Program, as sponsored by Company witness Joyce.

A. As shown on Company Exhibit A-12 (TKJ-5), Schedule B-5.7, page 1, line 4, the capital expenditures for the New Well Program were $11,403,000 in 2023, and are projected to be $17,202,000 in 2024, $28,004,000 for the 10 months ending October 31, 2025, and $32,296,000 for the 12 months ending October 31, 2026.

Q. What concern does Staff have with regarding the Company's sponsored capital expenditures for the New Well Program?

A. Staff has two concerns regarding the Company's sponsored capital expenditures for the New Well Program, both of which pertain to ongoing Act 9 applications before the Commission. First, the Company has included capital expenditures in this instant case related to MPSC Case No. U-21835. Second, the Company has included capital expenditures in this instant case related to MPSC Case No. U-21854.

Q. Please briefly describe MPSC Case No. U-21835.

A. MPSC Case No. U-21835, per the application, is an Act 9 application whereby the Company is requesting the Commission grant approval for the construction and operation of a new pipeline connecting a new C-1103 Well to the designated tie-in location on the CL-WL-993 pipeline ("C-1103 Well Line"). As mentioned, this case is currently before the Commission and has not, as of the filing of this direct testimony, received a final order.

Q. Please briefly describe MPSC Case No. U-21854.

A. MPSC Case No. U-21854, per the application, is an Act 9 application whereby the Company is requesting the Commission grant approval for the construction and operation of new 4-inch pipelines connecting the new W-1004, W-1005, and W-

1006 wells to the W-56N Lateral (the "W-1004, W-1005, and W-1006 Well Lines"), and upsizing the 4-inch W-56N Lateral to 6-inch pipe in the Winterfield Storage Field. As mentioned, this case is currently before the Commission and has not, as of the filing of this direct testimony, received a final order.

Q. What concern does Staff have with the inclusion of capital expenditures in this instant case regarding MPSC Case Nos. U-21835 and U-21854.

A. As mentioned, MPSC Case Nos. U-21835 and U-21854 are ongoing Act 9 applications which have not, as of the filing of this direct testimony, received respective Commission orders approving the projects. Absent a Commission order granting approval for the Company's projects, there is no guarantee that the projects will be approved. If the Company were allowed to recover the full amount of the requested capital expenditures for the projects, and the Commission does not issue an order approving the construction and operation of the proposed pipelines, then the Company's rate payers would be unjustly funding a project of which they will not realize benefits.

Q. Does Staff have any recommendations with regard to the Company's sponsored capital expenditures for the New Well Program, specifically as they relate to the inclusion of capital expenditures for MPSC Case Nos. U-21835 and U-21854?

A. Yes. Regarding MPSC Case No. U-21835, Staff recommends the Commission disallow the following: $968,000 for the 12 Months Ending December 31, 2024; $5,671,000 for the 10 Months Ending October 31, 2025; and $1,150,000 for the 12 Months Ending October 31, 2026. Regarding MPSC Case No. U-21854, Staff recommends the Commission disallow the following: $1,699,000 for the 12

Months Ending December 31, 2024; $19,268,000 for the 10 Months Ending October 31, 2025; and $3,341,000 for the 12 Months Ending October 31, 2026.

Q. Why is Staff recommending the Commission specifically disallow the aforementioned expenses and not the entirety of expenses related to the respective Act 9 applications in MPSC Case Nos. U-21835 and U-21854?

A. Company witness Joyce, through discovery response, provided a breakdown of the Application Filing Expenses and Post Application Expenses for each Act 9 application in MPSC Case Nos. U-21835 and U-21854. Staff supports the inclusion of the Application Filing Expenses in this instant case; it is the Post Application Expenses that concern Staff absent Commission orders approving the respective applications in MPSC Case Nos. U-21835 and U-21854. Staff's recommended disallowances correspond to the respective Post Application Expenses for each application in MPSC Case Nos. U-21835 and U-21854. Please refer to Staff Exhibits S-16.1 and S-16.2 to review the discovery requests, and Company responses, regarding the capital expenditure breakdown for MPSC Case Nos. U-21835 and U-21854, respectively, which are included in this instant case.

Q. Which Company witness sponsored direct testimony and exhibits supporting the proposed capital expenditures related to Storage Pipeline Replacement Program?

A. Storage Pipeline Replacement Program capital expenditures are sponsored by Company witness Joyce.

Q. Please briefly describe what capital expenditures the Company is proposing related to the Storage Pipeline Replacement Program, as sponsored by Company witness Joyce.

A. As shown on Company Exhibit A-12 (TKJ-5), Schedule B-5.7, page 1, line 6, the capital expenditures for the Storage Pipeline Replacement Program were $3,550,000 in 2023, and are projected to be $14,836,000 in 2024, $24,398,000 for the 10 months ending October 31, 2025, and $20,930,000 for the 12 months ending October 31, 2026.

Q. What concern does Staff have with regarding the Company's sponsored capital expenditures for the Storage Pipeline Replacement Program?

A. Similar to Staff's aforementioned concern with the Company's sponsored capital expenditures for the New Well Program, Staff is concerned with the Company's included capital expenditures in this instant case related to MPSC Case No. U-21842.

Q. Please, briefly, describe MPSC Case No. U-21842.

A. MPSC Case No. U-21842, per the application, is an Act 9 application whereby the Company is requesting the Commission grant approval for the construction and operation of new and re-routed pipelines in the Hessen Storage Field. As mentioned, this case is currently before the Commission and has not, as of the filing of this direct testimony, received a final order.

Q. What concern does Staff have with the inclusion of capital expenditures in this instant case regarding MPSC Case No. U-21842?

A. As mentioned, and similar to Staff's concern with MPSC Case Nos. U-21835 and U-21854, MPSC Case No. U-21842 is an ongoing Act 9 application which has not, as of the filing of this direct testimony, received a Commission order approving the project. Absent a Commission order granting approval for the

Company's project, there is no guarantee that the project will be approved. If the Company were allowed to recover the full amount of the requested capital expenditures for the project, and the Commission does not issue an order approving the construction and operation of the proposed pipelines, then the Company's rate payers would be unjustly funding a project of which they will not realize benefits.

Q. Does Staff have any recommendations with regard to the Company's sponsored capital expenditures for the Storage Pipeline Replacement Program, specifically as they relate to the inclusion of capital expenditures for MPSC Case No. U-21842?

A. Yes. Regarding MPSC Case No. U-21842, Staff recommends the Commission disallow the following: $279,000 for the 12 Months Ending December 31, 2024; $13,750,000 for the 10 Months Ending October 31, 2025; and $2,003,000 for the 12 Months Ending October 31, 2026.

Q. Why is Staff recommending the Commission specifically disallow the aforementioned expenses and not the entirety of expenses related to the Act 9 application in MPSC Case No. U-21842?

A. Company witness Joyce, through discovery response, provided a breakdown of the Application Filing Expenses and Post Application Expenses the Act 9 application in MPSC Case No. U-21842. Staff supports the inclusion of the Application Filing Expenses in this instant case; it is the Post Application Expenses that concern Staff absent Commission orders approving the application in MPSC Case No. U-21842. Staff's recommended disallowances correspond to

the Post Application Expenses for the application in MPSC Case No. U-21842. Please refer to Staff Exhibits S-16.3 to review the discovery requests, and Company responses, regarding the capital expenditure breakdown for MPSC Case No. U-21842 which are included in this instant case.

## III. Overall Recommendations

Q. Please, briefly, reiterate Staff's recommendations contained herein.

A. To reiterate, Staff recommends the following to the Commission:

- The disallowance of $968,000 for the 12 Months Ending December 31, 2024; $5,671,000 for the 10 Months Ending October 31, 2025; and $1,150,000 for the 12 Months Ending October 31, 2026 from the Company's New Well Program, as the capital expenditures relate to the ongoing Act 9 application in MPSC Case No. U-21835;
- The disallowance of $1,699,000 for the 12 Months Ending December 31, 2024; $19,268,000 for the 10 Months Ending October 31, 2025; and $3,341,000 for the 12 Months Ending October 31, 2026 from the Company's New Well Program, as the capital expenditures relate to the ongoing Act 9 application in MPSC Case No. U-21854; and
- The disallowance of $279,000 for the 12 Months Ending December 31, 2024; $13,750,000 for the 10 Months Ending October 31, 2025; and $2,003,000 for the 12 Months Ending October 31, 2026 from the Company's Storage Pipeline Replacement Program, as the capital expenditures relate to the ongoing Act 9 application in MPSC Case No. U-21842.

**DIRECT TESTIMONY OF KEVIN P. SPENCE**
**CASE NUMBER U-21806**
**PART II**

Q. Does Staff have any more discussion to convey regarding the aforementioned recommendations for disallowance?

A. Yes. Should the Act 9 applications in MPSC Case Nos. U-21835, U-21842, or U-21854 receive a Commission order approving the respective application prior to the completion of this instant case, Staff may consider withdrawing the recommendations contained within this direct testimony.

Q. Is there anything additional that Staff would like to discuss within this direct testimony?

A. No.

Q. Does this conclude your direct testimony?

A. Yes, it does.



VERITEXT LEGAL SOLUTIONS

**S T A T E OF M I C H I G A N**

**BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION**

*** * * ***

| | | |
|---|---|---|
| **In the matter of the application of CONSUMERS ENERGY COMPANY for authority to increase its rates for the distribution of natural gas and for other relief.** | **)** | **Case No. U-21806** |

# EXHIBITS OF

# KEVIN P. SPENCE

# MICHIGAN PUBLIC SERVICE COMMISSION

**April 23, 2025**

MS. STIRLING: Staff calls to be filed the qualifications and direct testimony of Jacob Martus that consists of a cover sheet and eight pages of questions and answers. Mr. Martus sponsored three exhibits associated with his direct testimony. These exhibits have been marked Exhibit S-17.1, Exhibit S-17.2, and Exhibit S-17.3.

The Staff moves to bind into the record the qualifications and direct testimony and to admit the exhibits of Jacob Martus.

JUDGE VARCHETTI: All right. Are there any objections to binding in the testimony, the direct testimony, of Mr. Martus or admitting any of his three associated exhibits?

I am hearing none, so the testimony is bound into the record and the exhibits are admitted.

(Direct Testimony and Qualifications bound in)

**S T A T E  O F  M I C H I G A N**

**BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION**

*** * * ***

| | | |
|---|---|---|
| **In the matter of the application of CONSUMERS ENERGY COMPANY for authority to increase its rates for the distribution of natural gas and for other relief.** | **)** | **Case No. U-21806** |

# QUALIFICATIONS AND DIRECT TESTIMONY OF

# JACOB G. MARTUS

# MICHIGAN PUBLIC SERVICE COMMISSION

**April 23, 2025**

**QUALIFICATIONS OF JACOB G. MARTUS**
**CASE NUMBER U-21806**
**PART I**

**Q. Please state your name, business address, and occupation.**

A. My name is Jacob G. Martus, and my business address is 7109 West Saginaw Highway, Lansing, Michigan. I am employed by the Michigan Public Service Commission (MPSC or Commission) as a Public Utility Engineer in the Infrastructure Section of the Gas Safety and Operations Division.

**Q. On whose behalf are you testifying?**

A. I am testifying on behalf of the MPSC Staff (Staff).

**Q. What is your educational background and work experience?**

A. I earned a Bachelor of Science degree in Mechanical Engineering from University of Michigan in 2023. I began my employment with the MPSC in January 2024 as a Public Utility Engineer. My responsibilities as a Public Utility Engineer include engineering duties related to the Commission's regulation of natural gas well production and proration; transmission of natural gas, crude oil, and petroleum products by pipeline; underground natural gas storage; gas pipeline safety; compliance with gas technical standards, including review of gas utilities' meter testing programs; and various other gas utility functions, including review of gas utilities' customer attachment programs and complaints or inquiries related to those programs.

**Q. Have you participated in any other cases before the MPSC prior to this current proceeding?**

A. Yes. I have participated in the following cases before the MPSC:

| Case No. | Case Description |
|---|---|
| U-21291 | DTE Gas Company gas rate case |

**QUALIFICATIONS OF JACOB G. MARTUS**
**CASE NUMBER U-21806**
**PART I**

U-21490 Consumers Energy Company gas rate case

U-21540 Michigan Gas Utilities Corporation gas rate case

U-21624 SEMCO Energy Gas Company MRP and IRIP extension/amendment

U-21785 SEMCO Pipeline Company Belle River Pipeline Act 9 case

U-21825 SEMCO Energy Gas Company Mussey Township Act 69 case

U-21835 Consumers Energy Company C-1103 Well Line Act 9 case

**Q. Have you filed testimony before the MPSC in any of the aforementioned cases?**

A. No.

**DIRECT TESTIMONY OF JACOB G. MARTUS**
**CASE NUMBER U-21806**
**PART II**

**Q. What is the purpose of your direct testimony in this proceeding?**

A. The purpose of my direct testimony in this proceeding is to provide Staff's analysis and recommendations to the Commission regarding Consumers Energy Company's (Consumers Energy or the Company) requested regulatory deferral mechanisms for the Leak Detection and Repair program and Staking and Locating sub-program.

