

In The Matter Of:
U-21870

U-21870 Transcript v6 Cross Exam 11.10.25
November 10, 2025



**SYNERGY
LITIGATION
SERVICES**

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 generation and
distribution of electricity and
for other relief

Case No.

No-21870

Volume 6

Public Record

Proceedings held via Microsoft Teams in the
Above-entitled matter before Jonathan Thoits,
Administrative Law Judge with MOAHR for the Michigan
Public Service Commission, Lansing, Michigan, on
Monday, November 10, 2025, at 10:00 a.m.

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1 (On the record at 10:00 a.m.)

2 JUDGE THOITS: We are on the record in Case U-
3 21870. Titled In the Matter of the Application of
4 Consumers Energy Company for Authority to Increase its
5 Rates for the Generation and Distribution of Electricity
6 and for Other Relief. This is the date and time for the
7 continuation of the hearing in this case. My name is John
8 Thoits. I'm the presiding officer. This hearing is being
9 held by video and audio conference.

10 Can we have appearances, please first on behalf
11 of Consumers Energy?

12 MR. TOTORAITIS: Yes, Your Honor. Bret
13 Totoraitis on behalf of Consumers Energy Company, and I am
14 also entering appearances on behalf of Gary Gensch, Anne
15 Uitvlugt, Spencer Sattler, and Evan Keimach.

16 JUDGE THOITS: Thank you. Do we have an
17 appearance on behalf of the Michigan Public Service
18 Commission Staff?

19 MR. SONNEVELDT: Good morning. I'd like to
20 enter the appearance of myself, Daniel Sonneveldt, along
21 with the appearances of Amit Singh, Alena Clark, Nicholas
22 Taylor, Adam Cozort, and Mike Orris.

23 JUDGE THOITS: Thank you. Do we have an
24 appearance on behalf of the Michigan Attorney General?

25 MS. GILL: Yes. Good morning, Your Honor.

1 Celeste Gill, on behalf of Attorney General Dana Nessel.
2 Also appearing in this case, Lucas Wollenzien and Michael
3 Moody.

4 JUDGE THOITS: Thank you. Do we have an
5 appearance on behalf of ABATE?

6 MR. CAMPBELL: Morning, Your Honor. Steve
7 Campbell, Clark Hill, PLC on behalf of the Association of
8 Businesses Advocating Tariff Equity.

9 JUDGE THOITS: Thank you. Do we have an
10 appearance on behalf of Citizens Utility Board of
11 Michigan, Michigan Environment Council, Natural Resource
12 Defense Council, and Sierra Club?

13 MS. BZDOK: Good morning, Your Honor.
14 Christopher Bzdok, along with Tracy J, TJ Andrews, and
15 Holly Hillyer on behalf of those parties.

16 JUDGE THOITS: Thank you. Do we have an
17 appearance on behalf of the Clean Energy Organizations?

18 MS. DUCKWORTH: Good morning, Your Honor. Katie
19 Duckworth on behalf of the Ecology Center, the
20 Environmental Law & Policy Center, the Union of Concerned
21 Scientists and Vote Solar. Collectively, the Clean Energy
22 Organization.

23 JUDGE THOITS: Thank you. Do we have have an
24 appearance on behalf of Energy Michigan?

25 MR. OOMS: Good morning, Your Honor. Justin

1 Ooms, this morning on behalf of Energy Michigan.

2 JUDGE THOITS: Thank you. Do we have an
3 appearance on behalf of Foundry Association of Michigan?

4 MR. OOMS: Yes, Your Honor. Justin Ooms, also
5 appearing on behalf of the Foundry Association of
6 Michigan. Excuse me.

7 JUDGE THOITS: Do we have an appearance on Great
8 Lakes Renewable Energy Association?

9 Do we have an appearance on behalf of Hemlock
10 Semiconductor Operations and Solar Technology?

11 Do we have an appearance on behalf of Kroger?

12 MR. BOEHM: Good morning, Your Honor. Kurt
13 Boehm appearing on behalf of the Kroger Company.

14 JUDGE THOITS: Thank you. Do we have an
15 appearance on behalf of Michigan Electric Transmission
16 Company?

17 MR. KLUZAK: Yes, Your Honor. Josh Kluzak on
18 behalf of Michigan Electric Transmission Company. I would
19 also like to enter the appearance of Richard Aaron,
20 Courtney Kissel, Olivia Flower, and Hanna Buzolits. Thank
21 you.

22 JUDGE THOITS: Thank you. Do we have an
23 appearance on behalf of Michigan Energy Innovation
24 Business Council, Institute for Energy Innovation &
25 Advanced Energy United?

1 MR. OOMS: Good morning, Your Honor. Justin
2 Ooms appearing on behalf of the Michigan Energy Innovation
3 Business Council, the Institute for Energy Innovation &
4 Advanced Energy United, collectively referred to here as
5 MEIU.

6 JUDGE THOITS: Thank you. Do we have an
7 appearance on behalf of Urban Core Collective?

8 Do we have an appearance on behalf of Walmart?

9 MS. HORNE: Good morning, Your Honor. Melissa
10 Horne appearing on behalf of Walmart, Inc.

11 JUDGE THOITS: Thank you. Do we have any other
12 appearances?

13 All right. It's my understanding that there are
14 no witnesses remaining to be crossed, and all we have left
15 to do in this hearing is to bind in the testimony and
16 admit the exhibits that have yet to be bound in or
17 admitted. Is that correct?

18 MR. TOTORAITIS: That's my understanding, Your
19 Honor.

20 JUDGE THOITS: All right. Mr. Totoraitis, would
21 you like to proceed with your witness?

22 MR. TOTORAITIS: Thank you, Your Honor. The
23 last remaining witness for Consumers Energy is Richard T.
24 Blumenstock. My understanding, Your Honor, is that all
25 parties have waived cross-examination of Mr. Blumenstock

1 and are prepared to stipulate entry of his testimony and
2 exhibits into the record, subject to the decision on
3 motion to strike that you issued on Friday of last week.
4 So, with that, Your Honor, I would move to bind in the
5 direct testimony of Richard T. Blumenstock, which consist
6 of a cover page and 135 pages of questions and answers. I
7 would move to bind in the rebuttal testimony of Richard T.
8 Blumenstock, which consists of a cover page and 39 pages
9 of questions and answers. I would note that Consumers
10 Energy has provided to the court reporter and uploaded to
11 the SharePoint site the stricken version of Mr.
12 Blumenstock's rebuttal testimony that corresponds to the
13 attachment in Beck's motion to strike. Consumers Energy
14 also moves for the admission of Mr. Blumenstock's exhibits
15 as follows. Exhibit A-41 and A-42, Exhibit A-12 Schedule
16 B-5.2, which should complete the exhibit A-12 as well for
17 all company witnesses, Your Honor. Exhibits A-43, A-44,
18 A-45, A-46, A-47, A-48, A-49, A-50, A-51, A-191, A-192, A-
19 193, A-194, A-195, A-196, A-197, A-198, A-199, A-200, A-
20 201, A-204, and A-205.

21 JUDGE THOIT: All right. And just for the
22 record, as Mr. Totoraitis has indicated, there was a
23 ruling last Friday granting the motion to strike. That
24 motion to strike had an attachment with a markup showing
25 the testimony stricken, and also Exhibits A-202 and A-203

1 were stricken pursuant to that ruling. Are there any
2 objections to the admission of the testimony and the
3 exhibits for the witness?

4 Hearing none. The direct and rebuttal testimony
5 of Richard Blumenstock is bound into the record and
6 exhibits A-12, A-41 through A-51, A-191 through A-201, and
7 A-204 and A-205 are admitted.