**Q. How is your direct testimony organized?**

A. My direct testimony is organized into the following sections:

I. REGULATORY DEFERRAL MECHANISMS ..... 5
A. Leak Detection and Repair ..... 5
B. Staking and Locating ..... 7

The following direct testimony only addresses the topics detailed above, and anything additional that may be addressed in the final Overall Recommendations section. Additional Staff expert witnesses may, or may not, provide additional analysis and recommendations related to the topics contained in the direct testimony herein.

**Q. Are you sponsoring any exhibits in this proceeding?**

A. Yes, I am sponsoring the following three exhibits:

Exhibit S-17.1: Consumers Energy's Audit Response U21806-SA-CE-319, is a 1-page exhibit which displays the Company's response to Staff's audit request regarding projected O&M expenditures related to the LDAR Leak Backlog.

Exhibit S-17.2 Consumers Energy's Audit Response U21806-SA-CE-318, is a 1-page exhibit which displays the Company's response to Staff's audit request regarding projected capital expenditures related to the LDAR Leak Backlog.

Exhibit S-17.3: Consumers Energy's Audit Response U21806-SA-CE-428, is a 3-page exhibit which displays the Company's response to Staff's audit request regarding the Company's possible fluctuation in staking volume.

**Q. Were these exhibits prepared by you or under your direction?**

A. Yes. These exhibits were prepared by me, or under my direction; however, some of the source information contained in the exhibits was generated by others.

## I. REGULATORY DEFERRAL MECHANISMS

### A. Leak Detection and Repair

**Q. Which Company witnesses sponsored direct testimony pertaining to PHMSA's proposed Leak Detection and Repair (LDAR) rule?**

A. For PHMSA's proposed LDAR rule, James P. Pnacek, Jr and Kristine A. Pascarello sponsored testimony pertaining to the O&M and capital spending respectively.

**Q. Please briefly describe what requirements of the proposed LDAR rule the Company intends to comply with, as sponsored by Company witnesses James P. Pnacek, Jr and Kristine A. Pascarello.**

A. Per pages 8-10 and pages 64-65 of James P. Pnacek, Jr's and Kristine A. Pascarello's testimony respectively, the Company intends to comply with the entirety of the proposed LDAR rule upon its publishment. However, the Company

has also expressed that they will comply with the requirement to repair all known grade 2 and grade 3 leaks (the Leak Backlog) regardless of whether the rule is published or not.

**Q. Please briefly describe what O&M expenditures the Company is proposing related to the LDAR Leak Backlog, as sponsored by Company witness James P. Pnacek, Jr.**

A. As stated on page 10 of Company witness James P. Pnacek, Jr.'s testimony and provided in the audit response shown in Exhibit S-17.1, the company is proposing an O&M expenditure of $1,300,000 for the test year.

**Q. Please briefly describe what capital expenditures the Company is proposing related to the LDAR Leak Backlog, as sponsored by Company witness Kristine A. Pascarello.**

A. As stated on page 65 of Company witness Kristine A. Pascarello's testimony and provided in the audit response shown in Exhibit S-17.2, the company is proposing a capital expenditure of $1,510,000 for the test year.

**Q. Does Staff have any concerns or recommendations regarding the Company's sponsored O&M and capital expenditures for the LDAR Leak Backlog?**

A. Yes. Staff finds that the repair of the known grade 2 and grade 3 leaks is reasonable in cost and prudent for safety, and Staff supports the repairs regardless of the proposed LDAR rule's passing.

**Q. Please briefly describe the purpose of the Company's requested regulatory deferral mechanism for the proposed LDAR requirements, as sponsored by Company witnesses James P. Pnacek, Jr and Kristine A. Pascarello.**

A. The requested regulatory deferral mechanism would recover the O&M and capital expenses for complying with the proposed LDAR rule's requirements upon the rule's publishment (except for the Leak Backlog's repair which has its expenses included in the rate base).

**Q. Does Staff have any concerns or recommendations regarding the Company's requested regulatory deferral mechanism for the proposed LDAR rule's requirements?**

A. Yes. The Company has expressed that the expected publish date for the rule was January 2025. However, as of this testimony being filed in April 2025, the rule hasn't been published on PHMSA's database [1]. In addition, an executive order [2] was issued in January 2025 which introduces a new and significant consideration to the passing of the rule. Because of this, Staff's opinion is that PHMSA's proposed LDAR rule is highly unlikely to come into effect for the period the regulatory deferral mechanism is being requested, and hence, Staff doesn't support the use of a regulatory deferral mechanism for the proposed LDAR rule.

[1] https://www.whitehouse.gov/presidential-actions/2025/01/unleashing-prosperity-through-deregulation/

[2] https://www.federalregister.gov/agencies/pipeline-and-hazardous-materials-safety-administration

## B. Staking and Locating

**Q. Which Company witness sponsored direct testimony pertaining to the Company's Staking and Locating sub-program?**

A. James P. Pnacek, Jr. sponsored testimony pertaining to the O&M spending of the Staking and Locating sub-program.

**Q. Please briefly describe what O&M expenditures the Company is proposing related to the Staking and Locating sub-program, as sponsored by Company witness James P. Pnacek, Jr.**

A. As shown on pages 44-45 and Tables 29 and 30 of Company witness James P. Pnacek, Jr.'s testimony, the company is proposing an O&M expenditure of $24,457,485 for the test year.

**Q. Does Staff have any concerns or recommendations regarding the Company's sponsored O&M expenditures for the Staking program?**

A. No.

**Q. Please briefly describe the staking volume the Company is proposing related to the Staking and Locating sub-program, as sponsored by Company witness James P. Pnacek, Jr.**

A. As shown on page 46 and Table 31 of Company witness James P. Pnacek, Jr.'s testimony and provided in the audit response shown in Exhibit S-17.3, the company is proposing a base unit ticket volume of 482,380 for the 2026 projected year.

**Q. Please briefly describe the purpose of the Company's requested regulatory deferral mechanism for the Staking and Locating sub-program, as sponsored by Company witnesses James P. Pnacek, Jr.**

A. As shown in Exhibit S-17.3, the Company has identified two projects (Realizing Opportunities with Broadband Infrastructure Networks or "ROBIN" and Broadband Equity, Access, and Deployment Program or "BEAD") which they assert can cause significant fluctuations in the staking volume. Hence, the

Company is requesting a regulatory deferral mechanism to refund spending below or recover spending above the amount in the rate case.

**Q. Does Staff have any concerns or recommendations regarding the Company's requested regulatory deferral mechanism for the Staking and Locating sub-program?**

A. Yes, Staff supports use of a regulatory deferral mechanism for the Staking and Locating sub-program. However, Staff supports the use of a regulatory deferral mechanism for only fluctuations stemming from the variability in staking volume. Therefore, Staff recommends that the regulatory deferral mechanism be capped to and bounded by the amount set forth by the audit response shown in Exhibit S-17.3 of this testimony. That is, for the 2026-year, the regulatory deferral mechanism would recover up to the amount shown in Equation 1 below where "x" is the base unit ticket volume the company experiences for the projected 2026-year and would refund exactly the amount shown in Equation 1 when "x" is below the projected 482,380 volume. In addition, the recovery and refund through Equation 1 would be capped at $2,297,630 and $(726,724) respectively.

Equation 1: (x – 482,380) *45.67 dollars

**Q. Is there anything additional that Staff would like to discuss within this direct testimony?**

A. No.

**Q. Does this conclude your direct testimony?**

A. Yes, it does.

MS. STIRLING: Staff calls to be filed the qualifications and direct testimony of Emma Zichi that consists of a cover sheet and 15 pages of questions and answers. I would note for the record that Ms. Zichi's testimony has been filed as both public and confidential versions.

Ms. Zichi sponsored three exhibits associated with her direct testimony. These exhibits have been marked Exhibit S-19, Exhibit S-19.1, and Exhibit S-19.2. Exhibit S-19.2 is confidential and has been filed under seal.

The Staff moves to admit the qualifications and direct testimony and to admit the exhibits of Emma Zichi.

JUDGE VARCHETTI: Are there any objections to binding in the direct testimony, both public and confidential, of Ms. Zichi or admitting any of her associated exhibits?

I am hearing none, so the testimony is bound into the record, and the exhibits, the associated exhibits, are admitted.

(Direct Testimony and Qualifications bound in)

**STATE OF MICHIGAN**

**BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION**

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Case No. U-21806

In the matter of the application of
**CONSUMERS ENERGY COMPANY**
for authority to increase its rates for the
distribution of natural gas and for other relief.

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# QUALIFICATIONS AND DIRECT TESTIMONY OF

# EMMA ZICHI

# MICHIGAN PUBLIC SERVICE COMMISSION

April 23, 2025

**QUALIFICATIONS AND DIRECT TESTIMONY OF**
**EMMA ZICHI**
**U-21806**

Q. Please state your full name and business address for the record.

A. My name is Emma Zichi, and my business address is 7109 W. Saginaw Hwy., Lansing, MI 48917.

Q. By whom are you employed and in what capacity?

A. I am employed by the Michigan Public Service Commission (MPSC or Commission) as an Analyst in the Data Access, Privacy and IT (DAPIT) Section of the Customer Assistance Division (CAD).

Q. Please describe your educational background.

A. I earned a Bachelor of Science in Psychology from Michigan State University in 2021 and a Master of Social Work degree from the University of Michigan in 2022.

Q. What is your professional experience?

A. I began working at the MPSC as an Analyst within the DAPIT section in 2024. My responsibilities include analyzing utilities' rate case cost recovery requests related to Information Technology (IT) as well as Physical and Cyber Security. Prior to working at the MPSC I worked as an Outpatient Therapist and at Auto-Owners Insurance as an Associate Quality Analyst where I tested company software systems to ensure quality and accuracy of system changes.

Q. Have you received any work-related training since your employment with the MPSC?

A. Yes. I have completed the NARUC RTI- Rate Case Basics training.

Q. Have you previously filed testimony before the Commission?

A. No.

Q. What is the purpose of your testimony in this proceeding?

A. The purpose of my testimony is to present the Michigan Public Service Commission Staff's (Staff) recommendations regarding Consumers Energy Company's (Consumers or the Company) request for recovery of proposed Information Technology (IT) capital expenditures for the bridge period and projected test year, and investment O&M expenditures for the test year in this case. Additionally, I will present Staff's position regarding the Company's requests for the SAP S/4 HANA upgrade project.

Q. Are you sponsoring any exhibits in this proceeding?

A. Yes. I am sponsoring the following exhibits:

Exhibits:

S-19.0: Staff's Adjustments to IT Capital and Investment O&M by Project

S-19.1: Company Audit Responses

S-19.2: Confidential Company Discovery Response

Q. Were these exhibits prepared by you or under your direction?

A. Yes.

Q. What adjustments is Staff recommending to the Company's Information Technology expenditures?

A. Staff is recommending a total disallowance of $45,683 in the historical 12-months ending 12/31/2023, $277,074 in the12-month bridge period ending 12/31/2024, $2,474,289 in the 10-month bridge year period ending 10/31/2025 and $3,150,209 in the test year ending 10/31/2026 (Exhibit S-19.0). These expenditures come from the following programs: Corporate, Electric & Gas Shared, IT/Digital Foundation, and Security and correspond to Exhibit A-12 (SHB-4) lines 1-3,5 and 6. Staff witness Brittney Klocke is

testifying to adjustments in the Customer program.

Q. What adjustments are Staff recommending to the Corporate program?

A. Staff is recommending a disallowance of $33,023 in capital and $62,564 in O&M to the corporate program. This recommendation is made up of the following project-level adjustments: Application Currency-Corporate-Capital, HR-Support Pack and Business Software Inc Upgrade 2025 and HR-Support Pack and Business Software Inc Upgrade 2026. I will address each of these projects below.

Q. What is Staff's recommended adjustment for the Application Currency – Corporate – Capital project?

A. Staff is recommending a partial disallowance of $15,010 in the 10-month bridge year ending 10/31/2025, and $18,013 in the projected test year ending 10/31/2026. (Staff Exhibit S-19.0, line 1.) This adjustment corresponds to the capital expenditures present on Company Exhibit A-20 (SHB-5), pages 16 and 21, lines 230 and 308 and falls within the Corporate Program on Exhibit A-12 (SHB-4), Schedule B-5.1, page 1, line 1. Staff is also recommending a partial disallowance of $1,991 in the projected O&M expense, which falls within the Information Technology Investment O&M program on Exhibit A-19 (SHB-3), page 1, line 3 corresponds to the O&M expense shown on Exhibit A-20, pages 16 and 21, lines 230 and 308.

Q. Why is Staff recommending this adjustment?

A. Staff is recommending this adjustment to correct an error that was found through discovery of the Company's Application Currency projects. [redacted]

[redacted]

[redacted] (Exhibit S-19.2, page 2). This adjustment is shown on line 3 of Exhibit S-19.0.

Q. What is Staff's recommended adjustment for the HR Support Pack and Business Software Inc Upgrade 2025 project?

A. Staff is recommending a partial disallowance of $20,119 to the Company's projected investment O&M expense. (Staff Exhibit S-19.0, line 2.) This adjustment corresponds to the O&M expenditures presented on Company Exhibit A-20 (SHB-5), page 16, line 234 and falls within the Information Technology Investment O&M program on Exhibit A-19 (SHB-3), page 1, line 3.