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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 generation and distribution of)
 electricity and for other relief.)
 _____)

Case No. U-21870

DIRECT TESTIMONY

OF

RICHARD T. BLUMENSTOCK

ON BEHALF OF

CONSUMERS ENERGY COMPANY

June 2025

RICHARD T. BLUMENSTOCK
U-21870 DIRECT TESTIMONY

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

2 A. My name is Richard T. Blumenstock, and my business address is 1945 West Parnall Road,
3 Jackson, Michigan 49201.

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

5 A. I am employed by Consumers Energy Company (“Consumers Energy” or the “Company”).

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

7 A. I am currently the Executive Director of Electric Supply Engineering. I began employment
8 at the Company in May 1994 in the electric transmission planning area where I performed
9 planning studies on the Company’s distribution and transmission systems. In April 2002,
10 I was assigned to the electric operations area where I oversaw engineering operations for
11 the distribution and transmission systems. In August 2009, I was assigned to the fuel
12 supply area where I oversaw the Company’s purchasing and transport functions for fuel
13 for electric generation. In June 2011, I assumed additional responsibilities including
14 oversight of the Company’s interaction in the Midcontinent Independent System Operator,
15 Inc. (“MISO”) markets; wholesale settlements and transactions functions; Power Supply
16 Cost Recovery (“PSCR”) activities; and planning for electric supply necessary to satisfy
17 customers’ energy and capacity needs. In September 2019, I assumed the role of Executive
18 Director of Electric Planning, overseeing the company-wide efforts for all electric
19 planning. In September 2022, I assumed my current position as Executive Director of
20 Electric Supply Engineering.

RICHARD T. BLUMENSTOCK
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1 **Q. What are your responsibilities as Executive Director of Electric Supply Engineering?**

2 A. My responsibilities as Executive Director of Electric Supply Engineering include oversight
3 of all activities associated with planning and design for the Company's electric generation
4 portfolio.

5 **Q. What is your formal educational experience?**

6 A. I received a Bachelor of Science degree in 1992 and a Master of Science degree in 1994,
7 both in Electrical Engineering from Michigan Technological University.

8 **Q. Have you previously provided testimony before the Michigan Public Service
9 Commission ("MPSC" or the "Commission")?**

10 A. Yes, I provided testimony in the following MPSC cases:

- 11 • Case No. U-16045-R: Reconciliation of PSCR Costs and Revenues for the
12 Calendar Year 2010;
- 13 • Case No. U-16432-R: Reconciliation of PSCR Costs and Revenues for the
14 Calendar Year 2011;
- 15 • Case No. U-16890: Approval of a PSCR Plan and for Authorization of Monthly
16 PSCR Factors for the Year 2012;
- 17 • Case No. U-16890-R: Reconciliation of PSCR Costs and Revenues for the
18 Calendar Year 2012;
- 19 • Case No. U-17429: Approval of a Certificate of Necessity for the Thetford
20 Generating Plant pursuant to MCL 460.6s and for related accounting and
21 ratemaking authorizations;
- 22 • Case No. U-17317: Approval of a PSCR Plan and for Authorization of Monthly
23 PSCR Factors for the Year 2014;
- 24 • Case No. U-17317-R: Reconciliation of PSCR Costs and Revenues for the
25 Calendar Year 2014;
- 26 • Case No. U-17752: Authority to amend its renewable energy plan approved in
27 Case Nos. U-15805, U-16543, U-16581, and U-17301;
- 28 • Case No. U-17678: Approval of a PSCR Plan and for Authorization of Monthly
29 PSCR Factors for the Year 2015;

RICHARD T. BLUMENSTOCK
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- Case No. U-17678-R: Reconciliation of PSCR Costs and Revenues for the Calendar Year 2015;
- Case No. U-18250: Application of Consumers Energy for a financing order approving the securitization of qualified costs and related approvals associated with the early termination of the Palisades Nuclear Energy Plant Power Purchase Agreement;
- Case No. U-20134: Application of Consumers Energy for authority to increase its rates for the generation and distribution of electricity and for other relief;
- Case No. U-20165: Application of Consumers Energy for approval of its Integrated Resource Plan (“IRP”) pursuant to MCL 460.6t and for other relief;
- Case No. U-20697: Application of Consumers Energy for authority to increase its rates for the generation and distribution of electricity and for other relief;
- Case No. U-20963: Application of Consumers Energy for authority to increase its rates for the generation and distribution of electricity and for other relief;
- Case No. U-21090: Application of Consumers Energy for Approval of an IRP under MCL 460.6t, certain accounting approvals, and for other relief;
- Case No. U-21224: Application of Consumers Energy for authority to increase its rates for the generation and distribution of electricity and for other relief;
- Case No. U-21389: Application of Consumers Energy for authority to increase its rates for the generation and distribution of electricity and for other relief; and
- Case No. U-21585: Application of Consumers Energy for authority to increase its rates for the generation and distribution of electricity and for other relief.

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

A. The purpose of my direct testimony is to support the Generation Department (“Generation”) requests in this case, and to provide other information that the Company has committed to provide. Toward that end I will:

- Describe Consumers Energy’s oil-, and gas-fired generation assets, and its hydroelectric and renewable generation assets, including their projected retirement dates;
- Support the Company’s generation asset strategy to focus continued investment in those generating units (Zeeland Generating Station (“Zeeland Plant”, “ZGS” or “Zeeland”), New Covert Generating Facility (“Covert Plant” or “Covert”),

RICHARD T. BLUMENSTOCK
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and Jackson Generating Station (“Jackson Plant”, “JGS” or “Jackson”)) which provide the most long-term economic benefit for customers;

- Support the periodic outage plans and the Generation Unit Availability and Random Outage Rate (“ROR”) projections for oil- and gas-fired peaking generation, and hydroelectric power generation, for the projected test year ending April 30, 2027;
- Support the reasonableness and prudence of the capital expenditures for oil- and gas-fired peaking generation, and hydroelectric power generation for the historical test year ended December 31, 2024, the 16-month bridge period beginning January 1, 2025 and ending April 30, 2026, and the projected test year ending April 30, 2027;
- Support the reasonableness and prudence of the Operation and Maintenance (“O&M”) oil- and gas-fired peaking generation, and hydroelectric power for historical test year ended December 31, 2024, the 16-month bridge period beginning January 1, 2025 and ending April 30, 2026, and the projected test year ending April 30, 2027;
- Support the reasonableness and prudence of the O&M expenses for the D.E. Karn (“Karn”) Units 1 and 2 retention and separation incentives for the historical test year ended December 31, 2024;
- Support the reasonableness and prudence of the O&M expenses for the J.H. Campbell (“Campbell”) Units 1, 2, and 3 retention and separation incentives for the historical test year ended December 31, 2024, and the 16-month bridge period beginning January 1, 2025 and ending April 30, 2026;¹ and
- Describe the environmental regulations with which the Company’s electric generating fleet must comply.

Q. How is your direct testimony related to the direct testimony of other Company witnesses?

A. Company witness Megan L. Metz’s testimony supports the PSCR costs planned to be incurred, taking into account the periodic outages identified in Exhibit A-41 (RTB-1) and

¹ On May 23, 2025, the U.S. Department of Energy issued Order No. 202-25-3 (“DOE Order”) requiring the Company to “take all measures necessary to ensure that the Campbell Plan is available to operate” through August 21, 2025. The DOE Order also specifies that, at the conclusion of this period, the Company will be permitted “sufficient time for orderly ramp down . . . consistent with industry practices.” The Company is currently evaluating the impact of the DOE Order on its decommissioning plan and other aspects of this rate case. Until the Company is able to complete its evaluation, my testimony continues to reflect assumptions about the Campbell Plant’s retirement before the date of the DOE Order.

RICHARD T. BLUMENSTOCK
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the generating unit availability projections in Exhibit A-42 (RTB-2). Company witness Metz also supports the capacity value of the Company's generation assets for the seasonal construct in the MISO Planning Resource Auction ("PRA") in Table 2.

Company witness Thomas P. Clark supports the competitive solicitation process and timeline associated with the proposed battery energy storage system ("BESS") projected capital expenditures.

Company witness Patrick D. Daly supports the regulatory asset balances and amortization for the recovery of retention and separation expenses at Karn and Campbell sites in his direct testimony.

Company witness Heidi J. Myers supports the continued deferral of the revenue requirement for river hydroelectric generating plant ("River Hydro") capital expenditures as well as the proposed O&M deferral for River Hydro in her direct testimony.