Q. Why is Staff recommending this adjustment?

A. Staff is recommending this adjustment to correct for an error discovered during its audit of the Company's Corporate program projects. In response to an audit request from Staff regarding high projected costs for 2025 and 2026, the Company provided that O&M costs for both years were inadvertently overstated, and did not account for optimization in contractor costs (Exhibit S-19.1, page 3 and 4). This adjustment is shown on line 2 of Exhibit S-19.0.

Q. What is Staff's recommended adjustment for the HR Support Pack and Business Software Inc Upgrade 2026 project?

A. Staff is recommending a partial disallowance of $40,454 to the Company's projected O&M expense. (Staff Exhibit S-19.0, line 3). This adjustment corresponds to the O&M expenditures presented on Company Exhibit A-20 (SHB-5), page 22, line 314 and falls

within the Information Technology Investment O&M program on Exhibit A-19 (SHB-3), page 1, line 3.

Q. Why is Staff recommending this adjustment?

A. Staff is recommending this adjustment to correct for an error discovered during its audit of the Company's Corporate program projects. In response to an audit request from Staff regarding high projected costs for 2025 and 2026, the Company provided that O&M costs for both years were inadvertently overstated, and did not account for optimization in contractor costs (Exhibit S-19.1, page 4). This adjustment is shown on line 3 of Exhibit S-19.0.

Q. What adjustments is Staff recommending to the Electric & Gas Shared program?

A. Staff is recommending a disallowance of $167,867 in capital and $86,870 in O&M to the Electric & Gas Shared program. This recommendation is made up of the following project-level adjustments: Application Currency-Electric & Gas Shared-Capital, Standard Work Plan, and Next Generation electronic Shift Operations Management System e(SOMS) Replacement. I will address each of these projects below.

Q. What is Staff's recommended adjustment for the Application Currency – Electric & Gas Shared-Capital project?

A. Staff is recommending a partial disallowance of $19,146 in the 10-month bridge period ending 10/31/2025, and $22,975 in the projected test year ending 10/31/2026. (Staff Exhibit S-19.0, line 9.) This adjustment corresponds to the capital expenditures presented on Company Exhibit A-20 (SHB-5), pages 17 and 23, lines 250 and 328 and falls within the Electric & Gas Shared Program on Exhibit A-12 (SHB-4), Schedule B-5.1, page 1,

line 3. Staff is also recommending a partial disallowance of $7,962 to the Company's projected O&M expense (Staff Exhibit S-19.0, line 9). This adjustment corresponds to the O&M expenditures presented on Company Exhibit A-20 (SHB-5), pages 17 and 23, lines 250 and 328 and falls within the Information Technology Investment O&M program on Exhibit A-19 (SHB-3), page 1, line 3.

Q. Why is Staff recommending this adjustment?

A. Staff is recommending this adjustment to correct for an error that was found through discovery of the Company's Application Currency projects. [redacted] (Exhibit S-19.2, page 1). This adjustment is shown on line 9 of Exhibit S-19.0.

Q. What is Staff's recommended adjustment for the Standard Work Plan project?

A. Staff is recommending a partial disallowance of $70,665 in O&M expense. (Staff Exhibit S-19.0, line 10). This adjustment corresponds to the O&M expenditures present on Company Exhibit A-20 (SHB-5), page 23, line 335 and falls within the Information Technology program on Exhibit A-19 (SHB-3), page 1, line 3.

Q. Why is Staff recommending this adjustment?

A. Staff is recommending this adjustment to correct for an error that was discovered during its audit of the Company's IT/Digital Foundation program projects. In an audit response request from Staff regarding projected O&M costs included in 2026 for this project the company identified ongoing support costs were inadvertently added (Exhibit S-19.1, page

5 and 6). This adjustment is shown on line 10 of Exhibit S-19.0.

Q. What is Staff's recommended adjustment for the Next Generation electronic Shift Operations Management System (SOMS) Replacement project?

A. Staff is recommending a partial disallowance of $125,746 of capital in the projected test year ending 10/31/2026. (Staff Exhibit S-19.0, line 11.) This adjustment corresponds to the capital expenditures presented on Company Exhibit A-20 (SHB-5), page 23, line 332 and falls within the Electric & Gas Shared Program on Exhibit A-12 (SHB-4), page 1, line 3. Staff is also recommending a partial disallowance of $8,243 of O&M in the projected test year ending 10/31/2026 (Staff Exhibit S-19.0, line 11). This adjustment corresponds to the O&M expenditures presented on Company Exhibit A-20 (SHB-5), page 23, line 332 and falls within the Investment O&M Information Technology program on Exhibit A-19 (SHB-3), page 1, line 3.

Q. Why is Staff recommending this adjustment?

A. Staff is recommending this adjustment to correct for a change in the project that was discovered during its audit of the Company's IT/Digital Foundation program projects. In response to an audit request from Staff regarding projected non-labor other costs, the Company provided that the current system can stay and does not need to migrate so Consumers need for this project has changed (Exhibit S-19.1, page 7). This adjustment is shown on line 11 of Exhibit S-19.0.

Q. What adjustments are Staff recommending to the IT/Digital Foundation program?

A. Staff is recommending a disallowance of $3,672,192 in capital to the IT/Digital Foundation program. This recommendation is made up of the following project-level

adjustments: ARP-Collaboration, ARP-Field Device Asset Management (FDAM), and ARP-Workstation Asset Management (WAM). I will address each of these projects below.

Q. What is Staff recommended adjustment for the ARP – Collaboration project?

A. Staff is recommending a partial disallowance of $6,015 for the 10-month bridge period ending 10/31/2025 and $7,219 in the projected test year ending 10/31/2026. (Staff Exhibit S-19.0, line 13.) This adjustment corresponds to the capital expenditures presented on Company Exhibit A-22 (SHB-7) page 1, line 3, columns e and g and falls within the IT/Digital Foundation Program on Exhibit A-12 (SHB-4), Schedule B-5.1, page 1, line 5.

Q. Why is Staff recommending this adjustment?

A. Staff is recommending this adjustment to correct an error that was discovered during its audit of the Company's IT/Digital Foundation program projects. In response to an audit request from Staff regarding a cost break down for the auditorium refresh, the Company provided the most current quote, which has a lower total projected cost than the one initially used (Exhibit S-19.1, page 8 and 9). This adjustment is shown on line 13 of Exhibit S-19.0.

Q. What is Staff's recommended adjustment for the ARP – Field Device Asset Management (FDAM) project?

A. Staff is recommending a full disallowance to the new device purchases for 2025 and 2026 that are part of the ARP-FDAM project, which consists of $831,046 for the 10-month bridge period ending 10/31/2025 and $999,543 for the projected test year ending

10/31/2026. (Staff Exhibit S-19.0, line 14.) This adjustment corresponds to the capital expenditures presented on Company Exhibit A-22 (SHB-7) page 14, columns e and g lines 4-6 and falls within the IT/Digital Foundation Program on Exhibit A-12 (SHB-4), Schedule B-5.1, page 1, line 5.

Q. Why is Staff recommending this adjustment?

A. Staff is recommending this adjustment because the Company has not provided clear evidence in support of the expenditures associated with the portion of this project that is intended for new purchases. The Company provides conflicting rationale in testimony and its responses to Staff's audit for how the projected costs were calculated.

Q. Please explain the conflicting information Staff has received.

A. In testimony, Company witness Stacy H. Baker states the projected number of new device purchases for the ARP- FDAM project are based on People and Culture Hiring estimates.[1] In the testimony of Ms. Baker, and in Exhibit A-22 (SHB-7) page 4, column c and d, lines 4-6, the estimated number of new device purchases is the same for 2025 and 2026.[2] In audit, Staff asked the Company if the People and Hiring Estimates are expected to be the same for 2025 and 2026. The Company did not directly answer this question and instead stated that it projected the costs for this project using actuals for validation (Exhibit S-19.1, page 12). The Company claimed that it used historical actuals that were part of the ARP-WAM project and provided these numbers in Audit (Exhibit S-19.1, page 11).

[1] Prefiled direct testimony of Company witness Stacy H. Baker, page 65.
[2] *Id* at page 66.

This is contradictory to testimony because according to Company witness Stacy H. Baker, the device model determines the unit cost.[3] This means the overall cost for the purchase of new devices is based on the number of each model needed and the model cost is used to determine this price breakdown.

The price breakdown for new device purchases is based on how many units of each device is expected to be needed. Each device model has its own unit cost which is applied to the number of units the Company projects are needed to calculate the total projected cost for all new device purchases. In audit, the Company does not specifically state what they based the 2025 and 2026 projections on and only shares they validated these projections based on historical costs. The Company failed to address whether People and Culture estimated hiring data was used to project the number of new devices needed and thus does not support why the number of new devices being purchased in 2025 and 2026 should be the same. Without a clear understanding of what the new purchase projections are based on, and why the projections are shown to be the exact same, Staff does not find that these expenditures have been reasonably supported, and therefore, recommends the Commission disallow the portion of the project that is allocated for new purchases.

Q. What is Staff's recommended adjustment for the ARP – Workstation Management (WAM) project?

[3] *Id* at page 65.

A. Staff is recommending a full disallowance to the new device purchases for 2025 and 2026 that are part of the ARP-WAM project, which consists of $831,077 for the 10-month bridge period ending 10/31/2025 and $997,292 for the projected test year ending 10/31/2026. (Staff Exhibit S-19.0, line 15.) This adjustment corresponds to the capital expenditures presented on Company Exhibit A-22 (SHB-7) page 12, columns e and g lines 8-17 and falls within the IT/Digital Foundation Program on Exhibit A-12 (SHB-4), Schedule B-5.1, page 1, line 5.

Q. Why is Staff recommending this adjustment?

A. Staff is recommending this adjustment due to inconsistent evidence used to support the projected expenditures for the new purchases within the asset refresh project. Similar to the ARP – FDAM project, Company witness Stacy H. Baker testifies that the projected number of new device purchases for the ARP-WAM project are based on People and Culture Hiring estimates[4]. In the testimony of Ms. Baker and in Exhibit A-22 (SHB-7) page 12, columns c and d, lines 8-17 the estimated number of new device purchases is the same for 2025 and 2026. In audit, Staff asked the company why these numbers are the same, and why these numbers in the past have not been the same. The Company shared that these estimates are based on historical new purchase data and People and Hiring Culture estimates (Exhibit S-19.1, page 10). In a follow-up audit question, Staff asked if the People and Hiring Culture estimates were expected to be the same for 2025 and 2026. The Company shared that the previous audit response (Exhibit S-19.1, page 10) was not correct, and that the Company did not use these estimates for the projected number of

[4] *Id* at page 72.

new devices. The Company does not explicitly state how these projections were made and shares that historical actuals were used to validate their cost estimates (Exhibit S-19.1, page 11).

Company Exhibit A-22 (SHB-7) shows the cost for the new purchases is tied to the number of devices being purchased. The Company failed to provide adequate support that its People and Culture Hiring estimates were the same for these years and went on to say these estimates were not used to project the new device purchases for 2025 and 2026, contradicting what is stated in Ms. Baker's testimony.

Q. Did the Company support its position that historical costs should be used to project costs for the ARP-WAM project?

A. No. The Company shared a table of historical actual costs for the ARP-WAM project with Staff in audit (Exhibit S-19.1, page 11). There is no pattern in these historical costs to indicate the same number of new devices would be an accurate prediction for 2025 and 2026. Additionally, the costs for this project are not estimated based on historical costs and then used to determine the number of new devices that need to be purchased. The number of new device purchases determines the projected cost.

Through several audit questions asked by Staff, the Company contradicted their initial stance in testimony regarding where and how the number of projected new purchases was determined. While the Company states in testimony that the bridge and test period projections are based on historical costs, the costs for this project directly relate to the

number of new purchases. The Company could not reasonably prove why the projected number of new device purchases was the same for 2025 and 2025, nor could they prove what the projections were based on. For these reasons, Staff recommends disallowance of the portion of this project dedicated to new purchases.

Q. What adjustment is Staff recommending to the Security program?

A. Staff is recommending a disallowance of $181,600 in capital to the Security program. This recommendation is made up of partial adjustments to the ARP-Physical Security investment. I will address this project below.

Q. What is Staff's recommended adjustment for the ARP-Physical Security project?

A. Staff is recommending a partial disallowance of $72,640 in capital for the bridge period ending 10/31/2025 and $108,960 in capital for the test year ending 10/31/2026. (Staff Exhibit S-19.0, line 17.) This adjustment corresponds to the capital expenditures presented on Company Exhibit A-22 (SHB-7) page 8, line 8 columns e and g and falls within the Security Program on Exhibit A-12 (SHB-4), Schedule B-5.1, page 1, line 6.

Q. Why is Staff recommending this adjustment?

A. Staff is recommending this adjustment to correct for an error that was discovered during its audit of the Security program projects. In response to an audit request from Staff regarding high software, labor, contractor and overhead costs, the Company identified costs for Allowance for Funds Used During Construction (AFUDC) and employee benefits were inadvertently applied to 2025 and the test year ending 10/31/2026 (Exhibit 19.1, page 1 and 2). This adjustment is shown on line 17 of Exhibit 19.0.