Q. Are you sponsoring any exhibits with your direct testimony?

A. Yes, I am sponsoring the following exhibits:

Exhibit A-41 (RTB-1)	Generating Unit Periodic Outages;
Exhibit A-42 (RTB-2)	Generating Unit Availability Projections;
Exhibit A-12 (RTB-3) Schedule B-5.2	Summary of Actual and Projected Electric Capital Expenditures for the Years 2024 through April 2027;
Exhibit A-43 (RTB-4)	Summary of the Generation O&M Expense for the Years 2024 through February 2027;
Exhibit A-44 (RTB-5)	Zeeland Phase I and II Gas Turbine Upgrade Concept Approvals;
Exhibit A-45 (RTB-6)	Jackson Site Spare GSU Transformer Concept Approval;

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1	Exhibit A-46 (RTB-7)	Covert Load Commutated Inverter
2		Static Frequency Converter
3		Replacements Concept Approval;
4	Exhibit A-47 (RTB-8)	Covert Site Spare GSU Transformer
5		Concept Approval;
6	Exhibit A-48 (RTB-9)	Covert Control System Project
7		Concept Approval;
8	Exhibit A-49 (RTB-10)	Covert Units 1 through 3 Emerson
9		DCS Evergreen Concept Approval;
10	Exhibit A-50 (RTB-11)	Karn Unit 4 ID Fan Inlet Damper
11		Replacements Concept Approval;
12		and
13	Exhibit A-51 (RTB-12)	Karn Units 3 & 4 Combustion Air
14		Heater Replacement Concept
15		Approval.

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

17 A. Yes.

18 **Q. How are the following sections of your direct testimony organized?**

19 A. My direct testimony is divided into four sections. Section I will present exhibits and
 20 supporting testimony on the Company's generating assets, its generating asset strategy, and
 21 its generating asset projected performance metrics. Included in this section is a discussion
 22 on the status of the Company's River Hydro strategy and its projected impact on the
 23 Company's cost projections. Section II will describe the environmental regulations with
 24 which the Company's electric generating fleet must comply. Section III presents exhibits
 25 and supporting testimony for the historical and projected generation capital expenditures.
 26 Section IV will present exhibits and supporting testimony for the historical and projected
 27 generation O&M expense. This section will include support of the reasonableness and
 28 prudence of the O&M expenses for both the Karn Units 1 and 2 retention and separation

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incentives, the reasonableness and prudence of the O&M expenses for Campbell Units 1, 2, and 3 retention and separation incentives, and the Company's proposal for River Hydro O&M expense.

SECTION I

GENERATION ASSETS

Q. Please provide an overview of the Company's generation assets.

A. As of February 24, 2025, the Company's total projected owned generation assets for the 2025/2026 Planning Year had a Generator Verification Test Capacity ("GVTC") of 5,722 MW, comprised of the following units:

TABLE 1

RESOURCE	MICHIGAN LOCATION	IN-SERVICE DATE	AGE (years)	RETIREMENT DATE	NET GENERATING CAPABILITY (MW)
OIL OR GAS FIRED					
Covert	Covert, MI	2004	21	2040	1090
DE Karn 3	Essexville, MI	1975	50	2031	602
DE Karn 4	Essexville, MI	1977	48	2031	587
Zeeland CC	Zeeland, MI	2002	23	2041	534
Zeeland 1A	Zeeland, MI	2002	23	2041	158
Zeeland 1B	Zeeland, MI	2002	23	2041	157
Jackson	Jackson, MI	2002	23	2041	531
HYDROELECTRIC					
Alcona	Alcona County, MI	1924	101	n/a	3
Allegan	Allegan County, MI	1936	89	n/a	1
Cooke	Iosco County, MI	1911	114	n/a	7
Croton	Newaygo County, MI	1907	118	n/a	2
Five Channels	Iosco County, MI	1912	113	n/a	6
Foote	Iosco County, MI	1918	107	n/a	3
Hardy	Newaygo County, MI	1931	94	n/a	33
Hodenpyl	Wexford County, MI	1925	100	n/a	4
Loud	Iosco County, MI	1913	112	n/a	5
Mio	Oscoda County, MI	1916	109	n/a	1
Rogers	Mecosta County, MI	1906	119	n/a	2
Tippy	Manistee County, MI	1918	107	n/a	6
Webber	Ionia County, MI	1907	118	n/a	1
RENEWABLES					
Lake Winds	Mason County, MI	2012	13	2042	101
Cross Winds (Phase I)	Tuscola County, MI	2014	11	2044	231
Cross Winds (Phase II)	Tuscola County, MI	2018	7	2048	
Cross Winds (Phase III)	Tuscola County, MI	2018	7	2048	
Crescent Wind	Jonesville, MI	2021	4	2051	166
Gratiot Farms Wind	Alma, MI	2021	4	2051	150
Heartland Farms Wind Park	Ithaca, MI	2024	1	2054	200
Solar Gardens- GVSU	Grand Rapids, MI	2016	9	2046	3
Solar Gardens- WMU	Kalamazoo, MI	2016	9	2046	1
Cadillac Solar Garden	Cadillac, MI	2021	4	2051	0.5
Circuit West	Grand Rapids, MI	2019	6	2049	0.5
ENERGY STORAGE					
Ludington Units 1-6**	Ludington, MI	1973	52	2069	1138 (owned share)

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1 **Q. What does “owned share” mean when used with respect to Ludington Pumped**
2 **Storage Plant (“LPS” or “Ludington”) Units 1 through 6?**

3 A. The Company owns 51% of LPS and DTE Electric Company (“DTE”) owns the remaining
4 49%. Thus, the 1,138 MW capacity reported is 51% of the total LPS GVTC, reflecting the
5 Company’s share of ownership.

6 **Q. Do any of the Company’s owned generation units reflect retirement dates which are**
7 **different from those sponsored in the Company’s previous Electric Rate Case, Case**
8 **No. U-21585?**

9 A. No. There have been no changes to the retirement dates for the Company’s owned
10 generation units. The only change to the Company’s owned generation units was the
11 retirement of Campbell Units 1, 2 and 3 on May 31, 2025.

12 **Q. How will the Company continue to meet its load requirements with the retirement of**
13 **the Campbell units?**

14 A. The Settlement Agreement approved in the Company’s 2021 IRP reflects the replacement
15 of the Campbell unit capacity through a number of different resources including continued
16 growth of its solar generation assets, demand response, energy waste reduction, the
17 acquisition of the Covert Plant on June 1, 2023, continued operation of Ludington and Karn
18 Units 3 and 4, and the addition of Zonal Resource Credits (“ZRCs”) by June 1, 2025,
19 through a one-time solicitation approved as part of the Settlement Agreement.

20 **Q. What capacity resources were identified through the one-time solicitation?**

21 A. The IRP one-time solicitation resulted in the execution of 3 separate contracts totaling
22 400 MW of BESS projects. The Company’s January 12, 2024, filing of the Tibbits Energy
23 Storage, LLC Power Purchase Agreement (“PPA”), a 100-MW battery storage project

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1 which the MPSC approved in its April 11, 2024 Order. The term of the PPA is 20 years,
2 with deliveries expected to commence by May 31, 2025 with an expected PPA termination
3 date of May 31, 2045. The IRP one-time solicitation also resulted in the Company's
4 May 13, 2024 filing of the Century Oaks Energy Storage LLC PPA, a 200-MW battery
5 storage energy project. The Century Oaks Energy Storage LLC PPA also has a term of
6 20 years with deliveries expected to commence by May 31, 2026, and an expected PPA
7 termination date of May 31, 2046. Finally, the IRP one-time solicitation resulted in the
8 Company's September 27, 2024, filing of the Voyager Energy Storage LLC PPA, a
9 100-MW battery storage project which the MPSC approved in its November 21, 2024
10 Order. The Voyager Energy Storage LLC PPA also has a term of 20 years and, with
11 deliveries expected to commence by May 31, 2027, with an expected PPA termination date
12 of May 31, 2047. Each of these contracts were filed in MPSC Case No. U-21090.

13 **Q. What other actions has the Company taken to ensure it has sufficient capacity to**
14 **reliably serve its customers?**

15 A. In addition to the 400 MW of BESS PPAs, the Company has executed several agreements
16 with Midland Cogeneration Venture ("MCV") for short-term capacity measured in ZRCs.
17 On November 21, 2024, in Case No. U-21666, the Company received MPSC approval of
18 a contract for 100 ZRCs for the 2025, 2026, and 2027 planning years. On March 21, 2025,
19 in Case No. U-21827, the Company received MPSC approval of a contract for 175 ZRCs
20 for the 2025 and 2026 planning years. The contract was the result of a reverse capacity
21 auction that was conducted by an independent administrator on July 18, 2024.