Q. What is the Company requesting regarding its SAP S/4HANA upgrade?

A. The Company is requesting deferral of the Investment O&M expenses for this project and will be recovered over the life of the asset. This is addressed by Staff witness Nichols. Additionally, the Company is requesting to amortize the cloud implementation costs for the SaaS over a 15-year asset life. This will be addressed by Staff witness McMillan-Sepkoski.

Q. Does Staff have other recommendations regarding the SAP S/4HANA upgrade?

A. Yes. Staff is recommending the Commission direct the Company to meet with Staff quarterly to inform them on progress of the SAP S/4HANA implementation project. Staff would like these updates to include any advancements and/or setbacks in project implementation, budget adherence, changes to the project scope, timeline, expenses, and any problems the Company has experienced or anticipates experiencing with any operations or customer interactions.

Q. Does Staff have any additional recommendations regarding the SAP S/4HANA upgrade?

A. Yes. Additionally, Staff recommends the Company record any over and under recovery of each projected expense in the SAP S/4HANA implementation, compared to the 80% base (ROM projected investment), to be included in the Company's future rate cases until implementation is complete. This will allow Staff to see how the allocated funds relate to the costs spent on each planned objective.

Q. Please summarize your recommendations.

A. Staff is recommending disallowances for both capital and O&M expenditures for multiple IT projects, and one Security project. Two of these projects are based on unsupported costs, where the Company failed to provide supporting information for these

expenses through audit. All other disallowances are based on errors identified by the company through audit. In total these disallowances account for $1,774,934 in capital for the 10-month bridge period ending 10/31/2025 and $2,279,748 in capital and $149,434 in O&M for the projected test year. Staff also presents recommendations for the Commission to direct the Company to meet with Staff on a quarterly basis to provide updates on the SAP S/4 HANA project. Additionally, Staff is recommending the Company track any over and under spend for the SAP S/4 HANA project to be included in future rate cases and shared at the meetings with Staff.

Q. Does this conclude your testimony?

A. Yes.

(Confidential Direct Testimony bound in in Confidential Record)

MS. STIRLING: Staff calls to be filed the qualifications and direct testimony of Shannon Rueckert that consists of a cover sheet and five pages of questions and answers. Mr. Rueckert sponsored two exhibits associated with his direct testimony. These exhibits have been marked Exhibit S-20.1 and Exhibit S-20.2.

Staff moves to bind into the record the qualifications and direct testimony and to admit the associated exhibits of Shannon Rueckert.

JUDGE VARCHETTI: Are there any objections to the binding in of Mr. Rueckert's direct testimony or the associated exhibits?

I am hearing none, so the testimony is bound into the record, and the exhibits are admitted.

(Direct Testimony and Qualifications bound in)

**STATE OF MICHIGAN**

**BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION**

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Case No. U-21806

In the matter of the application of
**CONSUMERS ENERGY COMPANY**
for authority to increase its rates for the
distribution of natural gas and for other relief.

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# QUALIFICATIONS AND DIRECT TESTIMONY OF

# SHANNON RUECKERT

# MICHIGAN PUBLIC SERVICE COMMISSION

April 23, 2025

**QUALIFICATIONS AND DIRECT TESTIMONY OF**
**SHANNON RUECKERT**
**U-21806**

Q. Please state your name and business address.

A. My name is Shannon Rueckert. My business address is 7109 W. Saginaw Hwy, Lansing, MI 48917.

Q. By whom are you employed and in what capacity?

A. I am employed by the Michigan Public Service Commission (MPSC or Commission) as an auditor in the Revenue Requirements section.

Q. How long have you been employed by the Commission?

A. I have been employed since February of 2018.

Q. What is your educational and professional background?

A. I previously served in the US Air Force as a Fuels Resource Controller, responsible for controlling base wide fuels operations and accounting. My duties included daily close out and reconciliation of all fuel transactions. After serving in the Air Force, I managed a family business. While general manager of the business I performed all managerial accounting functions. In 2015, I graduated from the University of Michigan with a Bachelor of Business Administration and a concentration in accounting degree with High Honors. I was previously employed at Andrew's Hooper Pavlik, PLC as a staff accountant where I performed tax preparation and audits of municipalities, retirement plans, and banks. In April of 2019 I completed the Master of Business Administration program, with a concentration in accounting, at the University of Michigan. I have been involved in rate case audits and performed audit work in the following cases:

| Case No. | Company / Type of Case |
|---|---|
| U-20276 | Upper Peninsula Power Company Electric Rate Case |
| U-20286 | Consumers Energy Company's Tax Cuts and Jobs Act (TCJA) Credit B |

| | |
|---|---|
| U-20322 | Consumers Energy Gas Rate Case |
| U-20359 | Indiana Michigan Company Electric Rate Case |
| U-20642 | DTE Gas Rate Case |
| U-20650 | Consumers Energy Gas Rate Case |
| U-20697 | Consumers Energy Electric Rate Case |
| U-20836 | DTE Electric Rate Case |
| U-20940 | DTE Gas Rate Case |
| U-20963 | Consumers Energy Gas Rate Case |
| U-20995 | UPPCo Transfer of Control Case |
| U-21045 | Alpena Electric Company |
| U-21097 | NSP Electric Company |
| U-21148 | Consumers Energy Electric Rate Case |
| U-21194 | Detroit Thermal Transfer of Control Case |
| U-20836 | DTE Electric Rate Case |
| U-21224 | Consumers Energy Electric Rate Case |
| U-21286 | Upper Peninsula Power Company Electric Rate Case |
| U-21297 | DTE Electric Rate Case |
| U-21308 | Consumers Energy Gas Rate Case |
| U-21366 | Michigan Gas Utilities |
| U-21389 | Consumers Energy Electric Rate Case |
| U-21461 | Indiana Michigan Company Electric Rate Case |
| U-21490 | Consumers Energy Gas Rate Case |
| U-21291 | DTE Gas Rate Case |
| U-21540 | Michigan Gas Utilities Rate Case |
| U-21555 | Upper Peninsula Power Company Electric Rate Case |
| U-21534 | DTE Electric Rate Case |

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to present Staff recommendations relating to the Company's Other Employee Benefits expense for the 12-month period ending October 31, 2026.

Q. Are you sponsoring exhibits?

A. Yes. I am sponsoring the following exhibits:

Exhibit and Title

S-20.1 Other Employee Benefits Expense for the Test Year Ending October 31, 2026.

S-20.2 Other Employee Benefits Leave It Better Award for the Test Year Ending October 31, 2026.

Q. Please describe Exhibit S-20.1.

A. Exhibit S-20.1 presents Staff's Other Employee Benefits projection of $2,668,000 for the 12-month period ending October 31, 2026, a decrease of $550,000 from the Company's request of $3,218,000. Projections were developed through the categories listed in column (a). Column (c) presents the Company's projection. Column (e) presents Staff's projection, with the difference shown in column (d). The difference in column (d) represents Staff's adjustment and are supported by corresponding exhibits listed in column (b).

Q. Please describe Exhibit S-20.2.

A. Exhibit S-20.2 presents the segmented expense projections for the Leave It Better Award program provided by the Company.

**Other Benefits expense Leaving it Better Award (LIBA)**

Q. Please describe the Company's requested Leaving it Better Award (LIBA).

A. In the direct testimony of Kendra K. Grob, page 37, the Company proposed the introduction of an employee award program titled the "Leaving it Better Award". The program is said to award employees that further the "Company's goals, operational excellence, customer satisfaction, and corporate reputation" a lump sum of $4,000. The expense is embedded in the total Other Benefits projection on Exhibit A-64 (KKG-1).

The Company provided the cost of $550,000 in operation and maintenance expense in the projected test year for the LIBA program to Staff. This expense is presented on Exhibit S-20.2.

Q. Does Staff support the Company's request for the ratepayer funded Leaving it Better Award?

A. No. Staff does not support the Company's request for the LIBA program. It is Staff's position that the program does not benefit the ratepayer beyond its cost. Promotability and salary increases are already incentives to achieve operational excellence and customer satisfaction as part of the employees' compensation package. Ratepayers should not be responsible for furthering the Company's Corporate Reputation. Company Witness Amy M. Conrad testified that "[t]he Company's management believes Consumers Energy should pay a fair and reasonable salary, comparable to market that is equitable to employees, consistent with Company values and strategies, and that supports the highest level of customer service at a reasonable cost." *See* the Direct Testimony of Amy M. Conrad, p 10. The Company's Employee Incentive Compensation Program (EICP) already provides short-term incentive compensation for operational goals. Furthering the Company's corporate reputation does not benefit the ratepayer and, if implemented, should be funded by Company shareholders. Staff recommends the Commission reject the LIBA program expense of $550,000 as it does not provide additional benefit to the ratepayer. Staff also recommends a corresponding disallowance of the capital portion of the LIBA totaling $2,387,500 as shown in Figure 1 of Staff Witness Witt's testimony. As shown in Exhibit S-20.2, the Company proposed $824,000 in spending for the bridge

year ending December 31, 2024, $843,000 for the 10 months ending October 31st, 2025, and $864,000 for the test year ending October 31, 2026.

Q. What is Staff's recommendation regarding the Company's proposed Leaving it Better Award?

A. Staff is recommending a disallowance of the Company's Leaving it Better Award program. Staff recommends a decrease of $550,000 from the Company's request of $3,218,000 for O&M and a corresponding capital decrease of $2,387,500. $824,000 for the bridge year ending December 31, 2024, $702,500 for the 10 months ending October 31st, 2025, and $861,000 for the test year ending October 31, 2026.

Q. Does this complete your testimony?

A. Yes.

MS. STIRLING: Staff calls to be filed the qualifications and direct testimony of Cynthia Creisher that consists of a cover sheet and 12 pages of questions and answers. Ms. Creisher filed five exhibits associated with her direct testimony. These exhibits have been marked Exhibit S-22 through Exhibit S-22.4.

The Staff moves to bind into the record the qualifications and direct testimony and to admit the associated exhibits of Cynthia Creisher.

JUDGE VARCHETTI: Are there any objections to binding in the direct testimony of Ms. Creisher or any of her associated exhibits?

I am hearing none, so the testimony is bound into the record and the exhibits are admitted.

(Direct Testimony and Qualifications bound in)

**S T A T E OF M I C H I G A N**

**BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION**

*** * * ***

| | | |
|---|---|---|
| **In the matter of the application of CONSUMERS ENERGY COMPANY for authority to increase its rates for the distribution of natural gas and for other relief.** | **)** | **Case No. U-21806** |

# QUALIFICATIONS AND DIRECT TESTIMONY OF

# CYNTHIA L. CREISHER

# MICHIGAN PUBLIC SERVICE COMMISSION

**April 23, 2025**

**QUALIFICATIONS OF CYNTHIA L. CREISHER**
**CASE NUMBER U-21806**
**PART I**

Q. Please state your name, address, and occupation.

A. My name is Cynthia L. Creisher and my business address is 7109 West Saginaw Highway, Lansing, Michigan. I am employed by the Michigan Public Service Commission (MPSC or Commission) as Manager of the Infrastructure Section of the Gas Safety and Operations Division.

Q. Please briefly describe your educational background and work experience.

A. I earned a Bachelor of Science degree in Mechanical Engineering from Kettering University, formerly GMI Engineering & Management Institute, in 2002. Prior to my employment at the MPSC, I was employed in the automotive manufacturing industry by Fasco DC Motors as a Product Design Engineer where I was responsible for the development, testing, and production launch of electric motors and actuators. I began my employment with the MPSC in February 2009 as a Public Utilities Engineer. During my tenure, I have attended the Annual Regulatory Studies Program sponsored by the National Association of Regulatory Utility Commissioners and numerous seminars, facility tours, and site visits related to the gas industry. My responsibilities as a Public Utilities Engineer included engineering duties related to the Commission's regulation of natural gas well production and proration; transmission of natural gas, crude oil, and petroleum products by pipeline; underground natural gas storage; gas pipeline safety; compliance with gas technical standards, including review of gas utilities' meter testing programs; and various other gas utility functions, including review of gas utilities' customer attachment programs and complaints or inquiries related to those programs. In February 2018, I advanced to a Public Utilities Engineer



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Specialist position as a Data Specialist, where my additional duties included facilitating the Federal Natural Gas Base Grant, maintaining and updating the pipeline safety database, trending operator performance and annual reports, and collection and analysis of damage prevention data. In March 2021, I was promoted to the position of Supervisor of the Infrastructure Unit of the Gas Operations Section, where my duties include directing, coordinating, and supervising programs, activities, and staff. Programs are related to pipeline safety, underground natural gas storage safety, gas infrastructure improvements, gas utility capital and operations and maintenance spending, gas utility programs, natural gas utility certificates of public convenience and necessity (Act 69 of 1929), well connection permits, gas production records, siting for natural gas facilities (Act 9 of 1929), siting for liquid facilities (Act 16 of 1929), siting for natural gas storage (Act 238 of 1923), and Technical Standards for Gas Service (460.2301 et seq.).