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GENERATION ASSET STRATEGY

Q. Please describe the Company's asset strategy for its generating units.

A. The Company's generation asset strategy is focused on delivering safe, reliable, affordable, and clean energy and capacity for its customers. This strategy will be implemented within the construct of the Company's clean energy goals and its IRPs and renewable energy plans, as approved by the MPSC.

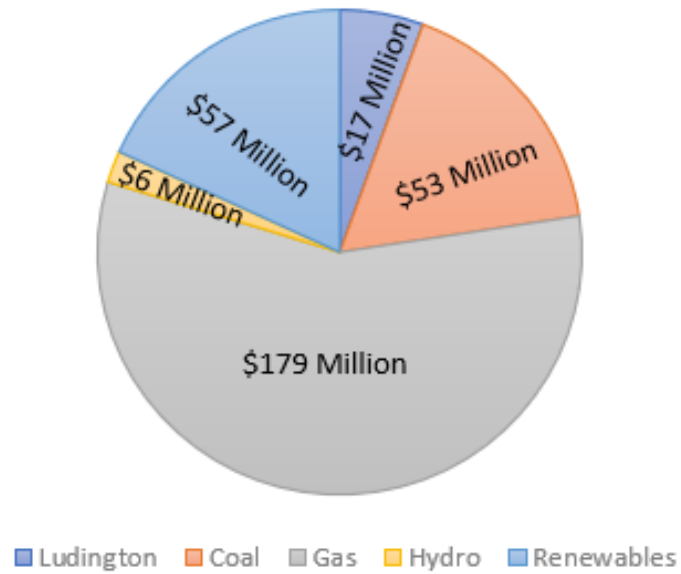
Q. How does the Company's generation asset strategy apply to the Company's various generating units?

A. Consistent with Consumers Energy's strategy, the Company's generating asset investments will focus on onboarding renewable energy resources, including BESSs as well as those generating assets that provide the most economic benefit to customers through their energy and capacity value in the respective MISO markets. In addition, the Company will also ensure it complies with all state and federal regulations.

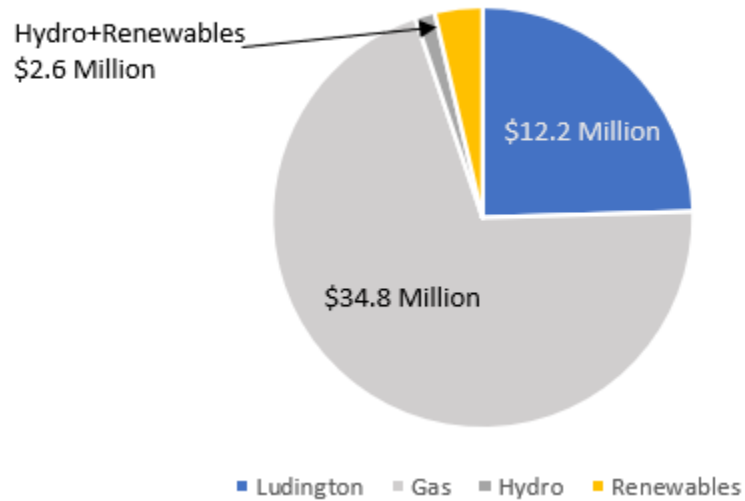
Consistent with the approval of the Company's Proposed Course of Action ("PCA") in its 2021 IRP and the Company's 2024 Amended Renewable Energy Plan, the Company will concentrate investment in new renewable energy resources and continue investment in the existing gas-fired units as this strategy will provide the greatest long-term customer benefit. During 2024, the Company's Covert, Zeeland and Jackson Plants produced over 70% of the net energy value and approximately 56% of the capacity value realized by the Company's electric generating fleet (excluding renewables). As such, the Company's investment focus and associated performance projections have been correspondingly set for these generating units. The figures below reflect the 2024 net energy and capacity value by asset type:

FIGURE 1

2024 Net Energy Value

**FIGURE 2**

Capacity



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1 **Q. How does the Company's generation asset strategy apply to the balance of the**
2 **Company's generating units?**

3 A. The Company's generation asset strategy with respect to the remaining generating units
4 will vary depending on each unit's energy value, capacity value, and consistency with the
5 Company's currently approved IRP expected retirement dates. The Company will continue
6 to maintain its generating units, including the River Hydro facilities, to ensure safe and
7 environmentally compliant operations. I will provide additional detail regarding the
8 Company's generation asset strategy for each of the generating units, or group of
9 generating units, in the portion of this direct testimony describing projected generating unit
10 availability.

11 **Q. Has the Company's existing generation asset strategy changed as a result of the 2023**
12 **Michigan energy legislation?**

13 A. Not materially. While Public Act ("PA") 235 of 2023 requires the Company to achieve a
14 50% renewable portfolio standard ("RPS") by 2030, the Company had already committed
15 to an aggressive transition in its generation asset portfolio mix through its 2018 and 2021
16 IRPs. Pursuant to PA 235 of 2023, the Company filed a Renewable Energy Plan
17 amendment on November 15, 2024, which reflected its plans to comply with the new
18 renewable energy laws.

19 With respect to the clean energy portion of the 2023 Michigan energy legislation,
20 the details for the Company's compliance with the clean energy portfolio targets contained
21 in that legislation will be reflected in the Company's proposed course of action in its next
22 IRP to be filed in 2026.

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**PERIODIC OUTAGE PLANS, AVAILABILITY, ROR PROJECTIONS,
AND NET ENERGY VALUE**

Q. Please describe Exhibit A-41 (RTB-1).

A. Exhibit A-41 (RTB-1) identifies the major outages (28 days or longer in duration) that are scheduled during the projected test year ending April 30, 2027 for the Company's fossil-fueled and Ludington Generating Units. The Company's generation asset strategy is a key input to the scheduling of planned outages, and outage duration directly informs the periodic factors ("PFs") reflected on Exhibit A-42 (RTB-2).

Q. Please describe Exhibit A-42 (RTB-2), Generating Unit Availability Projections.

A. Exhibit A-42 (RTB-2) details Generating Unit Availability Projections for Consumers Energy's peaking generation, and hydraulic power generation for the projected test year beginning May 1, 2026 and ending April 30, 2027. Column (a) identifies Consumers Energy's generating units or category of generating units. Column (b) identifies the five-year historical ROR of the generating unit or category of generating unit. Column (c) identifies the projected ROR of the unit or category of generating unit. Column (d) identifies the PF of the generating unit or category of generating unit. Column (e) identifies the projected availability of the generating unit or category of generating unit. Column (f) identifies the five-year historical Net Energy Value ("NEV") of the generating unit or category of generating unit.

Q. Please define ROR.

A. ROR is a measure of the percent of MWh unavailability due to forced or unplanned generating unit outages and forced or unplanned generating unit de-rates.

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1 **Q. What factors cause an increase or decrease in ROR?**

2 A. The frequency and/or duration of a forced or unplanned generating unit outage or
3 generating unit de-rate directly affects ROR. Reducing the frequency and/or duration of
4 forced or unplanned generating unit outages and generating unit de-rates decreases ROR.
5 Conversely, increasing the frequency and/or duration of forced or unplanned generating
6 unit outages and generating unit de-rates degrades ROR.

7 **Q. How are ROR projections for the Generating units developed?**

8 A. The ROR projections for the projected test year ending April 30, 2027 were developed
9 from the five-year (2020-2024) average. These five-year averages were then adjusted to
10 reflect current operating conditions and projected unit investment. The projected unit
11 investment is developed in accordance with the Company's generation asset strategy.
12 These five-year historical ROR average values are presented in Exhibit A-42 (RTB-2),
13 column (b).

14 **Q. Please define PF.**

15 A. PF is a measure of the percent of lost availability that results from planned outages, planned
16 outage extensions, planned de-rates, and planned de-rate extensions. Planned derates can
17 be taken for a variety of reasons, including the performance of necessary maintenance work
18 which does not require an outage to perform, or the management of emissions at gas
19 generation facilities to stay within environmental limits.