Q. Have you participated in any other cases before the Commission prior to this proceeding?

A. Yes, I have participated in the development of Staff's position or filed testimony before the Commission in the following cases:

| Case No. | Case Description |
|---|---|
| U-15766 | MichCon Gathering CO2 treatment complaint |
| U-15985 | MichCon gas rate case |
| U-16230 | Commission's Own Motion regarding operating wells under vacuum |
| U-16280 | Toro Energy waiver of compliance |

**QUALIFICATIONS OF CYNTHIA L. CREISHER**
**CASE NUMBER U-21806**
**PART I**

U-16388 Commission's Own Motion for Continental Resources to show cause

U-16407 MichCon long-term main-renewal plan

U-16451 MichCon long-term meter move out plan

U-16855 Consumers Energy Company gas rate case

U-16999 MichCon gas rate case

U-17169 SEMCO Energy Gas Company main replacement program

U-17197 Consumers Energy Company gas rate case

U-17643 Consumers Energy Company gas rate case

U-17668 Consumers Energy Company meter testing waiver request

U-17701 DTE Gas Company main replacement program

U-17824 SEMCO Energy Gas Company main replacement program

U-17880 Michigan Gas Utilities Corporation gas rate case

U-17882 Consumers Energy Company gas rate case

U-17999 DTE Gas Company gas rate case

U-18124 Consumers Energy Company gas rate case

U-18424 Consumers Energy Company gas rate case

U-18999 DTE Gas Company gas rate case

U-20322 Consumers Energy Company gas rate case

U-20522 Consumers Energy Company infrastructure recovery mechanism reconciliation

U-20479 SEMCO Energy Gas Company gas rate case

U-20642 DTE Gas Company gas rate case



VERITEXT LEGAL SOLUTIONS

**QUALIFICATIONS OF CYNTHIA L. CREISHER**
**CASE NUMBER U-21806**
**PART I**

U-20650 Consumers Energy Company gas rate case

U-20718 Michigan Gas Utilities Corporation gas rate case

U-20893 Consumers Energy Company infrastructure recovery mechanism reconciliation

U-20940 DTE Gas Company gas rate case

U-21148 Consumers Energy Company gas rate case

U-21291 DTE Gas Company gas rate case

U-21308 Consumers Energy Company gas rate case

U-21490 Consumers Energy Company gas rate case

U-21502 Commission's own motion for Consumers Energy Company to show cause



VERITEXT LEGAL SOLUTIONS

**DIRECT TESTIMONY OF CYNTHIA L. CREISHER**
**CASE NUMBER U-21806**
**PART II**

Q. What is the purpose of your testimony in this proceeding?

A. The purpose of my testimony is to present Staff's position and recommendations regarding Consumers Energy Company's (Consumers or the Company) case. I will address the Company's proposed capital expenditures related to the following programs: Enhanced Infrastructure Replacement program (EIRP), Material Condition non-modeled program, and Compliance and Controls. Additionally, I will address the Company's position regarding accounting treatment for MAOP retesting costs.

Q. Are you sponsoring any exhibits in this proceeding?

A. Yes, I am sponsoring the following five exhibits:

(1) S -22.0, Staff Adjustments to Capital Expenditures, is a one-page exhibit summarizing Staff's adjustments to Material Condition non-modeled program as identified in Company Exhibit A-82 (KAP-4), line 2, and Compliance and Controls program as identified in Company Exhibit A-83 (KAP-5), line 4.

(2) S -22.1, Consumers Energy's Response to Staff Audit Request U21806-SA-CE-389, is a one-page exhibit in which the Company responds to Staff's request related to capital expenditures for the Line 1010 project under the Material Condition Non-Modeled program.

(3) S -22.2, Consumers Energy's Response to Staff Audit Request U21806-SA-CE-420, is a one-page exhibit in which the Company responds to Staff's request related to capital expenditures for the Line 1010 project under the Material Condition Non-Modeled program.



VERITEXT LEGAL SOLUTIONS

(4) S-22.3, Consumers Energy's Response to the Attorney General's Discovery Request U21806-AG-CE-0422, is a three-page exhibit in which the Company responds to the Attorney General's request related to the Advanced Methane Detection project under the Compliance and Controls program.

(5) S -22.4, Consumers Energy's Response to Staff Audit Request U21806-SA-CE-421, is a one-page exhibit in which the Company responds to Staff's request related to the Advanced Methane Detection project under the Compliance and Controls program.

**Enhanced Infrastructure Replacement Program**

Q. Please briefly describe the Company's proposal related to the EIRP.

A. The EIRP includes the accelerated replacement of high-risk mains and associated service lines from the Company's distribution system. High-risk materials within the scope of the EIRP include: cast iron mains; bare, oxyacetylene welded, threaded and coupled, Xtrube, and cathodically unprotected main; copper main; metallic service lines associated with EIRP main projects; certain transmission pipe in high consequence areas and operated within the distribution system; and standard pressure main not otherwise included within the scope of vintage main. As described in the testimony of Company witness Kristine Pascarello, the Company has identified a reduction in opportunities to replace high-risk main through grid projects and the need to transition back to more segment projects in 2025 and 2026. The Company also proposes to continue to complete high-pressure steel and transmission within the distribution system (TOD) projects. As detailed in the testimony of Company witness Kristine Pascarello, the Company

plans to complete TOD and high-pressure steel projects totaling approximately eight miles in 2024, 21.5 miles in 2025, and 14.1 miles in 2026 with a projected cost per mile of $3,800,000 in 2025 and $3,910,000 in 2026. The Company plans to complete plastic installation projects totaling approximately 126.4 miles in 2024, 120.5 miles in 2025, and 136.2 miles in 2026. In the previous general gas rate case, Case No. U-21490, the Company developed regional costs per mile for Southwest, Northeast, and Southeast regions and has reevaluated those regional costs in this current case. As shown in Company Exhibit A-84 (KAP-6), the Company projects the cost per mile of plastic installed to be $1,306,077 for Southwest, $1,382,187 for Northeast, and $1,365,542 for Southeast for each year 2024 and 2025. The Company projects the cost per mile of plastic installed to be $1,345,259 for Southwest, $1,423,653 for Northeast, and $1,406,508 for Southeast for 2026. The Company's overall cost per mile for the EIRP varies year over year based on the mileage and respective costs per mile for each region. As shown in Company Exhibits A-82 (KAP-4) and A-84 (KAP-6), the Company proposes to recover capital expenditures related to the EIRP – Distribution program of $195,587,000 in 2024, $250,290,813 in the 2025 program year, and $251,595,761 in the 2025 program year, with $207,322,000 in the 10 months ending October 31, 2025, and $251,372,000 in the test year ending October 31, 2026.

Q. Does Staff support the Company's proposed level of capital expenditures related to the EIRP – Distribution program?

A. Yes. As stated in the direct testimony of Company witness Kristine Pascarello, and supported by the Company's Natural Gas Delivery Plan, which can be found in Company Exhibit A-42 (NPD-1), the EIRP plans to complete the EIRP through the reduction of approximately five percent of vintage main per year. Staff continues to be generally supportive of the accelerated replacement of high-risk main through the EIRP by 2035. Furthermore, Staff finds that the Company's projected costs indicate is that the Company is making progress toward reducing the cost per mile for plastic main installation under the EIRP. As shown in the Company's last general rate case, Case No. U-21490, in Company Exhibit A-99 (KAP-7), the Company projected the cost per mile of plastic installed to be $1,535,859 for Southwest, $1,629,667 for Northeast, and $1,846,877 for Southeast for each year 2023, 2024, and 2025. The Company's current projected costs per mile of plastic installed of $1,345,259 for Southwest, $1,423,653 for Northeast, and $1,406,508 for Southeast for 2026 represent reductions of $190,060 for Southwest, $206,014 for Northeast, and $423,224 for Southeast. Staff urges the Company to continue to implement measures to manage costs and minimize the impact of the EIRP to customers.

**Material Condition Non-Modeled**

Q. Please briefly describe what the Company is proposing related to the Compliance and Controls program.

A. As described in the testimony of Company witness Kristine Pascarello, the Material Condition Non-Modeled program is comprised of Company-initiated replacement projects to address emergent issues. As shown in Company Exhibit

A-82 (KAP-4) and in the testimony of Company witness Kristine Pascarello, the Company is proposing to recover capital expenditures related to the Material Condition Non-Modeled program of $38,256,000 in 2024, $36,358,000 in the 10 months ending October 31, 2025, and $56,206,000 in the test year ending October 31, 2026.

Q. Does Staff support the Company's proposed level of capital expenditures related to the Materials Condition Non-Modeled program?

A. No. In response to Staff Audit Request U21806-SA-CE-389, which is included as Staff Exhibit S-22.1, the Company provided that the preliminary actual costs for the Line 1010 project are lower than the costs as projected in the Company's filed case. Based on the preliminary actual costs, the Company is adjusting the projected capital expenditures for 2025 and 2026. As provided in response to Staff Audit Request U21806-SA-CE-420, which is included as Staff Exhibit S-22.2, the Company originally projected capital expenditures of $14,900,000 in 2025 and $12,800,000 in 2026. The Company's revised projected capital expenditures are $10,846,000 in 2025, where all expenditures are projected to occur in the 10 months ending October 31, 2025, and $9,300,000 in 2026, where all expenditures are projected to occur in the test year ending October 31, 2026.

Q. What is Staff's recommendation concerning capital expenditures related to the Material Condition Non-Modeled program?

A. Staff recommends that the projected capital expenditures for 2025 and 2026 in the Material Condition Non-Modeled program should be adjusted based on the Company's identified reduction in capital expenditures for the Line 1010 project.

Thus, Staff recommends, as shown in Staff Exhibit S-22.0, capital expenditures of $32,304,000 for the 10 months ending October 31, 2025, and $52,706,000 for the test year ending October 31, 2026.

**Compliance and Controls**

Q. Please briefly describe what the Company is proposing related to the Compliance and Controls program.

A. As described in the testimony of Company witness Kristine Pascarello, the Compliance and Controls program is comprised of the following project categories: Advanced Methane Detection; Enterprise Contractor Oversight Dashboard; Enterprise Corrective Action Plan – Gas; Damage Prevention and MISS DIG; and Other. As shown in Company Exhibit A-83 (KAP-5) and in Table 10 in the testimony of Company witness Kristine Pascarello, the Company is proposing to recover capital expenditures related to the Compliance and Controls program of $4,875,000 in 2024, $447,000 in the 10 months ending October 31, 2025, and $4,168,000 in the test year ending October 31, 2026.

Q. Does Staff support the Company's proposed level of capital expenditures related to the Compliance and Controls program?

A. No. In response to the Attorney General's Discovery Request U21806-AG-CE-0422, which is included as Staff Exhibit S-22.3, the Company provided that it no longer projected to spend the capital expenditure amount of $265,000 for the AMD project in 2025, as originally detailed in Table 11 in the direct testimony of Company witness Kristine Pascarello. As provided in response to Staff Audit Request U21806-SA-CE-421, which is included as Staff Exhibit S-22.4, the

Company originally projected the entirety of the capital expenditures of $265,000 in 2025 to occur during the 10 months ending October 21, 2025.

Q. What is Staff's recommendation concerning capital expenditures related to the Compliance and Controls program?

A. Staff recommends that the projected capital expenditures for 2025 in the Compliance and Controls program should be adjusted based on the Company's identified reduction in capital expenditures for the AMD project. Thus, Staff recommends, as shown in Staff Exhibit S-22.0, capital expenditures of $182,000 for the 10 months ending October 31, 2025.

Q. Do you have any additional information to add regarding your adjustment?

A. Yes. Regarding my recommendation for the above Compliance and Controls program adjustment, it should be noted that an incorrect capital expenditure reduction of $295,000 was provided for Staff's revenue deficiency calculation. The impacts of this adjustment are not fully reflected in the testimony and exhibits of other Staff witnesses or in the Staff's revenue deficiency supported by Staff witness Nichols. All impacts of this adjustment will be included in Staff's brief.

**Accounting Treatment for MAOP Retesting Costs**

Q. Please briefly describe what the Company is proposing related to the accounting treatment for MAOP retesting costs.

A. As described in the direct testimony of Company witness Heather Rayl, the Company proposes to capitalize certain one-time retesting costs to reconfirm the MAOP of pipelines in accordance with regulations issued by the Pipeline and

Hazardous Materials Safety Administration. The Company affirms that capitalization of these costs are consistent with Federal Energy Regulatory Commission standards and guidance.

Q. Does the Company include any capitalized costs for retesting costs in this current proceeding?

A. No. As described in the direct testimony of Company witness Michael Griffin, the Company does not include any projects that request capitalization of hydrotesting costs, but the Company does anticipate that there could be such projected in the future.

Q. Does Staff support the Company's request to capitalize certain one-time capitalization of MAOP retesting costs?

A. Yes. Staff is generally supportive of the Company's request; however, since the Company did not include any such projects for review in this current proceeding, Staff recommends that the Company should be subject to reporting requirements to Commission Staff. Staff recommends that the Company should provide notification and opportunity to review by Staff for retesting that is planned to be capitalized prior to testing as well as an annual report of completed testing projects.

Q. Does this conclude your direct testimony?

A. Yes, it does.

MS. STIRLING: Staff calls to be filed the qualifications and direct testimony of Paul Ausum that consists of a cover sheet and five pages of questions and answers. Mr. Ausum sponsored one exhibit associated with his direct testimony. This exhibit has been marked Exhibit S-23.

Staff moves to bind into the record the qualifications and direct testimony and to admit the associated exhibit of Paul Ausum.

JUDGE VARCHETTI: Are there any objections to binding in the direct testimony of Mr. Ausum or his associated exhibit?

Hearing none, the testimony is bound into the record and the exhibit admitted.

(Direct Testimony and Qualifications bound in)

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

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| In the matter of the application of<br>**CONSUMERS ENERGY COMPANY**<br>for authority to increase its rates for the<br>distribution of natural gas and for other relief. | )<br>)<br>)<br>)<br>) | Case No. U-21806 |

**QUALIFICATIONS AND DIRECT TESTIMONY OF**

**PAUL R. AUSUM**

**MICHIGAN PUBLIC SERVICE COMMISSION**

**April 23, 2025**

**QUALIFICATIONS OF PAUL R. AUSUM**
**CASE NUMBER U-21806**
**PART I**

Q. Please state your name and business address.

A. My name is Paul R. Ausum, and my business address is 7109 W. Saginaw Highway, Lansing, Michigan 48917.

Q. By whom are you employed and in what capacity?

A. I am employed as an Economic Analyst in the Resource Adequacy & Forecasting Section of the Energy Resources Division of the Michigan Public Service Commission (MPSC or Commission).

Q. What are your responsibilities in your current position?

A. I am responsible for the analysis of sales and peak demand forecasts in cases that come before the Commission, including rate cases and integrated resource plans (IRPs). This analysis leads to MPSC Staff (Staff) positions and recommendations.

Q. Please outline your educational background.

A. I graduated with a Bachelor of Science degree in Economics from Oakland University in December 2018. From November 2019 to August 2022, I worked as an Economic Analyst in the Act 304 & Sales Forecasting Section of the Energy Operations Division of the Commission. In this role, I conducted analysis of Gas Cost Recovery (GCR) and Power Supply Cost Recovery (PSCR) cases and provided analysis and input that led to Staff positions in rate cases. In August of 2022, I assumed my current position. I have attended the Accounting and Ratemaking course presented by Michigan State University's Institute of Public Utilities (IPU) in February 2021, as well as the Fundamentals course in the theory, principles, and practice of economic regulation of utility companies put on

by IPU as part of its Annual Regulatory Studies Program in August 2021. In June 2023, I attended IPU's Power Grid School on the Engineering and Economics of the Supply Chain for Power, and, in May 2024, I attended a course on the Fundamentals of Long-Term Load Forecasting held by Electric Utility Consultants Incorporated (EUCI).

Q. Have you previously provided testimony before the Commission?

A. Yes. I have provided testimony in the following cases:

| Case Number | Company | Type of Case |
|---|---|---|
| U-20541 | Consumers Energy-Gas | GCR Plan |
| U-20542 | Consumers Energy-Gas | GCR Reconciliation |
| U-20642 | DTE Energy-Gas | Rate Case |
| U-20650 | Consumers Energy-Gas | Rate Case |
| U-20816 | DTE Energy-Gas | GCR Plan |
| U-20817 | DTE Energy-Gas | GCR Reconciliation |
| U-20822 | SEMCO Energy | GCR Plan |
| U-20823 | SEMCO Energy | GCR Reconciliation |
| U-20836 | DTE Energy-Electric | Rate Case |
| U-20940 | DTE Energy-Gas | Rate Case |
| U-21046 | Alpena Power Company | PSCR Plan |
| U-21064 | DTE Energy-Gas | GCR Plan |
| U-21070 | SEMCO Energy | GCR Plan |
| U-21148 | Consumers Energy-Gas | Rate Case |
| U-21193 | DTE Energy-Electric | Integrated Resource Plan |

**QUALIFICATIONS OF PAUL R. AUSUM**
**CASE NUMBER U-21806**
**PART I**

| Case Number | Company | Type of Case |
|---|---|---|
| U-21255 | Alpena Power Company | PSCR Plan |
| U-21297 | DTE Energy-Electric | Rate Case |
| U-21308 | Consumers Energy-Gas | Rate Case |
| U-21461 | Indiana Michigan Power | Rate Case |
| U-21540 | Michigan Gas Utilities Corp. | Rate Case |
| U-21585 | Consumers Energy-Electric | Rate Case |



VERITEXT LEGAL SOLUTIONS

**DIRECT TESTIMONY OF PAUL R. AUSUM**
**CASE NUMBER U-21806**
**PART II**

Q. What is the purpose of your testimony in this proceeding?

A. The purpose of my testimony is to present recommendations to the Commission with regard to the forecast of natural gas sales (deliveries) used as a rate determinant in the application submitted by Consumers Energy Company (Consumers or the Company).

Q. Are you sponsoring any exhibits?

A. Yes. I am sponsoring one exhibit, comprised of an audit response and accompanying data provided by the Company.

| **Exhibit** | **Description** |
|---|---|
| S-23 | Staff Audit Response SA-CE-035 |

Q. What are you recommending to the Commission regarding the sales forecast in this case?

A. I am recommending that the Commission order the Company to include all raw data and inputs used to construct the deliveries and customer count forecast models, which includes the information contained within Exhibit S-23, in all future gas rate case filings. The data contained within the exhibit was used by the Company (as inputs) to construct the econometric models used to forecast natural gas deliveries. In each subsequent rate case, the Company should provide all of the input data used to build the sales forecasting models.

Q. Why should the Company include the model input data in subsequent rate case filings?

A. It is crucial that Staff has access to the data used to build the forecasts, in order to better understand the modeling choices and methodologies used to forecast

natural gas deliveries. If the Company includes the most current iteration of the data found in my exhibit with each rate case application, Staff will not have to procure the data via audit as was done in this instant case, saving time and allowing for more effective analysis of the forecast. Taken together with the other sales forecast specific filing attachments, Staff will be able to effectively recreate the Company's forecast models, in order to ensure that the forecast of natural gas deliveries is the most accurate estimate of future consumption to be used as a rate determinant.

Q. Does this conclude your testimony at this time?

A. Yes.

MS. STIRLING: Staff calls to be filed the qualifications and direct testimony of Nicholas Revere that consists of a cover sheet and nine pages of questions and answers. Mr. Revere sponsored one exhibit associated with his direct testimony. This exhibit has been marked Exhibit S-21. Mr. Revere also sponsored rebuttal testimony consisting of nine pages of questions and answers.

Staff moves to bind into the record the qualifications, direct, and rebuttal testimony of Nicholas Revere.

JUDGE VARCHETTI: All right.

MS. STIRLING: And to admit the associated exhibit, Your Honor. And to admit the associated exhibits.

JUDGE VARCHETTI: All right. Are there any objections to binding in the direct and rebuttal testimony of Mr. Revere or his associated exhibits?

I am hearing none, so the direct and rebuttal testimony is bound into the record, and his associated exhibits are admitted.

(Direct Testimony, Qualifications, and Rebuttal Testimony bound in)

**S T A T E  O F  M I C H I G A N**

**BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION**

*** * * ***

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|---|---|---|
| **In the matter on the application of CONSUMERS ENERGY COMPANY for authority to increase its rates for the distribution of natural gas and for other relief.** | ) ) ) ) ) | **Case No. U-21806** |

# QUALIFICATIONS AND DIRECT TESTIMONY OF

# NICHOLAS M. REVERE

# MICHIGAN PUBLIC SERVICE COMMISSION

**April 23, 2025**

**QUALIFICATIONS OF NICHOLAS M. REVERE**
**CASE NUMBER U-21806**
**PART I**

Q. Please state your name and business address.

A. My name is Nicholas M. Revere. My business address is 7109 West Saginaw Hwy, Lansing, Michigan 48917.

Q. By whom are you employed and in what capacity?

A. I am employed by the Michigan Public Service Commission (MPSC or Commission) as the Manager of the Rates and Tariff Section of the Regulated Energy Division.

Q. Would you briefly describe your academic background?

A. I earned a Bachelor of Arts degree in Political Science and a Bachelor of Arts degree in Economics from Michigan State University in 2006. In August of 2008 and 2009, I completed the annual National Association of Regulatory Utility Commissioners (NARUC) regulatory studies program at Michigan State University, which included courses on ratemaking, rate case auditing, regulatory policy, and other regulatory issues. In September of 2010, I completed the Institute for Public Utilities Advanced Regulatory Studies Program. In October 2012, I completed the Association of Edison Illuminating Companies' Advanced Course in Load Research.

Q. What are your current responsibilities at the MPSC?

A. As Manager of the Rates and Tariff Section, I supervise the members of and oversee the responsibilities of the section. The responsibilities of the section include, but are not limited to, analyzing utility reports, financial records, and rate case filings to determine the appropriate level of rates for regulated energy utilities, utilizing laws, regulations, and Commission policies. The section is charged with conducting MPSC Staff (Staff) Cost of Service allocation studies (COSS) and rate designs for gas and electric utilities and reviewing special contracts, gas storage rates, and Act 9 intrastate pipeline rates. The



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section is also involved in customer complaint and inquiry processing, updating electric and gas comparison spreadsheets for the MPSC website, and tariff administration.

Q. Have you previously filed testimony in any cases before the Commission?

A. Yes. I filed testimony in the following cases:

| Case | Company | Case Type |
|---|---|---|
| U-15645 | Consumers Energy Electric | Rate Case |
| U-15766 | MichCon Gathering v. Highmount | Act 9 Complaint |
| U-15768 | Detroit Edison/DTE Electric | Rate Case |
| U-15985 | MichCon/DTE Gas | Rate Case |
| U-15986 | Consumers Energy Gas | Rate Case |
| U-16169 | SEMCO Energy Gas | Rate Case |
| U-16191 | Consumers Energy Electric | Rate Case |
| U-16566 | Consumers Energy Electric | RDM Recon |
| U-16568 | Upper Peninsula Power Company | RDM Recon |
| U-16780 | Detroit Edison/DTE Electric | RDM Recon |
| U-16830 | Wisconsin Electric Power Company | Rate Case |
| U-16952 | Detroit Edison/DTE Electric | ECIM Recon |
| U-16999 | MichCon/DTE Gas | Rate Case |
| U-17643 | Consumers Energy Gas | Rate Case |
| U-17688 | Consumers Energy Electric | Act 169 |
| U-17689 | Detroit Edison/DTE Electric | Act 169 |
| U-17701 | MichCon/ DTE Gas | IRM |
| U-17735 | Consumers Energy Electric | Rate Case |

**QUALIFICATIONS OF NICHOLAS M. REVERE**
**CASE NUMBER U-21806**
**PART I**

| | | | |
|---|---|---|---|
| 1 | U-17767 | Detroit Edison/DTE Electric | Rate Case |
| 2 | U-17882 | Consumers Energy Gas | Rate Case |
| 3 | U-17990 | Consumers Energy Electric | Rate Case |
| 4 | U-18010 | Consumers Energy Gas | Contract |
| 5 | U-18014 | Detroit Edison/DTE Electric | Rate Case |
| 6 | U-18124 | Consumers Energy Gas | Rate Case |
| 7 | U-18224 | Upper Michigan Energy Resources Corporation | CON |
| 8 | U-18239 | Consumers Energy Electric | SRM |
| 9 | U-18248 | Detroit Edison/DTE Electric | SRM |
| 10 | U-18250 | Consumers Energy Electric | Securitization |
| 11 | U-18253 | Upper Michigan Energy Resources Corporation | SRM |
| 12 | U-18254 | Upper Peninsula Power Company | SRM |
| 13 | U-18255 | Detroit Edison/DTE Electric | Rate Case |
| 14 | U-18258 | Cloverland Electric Cooperative | SRM |
| 15 | U-18322 | Consumers Energy Electric | Rate Case |
| 16 | U-18370 | Indiana Michigan Power Company | Rate Case |
| 17 | U-18999 | DTE Gas | Rate Case |
| 18 | U-20111 | Upper Peninsula Power Company | TCJA Credit A |
| 19 | U-20114 | Michigan Gas Utilities | TCJA Credit A |
| 20 | U-20130 | Upper Michigan Energy Resources Corporation | SRM |
| 21 | U-20131 | Upper Peninsula Power Company | SRM |
| 22 | U-20144 | Cloverland Electric Cooperative | SRM |
| 23 | U-20162 | DTE Electric | Rate Case |



VERITEXT LEGAL SOLUTIONS

**QUALIFICATIONS OF NICHOLAS M. REVERE**
**CASE NUMBER U-21806**
**PART I**

| | | | |
|---|---|---|---|
| 1 | U-20189 | DTE Gas | TCJA Credit B |
| 2 | U-20276 | Upper Peninsula Power Company | Rate Case |
| 3 | U-20284 | DTE Electric | TCJA Credit B |
| 4 | U-20298 | DTE Gas | TCJA Calculation C |
| 5 | U-20309 | Consumers Energy | TCJA Calculation C |
| 6 | U-20316 | Indiana Michigan Power Company | TCJA Credit B |
| 7 | U-20317 | Indiana Michigan Power Company | TCJA Calculation C |
| 8 | U-20322 | Consumers Energy Gas | Rate Case |
| 9 | U-20233 | Consumers Energy Gas | GCR Plan |
| 10 | U-20359 | Indiana Michigan Power Company | Rate Case |
| 11 | U-20479 | SEMCO Energy Gas | Rate Case |
| 12 | U-20561 | DTE Electric | Rate Case |
| 13 | U-20642 | DTE Gas | Rate Case |
| 14 | U-20650 | Consumers Energy Gas | Rate Case |
| 15 | U-20150 | CARE v. Upper Peninsula Power Company | Complaint |
| 16 | U-20697 | Consumers Energy Electric | Rate Case |
| 17 | U-20889 | Consumers Energy Electric | Securitization |
| 18 | U-20940 | DTE Gas | Rate Case |
| 19 | U-20963 | CE Electric | Rate Case |
| 20 | U-21148 | Consumers Energy Gas | Rate Case |
| 21 | U-20836 | DTE Electric | Rate Case |
| 22 | U-21224 | Consumers Energy Electric | Rate Case |
| 23 | U-21286 | Upper Peninsula Power Company | Rate Case |

**QUALIFICATIONS OF NICHOLAS M. REVERE**
**CASE NUMBER U-21806**
**PART I**

| | | | |
|---|---|---|---|
| 1 | U-21308 | Consumers Energy Gas | Rate Case |
| 2 | U-21297 | DTE Electric | Rate Case |
| 3 | U-21389 | Consumers Energy Electric | Rate Case |
| 4 | U-21461 | Indiana Michigan Power Company | Rate Case |
| 5 | U-21384 | DTE Gas | Depreciation |
| 6 | U-21291 | DTE Gas | Rate Case |
| 7 | U-21490 | Consumers Energy Gas | Rate Case |
| 8 | U-21540 | Michigan Gas Utilities | Rate Case |
| 9 | U-21555 | Upper Peninsula Power Company | Rate Case |
| 10 | U-21534 | DTE Electric | Rate Case |
| 11 | U-21585 | CE Electric | Rate Case |
| 12 | U-21816 | CE Electric | REP Case |



VERITEXT LEGAL SOLUTIONS

Q. What is the purpose of your testimony in this case?

A. The purpose of my testimony is to support Staff's proposed allocation of FERC Account 378 as well as the calculation of the associated composite allocator.