20 **Q. What strategy does the Company employ to minimize the impact of planned outages**
21 **on its customers?**

22 A. Consistent with the Company's generation asset strategy, the Company endeavors to
23 schedule planned generating unit outages during periods in which the margin between the

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1 generating unit production cost and the projected MISO energy market price is lowest.
2 This strategy results in creating greater total NEV as I will discuss in more detail later in
3 this direct testimony. In general, the projected MISO energy market pricing is lower in the
4 shoulder months of spring and fall due to historically lower demand. However, with the
5 introduction of seasonal capacity in the MISO market, the Company will also consider the
6 impact of outage scheduling on capacity accreditation for the four capacity seasons.
7 Company witness Metz describes seasonal capacity in more detail in her testimony.

8 **Q. Please define Projected Availability.**

9 A. Projected Availability is a measure of the percent of time that a generating unit or category
10 of generating units is projected to be available to generate electricity.

11 **Q. How is Projected Availability determined for each generating unit or category of**
12 **generating units?**

13 A. The Projected Availability for each generating unit or category of generating unit is
14 calculated as $(100\% - PF) * (100\% - ROR)$. Projected Availability is the key performance
15 metric for implementation of the Company's generation asset strategy for each generating
16 unit or category of generating unit.

17 **Q. How does the Company's generation asset strategy inform Projected Availability?**

18 A. As I previously discussed, the Company's generation asset strategy and associated
19 generation investment will focus on each unit's ability to provide economic value to
20 customers through the unit's ability to produce energy and capacity value in the respective
21 MISO markets. As such, those generating units or category of generating unit providing
22 the greatest amount of economic value to customers will be targeted to achieve the highest
23 projected availabilities.

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1 **Q. How can the Company impact Projected Availability for a generating unit?**

2 A. The Company can directly impact Projected Availability for a generating unit by
3 minimizing both PF and ROR for that unit. With respect to minimizing PF, the Company
4 can employ incremental resources during a planned outage to ensure that the critical path
5 for the outage is as short as possible. This strategy could include working 24-hours, seven
6 days a week, for the duration of the outage. Similarly, when a unit experiences an
7 unplanned outage, the Company can employ necessary resources to ensure the unit is
8 returned to available status as quickly as practical. In addition to minimizing unforced
9 outage length, the Company could invest in a generating unit to increase its reliability and,
10 as a result, decrease the generating unit's projected ROR.

11 **Q. Does the Company attempt to maximize availability for all its generating units or**
12 **category of generating units?**

13 A. No. Consistent with the Company's generation asset strategy, the Company focuses on
14 sustaining availability for those generating units which provide the greatest economic
15 benefit to customers through the energy value provided. The Company's generating units
16 get dispatched by MISO as part of the MISO energy market. Based upon the Company's
17 projected dispatch likelihood for each unit, the Company will rank the generating units
18 from highest economic value to least economic value, and manage the PF and the ROR,
19 and therefore the unit's Availability, to allow for the highest customer value. Or, stated
20 differently, the PF and ROR values may be allowed to be higher (lower unit Availability)
21 for the lower economic value units, and will be managed to lower values (higher unit
22 Availability) for higher economic value units.

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1 **Q. How does the Availability projection reflect the customer benefit?**

2 A. An improvement in Availability can translate to a customer benefit in several ways. The
3 immediate benefit is that the generating unit or the category of generating unit is available
4 for dispatch for a greater number of hours throughout the year, likely leading to increased
5 generation, and consequently higher NEV, on an annual basis. Additionally, higher
6 availability increases the ZRCs, increasing the capacity value of the unit.

7 **Q. How does the Company measure the customer benefit resulting from increased**
8 **generation?**

9 A. The Company utilizes NEV to quantify this customer benefit. At a high level, NEV of a
10 generating unit is the difference between the market value of energy and the cost of
11 producing and supplying that energy. NEV is the net customer benefit of a generator's
12 energy production expressed in dollars. These values are presented in Exhibit A-42
13 (RTB-2), column (f), which identifies five-year (2020-2024) actual NEV amounts.

14 **Q. What can the Company do to positively affect NEV?**

15 A. Typically, economic investments that improve the reliability and availability of the
16 generating unit or category of unit will result in increasing NEV. Economic investments
17 that result in a reduction in the cost to generate will also result in increasing NEV, all else
18 being equal. Positive NEV increases when a generating unit operates more frequently
19 during periods in which market pricing exceeds the cost of production for that unit.
20 Historically, market pricing has tended to be higher in the summer and winter, although
21 there is variability to market conditions. As discussed earlier in my testimony, this is the
22 reason that periodic outages are generally scheduled in the shoulder months of spring and

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1 fall. Market prices are typically lower during this time period, thereby reducing the PSCR
2 impact of each scheduled outage.

3 **Q. Does the cost of production vary for the Company's generating units?**

4 A. Yes. The basis for the Company's generation asset strategy is directly related to this
5 actuality. The Company's investment strategy is focused on those units with the lowest
6 variable production costs to maximize NEV for its customers. As the Company
7 strategically invests additional funds in a generating unit to increase its reliability, the
8 expectation is for the generating unit's reliability to be higher than otherwise possible
9 absent the investment. Higher reliability, in turn, increases the likelihood the unit is
10 available during periods when market prices exceed the production cost of the unit, thus
11 increasing the NEV of the unit.

12 **Q. Why is the measurement of NEV important to the Company and its customers?**

13 A. Positive NEV reflects a direct and immediate reduction to customer power supply costs
14 and consideration of NEV provides a basis for making operational and financial decisions
15 in order to maximize the customer value of the generating unit.

16 **Q. What is another measure the Company uses to evaluate economic projects for its
17 generating units?**

18 A. In addition to measuring NEV for a generating unit, the Company also considers the impact
19 a higher availability (specifically ROR) will have on the amount of capacity available from
20 a particular generating unit which receives a monetary credit in the MISO Resource
21 Adequacy Market. Table 2 below summarizes the current capacity value of the Company's
22 generating units based upon the summer season results in the 2024-2025 PRA for Zone 7.
23 Company witness Metz discusses the capacity value of the Company's generating units in

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the PRA in her testimony in this case. I will discuss the projected impact of the Company's generation asset strategy and associated capital expenditures and major maintenance on the projected availabilities, NEV, and capacity value for each of the generating units later in this direct testimony.