Q. Are you sponsoring any exhibits?

A. Yes, I am sponsoring the following exhibit:

Exhibit S-21.0, STAFF FERC Account 378 Composite Allocator Calculation

**FERC Account 378 Allocation**

Q. What does Consumers Energy (the Company) witness Samuel M. Geller propose with regard to the treatment of other distribution plant?

A. Based on the review of other distribution plant conducted by the Company as a result of the settlement agreement in its previous natural gas rate case, MPSC Case No. U-21308, Company witness Geller proposes splitting other distribution into the constituent Federal Energy Regulatory Commission (FERC) accounts so that they may each be allocated separately.[1]

Q. What does Company witness Geller propose for FERC Account 378, Measuring and Regulating Station Equipment?

A. Company witness Geller proposes allocating FERC Account 378 using Allocator 104, which includes annual usage and peak usage for customers served at all pressure levels, claiming that the costs recorded in this account are associated with equipment that is "critical to the safe and reliable operations of the Company's distribution system" and thereby "benefit all customers."[2]

[1] Company witness Geller Direct Testimony, pp. 8-10.
[2] *Id.*

Q. Did the Company perform any additional analysis on FERC Account 378 as a result of the U-21308 settlement?

A. Yes. As described by Company witness Geller, the Company also performed a more detailed analysis of the costs in FERC Account 378, which included identifying costs associated with measuring and regulating stations serving different pressure levels.[3] The results of this analysis were provided as Exhibit A-57.

Q. What does allocation does Staff propose for FERC Account 378?

A. Staff proposes using a composite allocator that weights allocators (determined appropriate for each category in the detailed analysis provided by the Company) by the amount of costs in those categories, calculated on Exhibit S-21.0. Staff agrees with the Company that Allocator 104 is appropriately applied to the two "All Other Costs" categories (Huron Compressor Station and Odorization) which represent approximately 14% of the total, as no evidence has been provided showing those costs are associated with any given pressure level directly. For Measuring and Regulator Stations, which represent approximately 86% of the total, Staff utilized the allocators associated with the pressure level served in proportion to the amount of costs. For example, 9.89% of the Measuring and Regulator Stations cost is identified as associated with stations serving the high-pressure distribution system, so the amount of the composite allocator which allocates on the basis of Allocator 105, the HP average and peak (A&P) allocator, is 9.89% * 86.07%, or approximately 8.51%. It is Staff's position that this composite allocator best determines how the costs in FERC Account 378 should be allocated based

[3] Company witness Geller Direct Testimony, pp. 12-14.

on the information provided by the Company about which costs are associated with each serving each pressure level. Similar to how allocation is done for distribution mains based on pressure level and electric distribution costs based on voltage level, only allocating the costs associated with a given pressure level based on determinants served at that pressure level best reflects the cost causative relationship.

Q. Why did Staff weight the allocators by cost?

A. As it is the cost being allocated, any cost difference between measuring and regulating stations serving different pressure levels is appropriate to recognize. The method utilized by Staff appropriately recognizes this difference in the weighting. To utilize the number or share of the stations would fail to take into account these cost differences and would thereby fail to properly reflect cost-causation.

Q. How was Staff's recommended composite allocator applied?

A. I provided the composite allocator to Staff witness Kevin S. Krause, who then applied it to FERC Account 378 in Staff's proposed cost-of-service study (COSS).

Q. What is the impact of Staff's proposal compared to the Company's?

A. Staff's proposal results in a shift of approximately $22.6 million of plant balance from transportation customers to sales customers, the details of which are shown on Exhibit S-21.0. It is important to note that the revenue requirement impact of the shift will be substantially less, as the revenue requirement change will be the plant change net of the accumulated depreciation change multiplied by the overall rate of return plus the depreciation change.

Q. Please summarize your recommendations.

A. My recommendations are as follows:

1. The Commission should approve the calculation and application of Staff's proposed composite allocator for FERC Account 378.

Q. Does this conclude your testimony?

A. Yes, it does.

**S T A T E  O F  M I C H I G A N**

**BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION**

*** * * ***

| | | |
|---|---|---|
| **In the matter on the Application of CONSUMERS ENERGY GAS COMPANY for authority to increase its rates for the distribution of natural gas and for other relief.** | ) ) ) ) ) | **Case No. U-21806** |

# REBUTTAL TESTIMONY OF

# NICHOLAS M. REVERE

# MICHIGAN PUBLIC SERVICE COMMISSION

**May 14, 2025**

Q. Are you the same Nicholas M. Revere that filed direct testimony in the instant case?

A. Yes, I am.

Q. What is the purpose of your rebuttal testimony in this case?

A. The purpose of my rebuttal testimony is to present Staff's analysis of and/or position on certain proposals made by Lansing Board of Water & Light and Michigan State University (LBWL/MSU collectively) witness Timothy S. Lyons regarding the appropriate treatment of certain Other Distribution Plant accounts and Association of Businesses Advocating Tariff Equity (ABATE) witness Jessica A. York regarding allocation of distribution mains, revenue allocation, and rate design.

Q. Are you sponsoring any exhibits with your rebuttal testimony?

A. No.

**"Other Distribution" Costs**

Q. LBWL/MSU witness Lyons claims that accounts 374-378 in Other Distribution plant should be "functionalized" between high-pressure (HP) and non-HP using a Company workpaper.[1] Does Staff agree?

A. No. The proportion of the costs in accounts 374-377 that are associated with transmission, HP, and non-HP mains is unknown, as it is Staff's understanding that the Company does not have records on which pressure level the items in these Other Distribution Plant accounts are installed or associated with. The proposed "functionalization" effectively assumes that the costs in these Other Distribution plant accounts are distributed between HP and non-HP mains in proportion to the costs of mains in each category, as that is what the Company workpaper does. No evidence was

[1] LBWL/MSU witness Lyons Direct, pp. 19-21.

presented that would support this assumption. Therefore, the proposal should be rejected for these accounts. For account 378, however, relying on this proxy for cost distribution between the categories would be equally inappropriate but is unnecessary, as the Company was able to produce the cost information necessary to determine what proportion of costs for the metering and regulating stations within account 378 are appropriate to allocate to customers at each pressure level. Staff proposed using this information directly in my direct testimony, which results in a more accurate match of costs to their causation than that proposed by LBWL/MSU witness Lyons. For the reasons discussed above as well as in my direct testimony, LBWL/MSU witness Lyons' proposal should be rejected and Staff's treatment of these accounts should be approved.

**Distribution Mains Allocation**

Q. What does ABATE witness York state with regard to the cost causation of gas mains?

A. ABATE witness York states "[t]he Company has clearly demonstrated that its T&D main capacity is designed to meet the natural gas demand of all ratepayers at all times"[2] and therefore "the Design Day Demand method is most accurate from a cost-causation standpoint."[3]

Q. Does Staff agree with these statements?

A. Not entirely. While the way customers cause costs on gas mains does depend on designing the system to meet peak day demand, in part, it also depends on usage. Additionally, it has not been shown how exactly costs change with demand. A number of costs associated with designing and constructing the system may vary little with demand

[2] ABATE witness York Direct, p. 25.
[3] ABATE witness York Direct, p. 26

(trenching, boring, etc.) or vary more on geography (length of main, etc.) For these reasons, as well as those discussed later in my rebuttal (as well as that of Staff witness Kevin S. Krause) Staff continues to support the A&P method and ABATE witness York's claims not be considered to support the requested relief.

Q. ABATE witness York claims the A&P allocation method is flawed as it "double-counts" the average usage that occurs on the peak day, further claiming that the A&E method avoids this flaw.[4] Does Staff agree?

A. No. ABATE witness York proposes using the Company's Version 3 of the COS, which uses the A&E method that utilizes monthly class non-coincident peaks (NCP) for the share of design peak day by class.[5] ABATE witness York provides no support for why class NCP is appropriately considered a cost causative element other than it does not result in an allocation equivalent to coincident peak demand,[6] and for that reason alone the allocation method should be rejected. The A&E method proposed by ABATE witness York also fails to properly recognize usage of the system and the appropriate allocation of costs in much the same way as the A&E method using class contributions to design peak day, with the additional failing of using a measure that has not been shown to have any connection to cost causation. It also breaks the link between system load factor, peak, and usage that the A&P method relies on. Staff is uncertain what the justification for using system load factor for weighting is when the peak used to calculate that load factor is no longer part of the equation, as ABATE witness York provides none. The A&P method does properly recognize usage of the system and the appropriate allocation

[4] ABATE witness York Direct, p. 26.
[5] ABATE witness York Direct, p. 27.
[6] *Id.*

of costs, as further discussed by Staff witness Kevin S. Krause. Both A&E methods also fail to recognize that delivering the "average" amount of gas on a peak day (or during a class' NCP month) does not result in the same costs as on an average day. They also fail to recognize that average usage is really another way of incorporating throughput, or the entirety of gas used throughout the year, of which the average used on one of the days of the year represents an exceedingly small portion, thereby overcorrecting a problem that does not exist in the first place. These are further reasons the claimed "double-count" does not exist. Even if it could be said to, the actual effect is minimal (as further discussed by Staff witness Krause) and the change to either A&E method is not justified thereby.

Q. ABATE witness York claims that A&E "is more reflective of cost-causation" because it "assigns greater cost responsibility to gas deliveries that are more variable due to weather sensitivity or other factors".[7] Does Staff agree?

A. No. First, this claim relies on accepting that the A&E method more accurately reflects the appropriate allocation of costs, which for the reasons discussed above and in Staff witness Krause's testimony it does not. By using both design peak and throughput by class, weighted by load factor, the A&P allocator does a better job than the A&E method reflecting the variability in load between classes. In effect, the argument relies on the assumption that, even though the system is built to serve load both on peak (or during any given class' peak month) and at every other time of year, customers should pay as if the system was built only to serve them and their load shape. This would be inappropriate; in fact, under such conditions, the system would likely not exist at all. For all of the

[7] ABATE witness York Direct, p. 26.

foregoing reasons, the proposed replacement of the A&P allocator with the A&E allocator would less accurately reflect use of the system and should be rejected.

**Revenue Allocation**

Q. What does ABATE witness York claim with regard to the allocation of class revenue responsibility?

A. ABATE witness York claims the Company's "proposed revenue apportionment is generally based on the results of its Preferred CCOSS, the proposed revenue apportionment actually increases the revenue requirement for Rate ST, Rate LT, and Rate XLT" compared to the results of the COS.[8] Staff witness Nancy C. Rademacher clarifies why this is the case in rebuttal; in short, the vast majority of the difference is related to the allocation of two items that occur outside of the COS, not shifting money between the transportation class and sales class or between transportation rate schedules. ABATE witness York further claims the Company's proposal does not "sufficiently reflect an equitable revenue apportionment."[9]

Q. What does ABATE witness York recommend as an "equitable revenue apportionment"?

A. ABATE witness York proposes a revenue spread that is claimed to consider both the results of the A&E and A&P COSs and "makes a gradual but meaningful movement toward cost of service, and ensures that no class receives an increase greater than 1.6 times the system average."[10]

Q. Does ABATE witness York explain why limiting the increase is "more equitable"?

[8] ABATE witness York Direct, p. 14.
[9] ABATE witness York Direct, p. 16.
[10] ABATE witness York Direct, p. 16.