TABLE 2

RESOURCE	MICHIGAN LOCATION	MISO ISAC ¹ MW	MISO SUMMER SAC ² MW (ZRCs)	CAPACITY VALUE ZONE 7 (SETTLEMENT) ³	CAPACITY VALUE ZONE 7 (75% CONE) ⁴
OIL OR GAS FIRED					
Covert	Covert, MI	1089.5	952.9	\$ 10,434,255	\$ 70,178,191
DE Karn 3	Essexville, MI	602.1	367	\$ 4,018,650	\$ 27,028,435
DE Karn 4	Essexville, MI	586.8	542.3	\$ 5,938,185	\$ 39,938,748
Zeeland CC	Zeeland, MI	533.8	501.5	\$ 5,491,425	\$ 36,933,952
Zeeland 1A	Zeeland, MI	157.6	153.3	\$ 1,678,635	\$ 11,290,079
Zeeland 1B	Zeeland, MI	156.7	153	\$ 1,675,350	\$ 11,267,985
Jackson	Jackson, MI	531	508.6	\$ 5,569,170	\$ 37,456,845
HYDROELECTRIC					
Alcona	Alcona County, MI	2.7	2.7	\$ 29,565	\$ 198,847
Allegan	Allegan County, MI	1.2	1.2	\$ 13,140	\$ 88,376
Cooke	Iosco County, MI	7.2	6.8	\$ 74,460	\$ 500,799
Croton	Newaygo County, MI	2.1	2.1	\$ 22,995	\$ 154,659
Five Channels	Iosco County, MI	6.2	5.8	\$ 18,615	\$ 427,152
Footte	Iosco County, MI	2.7	2.8	\$ 30,660	\$ 206,211
Hardy	Newaygo County, MI	33.3	32.4	\$ 354,780	\$ 2,386,162
Hodenpyl	Wexford County, MI	4.1	4.1	\$ 44,895	\$ 301,953
Loud	Iosco County, MI	5	4.8	\$ 52,560	\$ 353,505
Mio	Oscoda County, MI	1.3	1.3	\$ 14,235	\$ 95,741
Rogers	Mecosta County, MI	2	2.1	\$ 22,995	\$ 154,659
Tippy	Manistee County, MI	5.8	5.8	\$ 63,510	\$ 427,152
Webber	Ionia County, MI	1	1	\$ 10,950	\$ 73,647
RENEWABLES					
Lake Winds	Mason County, MI	100.8	17.9	\$ 196,005	\$ 1,318,281
Cross Winds (Phase I, II, III)	Tuscola County, MI	230.6	52.9	\$ 579,255	\$ 3,895,924
Crescent Wind	Jonesville, MI	166	24.4	\$ 267,180	\$ 1,796,986
Gratiot Farms Wind	Alma, MI	149.7	36.3	\$ 397,485	\$ 2,673,385
Heartland Farms Wind Park	Ithaca, MI	200	31.5	\$ 344,925	\$ 2,319,879
Solar Gardens- GVSU	Grand Rapids, MI	3	1.7	\$ 18,615	\$ 125,200
Solar Gardens- WMU	Kalamazoo, MI	1	0.6	\$ 6,570	\$ 44,188
Cadillac Solar Garden	Cadillac, MI	0.5	0.2	\$ 2,190	\$ 14,729
Circuit West	Grand Rapids, MI	0.5	0.2	\$ 2,190	\$ 14,729
ENERGY STORAGE					
Ludington Units 1-6	Ludington, MI	1138.0 (owned share)	1110	\$ 12,154,500	\$ 81,748,128
¹ ISAC = Intermediate seasonal accredited capacity ² SAC = Seasonal accredited capacity and is converted from ISAC based upon offered availability during RA and non-RA hours ³ 2024-2025 Summer PRA Settlement price of \$30/MW-day for Zone 7. ⁴ 2024-2025 PRA 75% CONE price of \$269.03/MW-day for Zone 7.					

Q. Please provide an overview of the generation asset strategy for Karn Units 3 and 4.

A. The strategic plan for Karn Units 3 and 4 is predicated on their planned retirement on May 31, 2031 as reflected in the Company's 2021 IRP Settlement Agreement. The overall remaining life objective for Karn Units 3 and 4 is to maintain capacity value from the customer's perspective. The capital expenditures and major maintenance expenses in the

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1 plan are targeted to provide safe and regulatory compliant units, as well as maintain
2 capacity accreditation. Critical reliability investments required to keep the units available
3 will be included in the plan.

4 **Q. How will the Company's generation asset strategy for Karn Units 3 and 4 impact their**
5 **projected performance?**

6 A. It is anticipated that unit performance for Karn Units 3 and 4 will slightly degrade from
7 current performance. Based upon the Karn Units 3 and 4 capital and major maintenance
8 projects that I will discuss later in this direct testimony, the Company's generation asset
9 strategy is expected to result in an ROR of 18.00% at Karn Unit 3 and 18.00% at Karn
10 Unit 4 in the test year, as shown on Exhibit A-42 (RTB-2), lines 1 and 2, column (c).
11 During the five-year historical period from 2020 through 2024, Karn Unit 3 had an ROR
12 of 38.70% and Karn Unit 4 had an ROR of 24.76%, as shown on Exhibit A-42 (RTB-2),
13 lines 1 and 2, column (b).

14 **Q. How is this strategy reflected in the Projected Availability for Karn Units 3 and 4 in**
15 **the test year?**

16 A. The projected availabilities for Karn Units 3 and 4 in the test year are 69.13% and 72.97%,
17 respectively, as shown on Exhibit A-42 (RTB-2), lines 1 and 2, column (e). The
18 availability for Karn Unit 3 reflects a projected ROR of 18.00% and a PF of 15.69%, as
19 shown on Exhibit A-42 (RTB-2), line 1, columns (c) and (d). The planned outages for the
20 test year are scheduled to begin on October 12, 2026 and last for 30 days, and March 22,
21 2027 and last for 29 days, as reflected on Exhibit A-41 (RTB-1), lines 7 and 9. The
22 availability for Karn Unit 4 reflects a projected ROR of 18.00% and a PF of 11.01%, as
23 shown on Exhibit A-42 (RTB-2), line 2, columns (c) and (d). The planned outages for the

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test year are scheduled to begin on October 12, 2026 and last for 30 days, and March 22, 2027 and last for 29 days, as reflected on Exhibit A-41 (RTB-1), lines 8 and 10.

Q. How does the Projected Availability for Karn Units 3 and 4 translate into customer value?

A. As reflected on Exhibit A-42 (RTB-2), lines 1 and 2, column (f), during the five-year historical period from 2020 through 2024, Karn Unit 3 had a NEV of -\$8.1 million and Karn Unit 4 had a NEV of -\$10.4 million. The 2024 NEV for each of these units was -\$1.7 million and -\$0.4 million for Karn Units 3 and 4, respectively.

Q. Please explain why the NEVs for Karn Units 3 and 4 are negative.

A. The NEVs for Karn Units 3 and 4 are negative due to required operation in support of capacity demonstration testing, unit performance validation, and operator training. During this operation, the units are operated as Must-Run resources in the MISO Energy Market and as such, they are price takers. In order to minimize the impact of the required operation of the units, the Company performs those activities during periods in which operation is most economic. However, despite the fact that the NEVs are slightly negative, the units provide a significant amount of capacity value, which far outweighs the negative NEV values. In addition, the Company's ability to have these units dispatched during tight generation days provides reliability benefits for the Company's customers and the MISO energy market.

Q. Please quantify the capacity value for Karn Units 3 and 4.

A. As reflected in Table 2, the capacity value based upon the settlement price for Zone 7 in the 2024-2025 PRA is \$4.0 million for Karn Unit 3 and \$5.9 million for Karn Unit 4. The

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1 hypothetical capacity value based upon 75% of CONE for Zone 7 in the 2024-2025 PRA
2 is \$27.0 million for Karn Unit 3 and \$39.9 million for Karn Unit 4.

3 **Q. Please provide an overview of the generation asset strategy for the Zeeland Plant.**

4 A. The strategic plan for the Zeeland Plant is predicated on plant operation through Planning
5 Year 2040. The overall long-term objective for the Zeeland Plant is to increase economic
6 dispatch and capacity from the customer's perspective. The units provide significant value
7 to customers in both the energy and resource adequacy markets and the turbine projects
8 discussed later in this direct testimony aim to increase customer value. The capital
9 expenditures and major maintenance expenses in the plan are targeted to provide a safe,
10 regulatory compliant, and reliable unit. Critical reliability investments required to keep the
11 units available will be included in the plan. Projects that are targeted to improve dispatch
12 and reliability, such as the turbine projects, are included in the plan as they provide value
13 to customers.

14 **Q. How will the Company's generation asset strategy for the Zeeland Plant impact its**
15 **projected performance?**

16 A. It is anticipated that site performance will remain relatively consistent with current
17 performance. Based upon the Zeeland Plant capital and major maintenance projects that
18 I will discuss later in this testimony, the Company's generation asset strategy is expected
19 to result in an ROR of 4.0% at the Zeeland Plant in the test year, as shown on Exhibit A-42
20 (RTB-2), lines 10 through 12, column (c). During the five-year historical period from 2020
21 through 2024, the Zeeland Plant had ROR values at or below 7.48% for all units, as shown
22 on Exhibit A-42 (RTB-2), lines 10 through 12, column (b).