A. No. An equitable revenue apportionment, in Staff's view, is one that properly reflects the allocation of costs, which ABATE witness York's proposal fails to do in a number of respects. First, by using the A&E method, which does not appropriately reflect cost causation as discussed earlier and in the rebuttal testimony of Staff witness Krause. Second, by arbitrarily lowering the increase to the transportation class and shifting revenue responsibility to the sales class (and amongst the transportation rate schedules). It also appears that ABATE witness York arbitrarily determined whether the results of the A&P or A&E COS was more appropriate on which to base the recommended revenue for any given class or schedule given the lack of justification given for these decisions.

Q. ABATE witness York claims the proposal is supported by the Commission's decision in DTE Gas' most recently decided rate case.[11] Does Staff agree?

A. No. Rather than resulting in moving "classes toward a more rational revenue allocation based on a more accurate measure of class cost of service,"[12] it relies on an incorrect COS that does not reflect cost-causation, and then ignores even that when it benefits the transportation customers at the expense of sales customers. Staff's position is that this is inequitable, and also fails to accomplish the same goals as the Commission had in DTE Gas' case.

Q. What, then, does Staff recommend?

A. As discussed further in the rebuttal of Staff witness Rademacher, Staff recommends that the allocation of revenue responsibility amongst the classes follow the approved COSS (which should be that proposed by Staff), with modifications as necessary to maintain

[11] ABATE witness York Direct, p. 17.
[12] *Id.*

breakevens[13] (which were unnecessary for the transportation class in Staff's rate design proposal in its direct case) and result in reasonable rate design.

**Rate Design**

Q. In discussing the appropriate rate design for the transportation class, ABATE witness York discusses how rate shifting is the reason for the manner in which transportation rates are designed.[14] Does Staff agree?

A. Not entirely. The purpose of the breakeven points is not just to minimize rate shifting, though that is one of the reasons for maintaining them. Traditionally, the customer charges for the transportation rates have been set only to maintain the breakevens, and have not relied on a cost-based calculation, though it has been a consideration for ST (as well as contiguous customer charges). Rate XXLT has its customer charge set using the cost-based calculation as well, as the schedule is only available to customers using a very large amount of gas; above 4,000,000 Mcf. For the other transportation schedules, however, the delineations between them are effectively arbitrary (though they may initially have had some justification when put in place); the schedules are defined as they are due to the breakeven points, not due to any consideration of differential use of the system as they are for, say, electric distribution rates. Customers can freely move between rate schedules, likely based on which one is most beneficial. Any change to the breakevens (by basing customer charges on some calculation of cost-basis, for example) would necessitate a determination of which customers are likely to move based on the change, and redoing all determinants, associated allocations, and appropriate rate design

[13] Breakeven points being the amount of usage at which the bills under two different rates are the same.
[14] ABATE witness York Direct, pp. 36-37.

unless the breakevens locked customers into a schedule. Locking the breakevens in place and not allowing customer movement would also effectively undermine the schedule definitions which are based on those very breakevens, rendering the schedules' arbitrariness fixed without reason. A reconfiguration of the transportation schedules to be based on something other than the breakeven points themselves has not been proposed in the instant case. For these reasons, Staff has not based its proposed customer charges for ST, LT, and XLT on anything other than maintaining the breakevens and attempting to minimize changes to and differences between the customer charges and distribution rates for each schedule in the instant case. The method of rate design proposed by ABATE witness York fails to either lock the breakevens in place or move determinants appropriately, and should be rejected for that reason. It has also not been shown that the current rate schedule delineations are justified by differential use of the system. ABATE witness York further attempts to support the proposal by showing how rare it is for customers to switch rates.[15] What ABATE witness York fails to acknowledge is that this minimal rate switching is mainly a result of past rate designs *being done in such a way so as to minimize rate switching.* Using the fact that such considerations have been successful in minimizing rate switching should not be considered as evidence that such considerations are unnecessary; in fact, it is evidence that they should continue to be utilized. The Commission should approve rate design based on the method used by the Company and Staff for the reasons discussed above, as well as those discussed by Staff witness Rademacher in direct and rebuttal testimony.

[15] ABATE witness York Direct, pp. 37-38.

**Summary**

Q. Please summarize your recommendations.

A. My recommendations are as follows:

1. The Commission should reject the proposals to modify the allocation of certain Other Distribution Plant accounts put forward by LBWL/MSU witness Lyons in the instant case and approve Staff's proposed treatment of these accounts.

2. The Commission should reject the replacement of the A&P allocator with the A&E allocator and approve use of the A&P allocation methods.

3. The Commission should base the allocation of revenue responsibility amongst the classes follow the approved COSS and other cost allocations with modifications as necessary to maintain breakevens and result in reasonable rate design

4. The Commission should base rate design on Staff and the Company's proposed method, rejecting that proposed by ABATE witness York.

Q. Does this conclude your testimony?

A. Yes, it does.

MS. STIRLING: Staff calls to be filed the qualifications and rebuttal testimony of Fawzon Tiwana that consists of a cover sheet and four pages of questions and answers.

Mr. Tiwana did not sponsor direct testimony, nor did he sponsor any exhibits associated with his testimony -- his rebuttal testimony.

So the Staff moves to bind into the record the qualifications and rebuttal testimony of Fawzon Tiwana.

JUDGE VARCHETTI: All right. Are there any objections to binding in the testimony, the rebuttal testimony, of Mr. Tiwana?

Hearing none, then, the testimony is bound into the record.

(Rebuttal Testimony and Qualifications bound in)

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

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| | | |
|---|---|---|
| In the matter of the application of<br>**CONSUMERS ENERGY COMPANY**<br>for authority to increase its rates for the<br>distribution of natural gas and for other relief. | )<br>)<br>)<br>)<br>) | Case No. U-21806 |

**QUALIFICATIONS AND REBUTTAL TESTIMONY OF**

**FAWZON B. TIWANA**

**MICHIGAN PUBLIC SERVICE COMMISSION**

**May 14, 2025**

**QUALIFICATIONS OF FAWZON B. TIWANA**
**CASE NUMBER U-21806**
**PART I**

Q. Please state your name, business address, and occupation.

A. My name is Fawzon B. Tiwana, and my business address is 7109 W. Saginaw, Lansing, MI 48917. I am employed by the Michigan Public Service Commission (MPSC or Commission) as an Economic Specialist in the Energy Optimization (EO) Section of the Energy Resources Division.

Q. Please describe your education and professional background.

A. I graduated from Wayne State University in 2017 with a Bachelor of Arts in Economics. I was hired by the Michigan Public Service Commission in 2018 as an Economic Analyst in the Energy Waste Reduction (EWR) Section (now known as the EO Section). I have attended the Institute of Public Utilities Regulatory Studies Program in East Lansing, MI and Midwest Energy Efficiency Alliance's Midwest Energy Solutions Conference on multiple occasions.

Q. What are your responsibilities as an Economic Specialist?

A. My current responsibilities include, but are not limited to, reviewing EWR Annual Plan filings/reports to ensure the plans meet the requirements established by Public Act 295 of 2008, as amended by Public Act 229 of 2023. I also case coordinate and review EWR Biennial Plan filings/amendments and assist with the MPSC EWR Low Income Workgroup. Additionally, I am the lead technical analyst and serve as the key witness for the annual reconciliation process of all Revenue Decoupling Mechanism (RDM) cases filed before the Commission. I serve on the internal staff Demand Response Team and am the Michigan Renewable Energy Certification System (MIRECS) EWR credit tracking administrator. I am also responsible for the collection and tracking of EWR data and statistics.



VERITEXT LEGAL SOLUTIONS

**QUALIFICATIONS OF FAWZON B. TIWANA**
**CASE NUMBER U-21806**
**PART I**

Q. Have you ever testified before the Michigan Public Service Commission?

A. Yes, I have filed testimony in the following cases:

| Case No. |
| --- |
| U-20322 |
| U-20350 |
| U-20367 |
| U-20479 |
| U-20359 |
| U-20374 |
| U-20591 |
| U-20704 |
| U-20940 |
| U-20867 |
| U-20883 |
| U-20877 |
| U-21193 |
| U-21389 |
| U-21461 |

**REBUTTAL TESTIMONY OF FAWZON B. TIWANA**
**CASE NUMBER U-21806**
**PART II**

Q. What is the purpose of your rebuttal testimony?

A. The purpose of my rebuttal testimony is to address Michigan Environmental Council (MEC) and Sierra Club (SC) witness Alice Napoleon's testimony regarding Energy Waste Reduction (EWR) programming and incentives.

Q. Did you file initial testimony in this case?

A. No, I did not file direct testimony in this case. My first appearance in this proceeding is through this rebuttal testimony.

Q. Are you sponsoring any exhibits?

A. No.

Q. Does MEC and SC witness Napoleon recommend changes to EWR programs in this docket?

A. Yes.

Q. Are changes to Energy Waste Reduction programming best addressed in this Rate Case?

A. No. Staff does not agree that this rate case docket is the appropriate venue for recommending changes to EWR and Efficient Electrification (EFEL) program design. EWR and EFEL programming are addressed within legislatively mandated Energy Optimization Proceedings. This ensures that these programs are developed, evaluated, and implemented within a consistent framework, avoiding overlap with unrelated cases.

Q. What is Staff's recommendation?

A. Staff asserts that all recommendations and changes related to EWR and EFEL programs are not appropriate or relevant to this case. Staff recommends the



VERITEXT LEGAL SOLUTIONS

Commission find Energy Optimization Plan proceedings are the appropriate venue to recommend changes to EWR and EFEL programs.

Q. Does this conclude your testimony?

A. Yes.

MS. STIRLING: Finally, Staff moves to admit one hearing room exhibit in lieu of cross-examination. This exhibit consists of one discovery response and has been marked Exhibit S-25. This exhibit has been circulated to all parties and uploaded to the Sharepoint site associated with this case.

JUDGE VARCHETTI: All right. Are there any objections to the admission of Exhibit S-25?

I am hearing none, so Exhibit S-25 is admitted.

MS. STIRLING: Thank you, Your Honor. That concludes Staff's direct case.

JUDGE VARCHETTI: Thank you.

And as I am reviewing my notes, then, I believe that Staff is the last party that had an evidentiary presentation to make, such that the presentation of witnesses and the presentation of exhibits for admission is now complete.

Does anyone have any reason to dispute that? Has anyone missed anything? Do we need to go back and try to add in any other testimony or any other exhibits?

Looks like everyone is not raising their hand, so it appears that that is complete, then.

All right. Are there any other

housekeeping issues, then, that we might need to take up now that we are at the end?

Yes. Mr. Bzdok?

MR. BZDOK: Yeah. I wanted to talk about transcript timing.

JUDGE VARCHETTI: Certainly. Do you want to talk about that on the record or perhaps we should go off the record for that?

MR. BZDOK: Off the record.

JUDGE VARCHETTI: All right. Let's go off the record, then.

(At 11:23 AM, recess was taken)

(At 11:37 AM, proceedings resume)

JUDGE VARCHETTI: Okay. We are back on the record after just taking a short break.

It appears that we have concluded with the evidentiary presentations in this case, so the evidentiary presentations are over, and this hearing is almost ready to conclude.

I would just like to note before we leave, there are just two quick matters I wanted to bring up. One is settlement under Rule 431 of practice and procedure before the Commission. It states that all parties to proceedings before the Commission are encouraged to enter into settlements when possible.

It's my understanding that parties typically do engage in settlement discussions. What I ask is that if it becomes clear that a settlement is likely, please let me know as soon as possible.

And last, but not least, regarding briefing, since I have you all here, I ask that the briefs that you choose to submit should be brief, at least as brief as possible. If you feel that the disputed issue has been adequately addressed in direct testimony or rebuttal testimony, please do direct me to that testimony with the citation, but there is no need to simply copy and paste content from testimony directly into the brief or to simply rehash what's already been said. You can direct me to that, and that is sufficient, in my mind. So that is my request with regards to briefs.

With that being said, are there any other matters we may have to discuss on the record today?

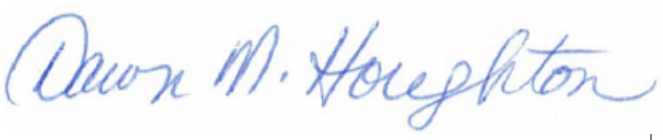
I am hearing none, so in that case, this hearing is now over and adjourned. Thank you all. I appreciate it. I appreciate your coming out today. And we are now concluded and off the record.

(At 11:38 AM, the hearing was concluded)

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C E R T I F I C A T E

I, Dawn M. Houghton, CSR-3071, do hereby certify that I reported in stenotype, via Microsoft Teams, the proceedings had in the within-entitled matter, that being Case No. U-21806, before James M. Varchetti, Administrative Law Judge with MOAHR, for the Michigan Public Service Commission, Lansing, Michigan, on Monday, June 2, 2025; and do further certify that the foregoing transcript, consisting of Volume IV, Pages 523-2778, is a true and correct transcript of my stenotype notes.



Dawn M. Houghton, CSR, RPR
Michigan License CSR-3071
Certified Shorthand Reporter
Registered Professional Reporter
Missouri License 1495
Illinois License 084.004881
Wisconsin License 20109559
Oregon License 20-0469
Notary Public
My commission expires: 7-17-2029

Dated: June 3, 2025

(NOTE: Transcript continues at page 2779 of the CONFIDENTIAL RECORD)