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1 **Q. How is this strategy reflected in the Projected Availability for the Zeeland Plant in**
2 **the test year?**

3 A. The Projected Availability for the combined cycle generating units (Units 1 and 2) at the
4 Zeeland Plant in the test year is 87.80%, as shown on Exhibit A-42 (RTB-2), line 10,
5 column (e). The Zeeland Combined Cycle (Units 3, 4, and 5) Generating Unit availability
6 is based upon a projected ROR of 4.0% and a PF of 8.54%, as shown on Exhibit A-42
7 (RTB-2), line 10, columns (c) and (d). The Projected Availabilities for each of the simple
8 cycle generating units at the Zeeland site in the projected test year are 89.98%, as shown
9 on Exhibit A-42 (RTB-2), lines 11 and 12, column (e). Each of the Zeeland simple cycle
10 generating unit Projected Availabilities are based upon projected RORs of 4.0% and PFs
11 of 6.27%, as shown on Exhibit A-42 (RTB-2), lines 11 and 12, columns (c) and (d). There
12 are no outages greater than 28 days scheduled for the Zeeland combined cycle units
13 (Units 3, 4, and 5) in the projected test year ending April 30, 2027, however there are
14 several shorter duration outages of 14 days, each scheduled in May and October, 2026.
15 There are no outages greater than 28 days scheduled for the Zeeland simple cycle units
16 (Units 1 and 2) in the projected test year ending April 30, 2027, however there is a 13-day
17 outage on each unit in the spring of 2026, a 3-day outage on each unit in September 2026,
18 and a 14-day outage on each unit in the spring of 2027. These outages are scheduled during
19 periods in which energy prices are projected to be lower, thereby reducing the impact of
20 the outages on customers. In addition, the outages are scheduled to maximize future
21 capacity attribution for the units given the MISO seasonal resource adequacy construct.

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1 **Q. How does the Zeeland Plant Projected Availability translate into customer value?**

2 A. As reflected on Exhibit A-42 (RTB-2), lines 10 through 12, column (f), during the five-year
3 historical period from 2020 through 2024, the Zeeland Plant provided a total NEV of
4 \$220.5 million. The 2024 NEV for Zeeland was \$49.4 million.

5 **Q. Please quantify the capacity value for the Zeeland Plant.**

6 A. As reflected in Table 2, the Zeeland Plant capacity value based upon the settlement price
7 for Zone 7 in the 2024-2025 PRA is \$8.8 million and the Zeeland Plant hypothetical
8 capacity value based upon 75% of CONE for Zone 7 in the 2024-2025 PRA is
9 \$59.5 million.

10 **Q. Please provide an overview of the generation asset strategy for the Jackson Plant.**

11 A. The strategic plan for the Jackson Plant is predicated on plant operation through Planning
12 Year 2040. The overall long-term objective for the Jackson Plant is to maintain economic
13 dispatch and capacity from the customer's perspective. The units provide significant value
14 to customers in both the energy and resource adequacy markets. The capital expenditures
15 and major maintenance expenses in the plan are targeted to provide a safe, regulatory
16 compliant, and reliable unit. Critical reliability investments required to keep the units
17 available will be included in the plan. Projects that are targeted to improve reliability will
18 be included in the plan if they provide value to customers.

19 **Q. How will the Company's generation asset strategy for the Jackson Plant impact its**
20 **projected performance?**

21 A. It is anticipated that site performance will remain relatively consistent with current
22 performance. Based upon the Jackson Plant capital and major maintenance projects that
23 I will discuss later in this direct testimony, the Company's generation asset strategy is

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1 expected to result in an ROR of 4.50% at the Jackson Plant in the test year, as shown on
2 Exhibit A-42 (RTB-2), line 13, column (c). During the five-year historical period from
3 2020 through 2024, the Jackson Plant had an actual ROR of 8.22%, as shown on Exhibit
4 A-42 (RTB-2), line 13, column (b).

5 **Q. How is this strategy reflected in the Projected Availability for the Jackson Plant in**
6 **the test year?**

7 A. The Projected Availability for all of the generating units at the Jackson site in the test year
8 is 92.09%, as shown on Exhibit A-42 (RTB-2), line 13, column (e). The Projected
9 Availability for the Jackson site reflects a projected ROR of 4.50% and a PF of 3.57%, as
10 shown on Exhibit A-42 (RTB-2), line 13, columns (c) and (d). There are no major planned
11 outages in excess of 28 days for the Jackson units in the test year, however a short 12.5-day
12 outage is scheduled April 2027. In addition, several derates are scheduled to perform
13 inspections and maintenance on various generating units in September and October 2026
14 and March of 2027.

15 **Q. How does the Jackson Plant Projected Availability translate into customer value?**

16 A. As reflected on Exhibit A-42 (RTB-2), line 13, column (f), during the five-year historical
17 period from 2020 through 2024, the Jackson units provided a total NEV of \$158.4 million.
18 The 2024 NEV for the Jackson Plant was \$24.1 million.

19 **Q. Please quantify the capacity value for the Jackson Plant.**

20 A. As reflected in Table 2, the Jackson Plant capacity value based upon the settlement price
21 for Zone 7 in the 2024-2025 PRA is \$5.6 million and the Jackson Plant hypothetical
22 capacity value based upon 75% of CONE for Zone 7 in the 2024-2025 PRA is
23 \$37.5 million.

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1 **Q. How will the Company's generation asset strategy for the Covert Plant impact its**
2 **projected performance?**

3 A. It is anticipated that site performance will remain relatively consistent with past
4 performance under different ownership. Based upon the Covert Plant capital and major
5 maintenance projects that I will discuss later in this direct testimony, the Company's
6 generation asset strategy is expected to result in an ROR of 7.00% for all three units at the
7 Covert Plant in the test year, as shown on Exhibit A-42 (RTB 2), lines 14 through 16,
8 column (c).

9 **Q. How is this strategy reflected in the Projected Availability for the Covert Plant in the**
10 **test year?**

11 A. The Projected Availability for each of the combined cycle generating units at the Covert
12 Plant in the test year ranges from 74.12% to 87.54%, as shown on Exhibit A-42 (RTB-2),
13 lines 14 through 16, column (e). The Covert Unit 1 unit availability of 74.12% is based
14 upon projected ROR of 7.00% and a PF of 20.30%, as shown on Exhibit A-42 (RTB-2),
15 line 14, columns (c) and (d); the Covert Unit 2 unit availability of 87.54% is based upon
16 projected ROR of 7.00% and a PF of 5.87%, as shown on Exhibit A-42 (RTB-2), line 15,
17 columns (c) and (d); and the Covert Unit 3 unit availability of 84.80% is based upon
18 projected ROR of 7.00% and a PF of 8.81%, as shown on Exhibit A-42 (RTB-2), line 16,
19 columns (c) and (d). The Company will conduct major inspections at all three of the Covert
20 Units during the bridge period/test year. The planned outage for the test year for Covert
21 Unit 1 is scheduled to begin on September 1, 2026 and last for 59 days as reflected on
22 Exhibit A-41 (RTB-1), line 2. The planned outage for the bridge period for Covert Unit 2
23 began on March 1, 2025 and ended on May 25, 2025. The planned outage for the bridge

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1 period/test year for Covert Unit 3 is scheduled to begin on March 15, 2026 and last for
2 59 days, as reflected on Exhibit A-41 (RTB-1), line 1. These outages are scheduled for
3 periods in which energy prices are projected to be lower, thereby reducing the impact of
4 the outages on customers. In addition, the outages are scheduled to maximize future
5 capacity attribution for the units given the MISO seasonal resource adequacy construct.

6 **Q. How does the Covert Plant Projected Availability translate into customer value?**

7 A. As reflected on Exhibit A-42 (RTB-2), lines 14 through 16, column (f), during the
8 19-month historical period beginning June 1, 2023 through December 31, 2024, the Covert
9 units provided a total NEV of \$49.4 million. The 2024 NEV for the Covert Plant was
10 \$24.1 million.

11 **Q. Please quantify the capacity value for the Covert Plant.**

12 A. As reflected in Table 2, the Covert Plant capacity value based upon the settlement price for
13 Zone 7 in the 2024-2025 PRA is \$10.4 million and the Covert Plant hypothetical capacity
14 value based upon 75% of CONE for Zone 7 in the 2024-2025 PRA is \$70.2 million.

15 **Q. Please provide an overview of the Company's generation asset strategy for the River
16 Hydro units.**

17 A. The strategic plan for the Company's River Hydro units is currently predicated on
18 operating the units consistent with the Company's Federal Energy Regulatory Commission
19 ("FERC") project licenses. Continued operation of these facilities is assumed in the
20 Company's current IRP that was approved by the MPSC in Case No. U-21090. These units
21 deliver customer value by providing renewable energy and capacity. River Hydro facilities
22 also provide value to their surrounding local communities and to the state of Michigan in
23 the form of recreational opportunities, natural preservation, and environmental benefits.

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1 The overall long-term objective for the River Hydro units is to maintain safe and reliable
2 River Hydro sites for our customers, to ensure compliance with FERC obligations and
3 other regulatory requirements, and to continue providing valuable benefits to local
4 residents, surrounding communities, and the state of Michigan.

5 **Q. Is it possible the River Hydro facilities could be retired early or not be relicensed?**

6 A. Yes. The Company is always evaluating its long-term generation strategy, including for
7 the River Hydro units. As a result of a Settlement Agreement in the Company's most
8 recent general electric depreciation case, Case No. U-20849 and a filing extension
9 approved in Case No. U-21783, Consumers Energy will present retirement and
10 decommissioning analysis for its River Hydro facilities to the Commission by the end of
11 2025. The Company will evaluate each facility and determine the best path forward from
12 the perspective of Consumers Energy, its customers, and the State of Michigan. Although
13 this analysis has not been completed, it is clear that compliance with FERC requirements
14 will require continued investment in safety and reliability upgrades to operate these River
15 Hydro facilities well into the future.

16 **Q. Has the Company presented any River Hydro capital investments in this electric rate**
17 **case?**

18 A. No. In the March 21, 2025 Final Order in the Company's 2024 Electric Rate Case No.
19 U-21585, the Commission found that the "company may use deferred regulatory
20 accounting of the revenue requirement on actual capitalized investments incurred subject
21 to review in the company's next electric rate case."² The Commission went on to state that
22 this accounting authority does not relieve the Company of meeting the evidentiary burden

² Case No. U-21585, March 21, 2025 Final Order, p 157.

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1 for its investments. As such, the Company has not presented any River Hydro projects for
2 the bridge period and test year and intends to seek recovery in a future regulatory
3 proceeding.

4 **Q. Has the Company presented actual River Hydro investments for the historical test**
5 **year?**

6 A. No. As discussed in more detail in the direct testimony of Company witness Myers, the
7 Company is requesting the continuation of the deferral through the test year of this rate
8 case and, as such, has not presented its actual 2024 River Hydro capital expenditures. This
9 is due to the continuing uncertain future of the River Hydros. The Company's
10 potential future scenarios for the River Hydros include divestiture, decommissioning, and
11 relicensing and continuing operation.

12 **Q. What is the status of the Request for Proposals ("RFP") for River Hydro divestiture?**

13 A. The Company launched an RFP to identify potential buyers for its 13 River Hydro facilities
14 on February 15, 2024. As part of the first phase of the RFP, which involved bidder
15 screening based on, among other things, qualifications and indicative pricing, the Company
16 received responses to the RFP on March 15, 2024. The Company evaluated the bids and
17 moved to the second phase of the RFP in April of 2024.

18 **Q. Please discuss Phase 2 of the RFP for River Hydro divestiture.**

19 A. Phase 2 involved initially engaging with seven selected entities in due diligence,
20 negotiations, and potential sale agreement(s). Due diligence was completed during the
21 summer of 2024, at which time negotiations began with selected bidders. The Company's
22 negotiations are continuing with the expectation of reaching a contract mid-year 2025.

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1 **Q. What are the next steps following the execution of a contract for divestiture?**

2 A. To the extent that the Company can reach an agreement on their divestiture, the Company
3 would file an application with the MPSC and FERC for approval of the sale and related
4 agreements.

5 **Q. How will the Company move forward if divestiture fails or is rejected by the**
6 **Commission?**

7 A. To the extent that the Company is unable to reach an agreement for sale of the River Hydros
8 or a potential sale is rejected, the Company would revisit the decision to relicense or
9 decommission the River Hydros, with the intention of making a decision as soon as
10 possible following a decision to not divest.

11 **Q. Is the Company requesting the recovery of O&M expense for the River Hydros in this**
12 **proceeding?**

13 A. Yes. The Company has reflected River Hydro O&M expense in my Exhibit A-43 (RTB-4)
14 for the historic year, the 16-month bridge period, and the test year. The Company will
15 discuss its proposal for future O&M expense later in this direct testimony.

16 **Q. How will the Company's generation asset strategy for the River Hydro units impact**
17 **their projected performance?**

18 A. It is anticipated that future River Hydro unit performance will remain relatively consistent
19 with current River Hydro unit performance, provided that necessary investments are made
20 to ensure safe and reliable operation. In other words, as assumed in Consumers Energy's
21 current IRP, the Company currently expects its River Hydro facilities can continue to
22 deliver reliable clean energy to customers while maintaining their long record of
23 operational, safety, and environmental performance. Based upon the River Hydro unit

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1 major maintenance projects that I will discuss later in this direct testimony, the Company's
2 generation asset strategy is expected to result in an ROR of 5.60% for the River Hydro
3 units in the projected test year ending April 30, 2027, as shown on Exhibit A-42 (RTB-2),
4 line 9, column (c). During the five-year historical period from 2020 through 2024, the
5 River Hydro units had an ROR of 9.48% for all units, as shown on Exhibit A-42 (RTB-2),
6 line 9, column (b).

7 **Q. How is this strategy reflected in the projected availability for the River Hydro units**
8 **in the projected test year?**

9 A. The projected availability for all of the River Hydro units in the projected test year is
10 89.38%, as shown on Exhibit A-42 (RTB-2), line 9, column (e). The Projected Availability
11 for the River Hydro units reflects a projected ROR of 5.60% and a PF of 5.32%, as shown
12 on Exhibit A-42 (RTB-2), line 9, columns (c) and (d). These projections reflect (i) a
13 109-day planned outage at Cooke Unit 1 for replacement of the downstream right retaining
14 wall, (ii) a 270-day planned outage at Five Channels Unit 2 for wicket gate replacement,
15 (iii) a 270-day planned outage at Croton Unit 3 for unit overhaul, (iv) a 249-day planned
16 outage at Webber Unit 1 for generator rewind and unit overhaul, (v) a 270-day planned
17 outage at Loud Unit 1 for wicket gate replacement, (vi) a 82-day planned outage at Tippy
18 Units 1-3 for an electric safety upgrade, and (vii) a 270-day planned outage at Croton Unit
19 4 for periodic inspection and thrust bearing inspection.

20 **Q. How does the River Hydro unit Projected Availability translate into customer value?**

21 A. As reflected on Exhibit A-42 (RTB-2), line 9, column (f), during the five-year historical
22 period from 2020 through 2024, the River Hydro units which are registered with MISO

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(Alcona, Croton, Hardy, Hodenpyl, and Tippy) provided a total NEV of \$44.9 million. The 2024 NEV for the River Hydro units registered with MISO was \$6.6 million.

Q. Please quantify the capacity value for the River Hydro units?

A. As reflected in Table 2, the capacity value of the River Hydro units based upon the settlement price for MISO Zone 7 in the 2024-2025 MISO PRA is \$0.8 million and the River Hydro unit hypothetical capacity value based upon 75% of Cost of New Entry for Zone 7 in the 2024-2025 PRA is \$5.4 million.

Q. Please provide an overview of the generation asset strategy for Ludington.

A. The strategic plan for Ludington is predicated on retiring the units by July 30, 2069. The Ludington units recently underwent a major overhaul that was intended to provide increased capacity and generation, increased efficiency, reduced maintenance, and an extended service life which supported the 50-year FERC license extension granted in 2019. Ludington is a FERC-regulated hydroelectric facility for which dam safety investments are identified and initiated as a result of regulatory compliance and adherence to FERC processes, including the FERC Part 12 process.

Q. How will the Company's generation asset strategy for Ludington impact its projected performance?

A. Based upon the Ludington capital and major maintenance projects that I will discuss later in this direct testimony, the Company's generation asset strategy is expected to result in an ROR of 3.50% for the Ludington units in the test year, as shown on Exhibit A-42 (RTB-2), lines 3 through 8, column (c). During the five-year historical period from 2020 through 2024, the Ludington units had average ROR values ranging from 4.94% to 7.75%, as shown on Exhibit A-42 (RTB-2), lines 3 through 8, column (b).

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1 **Q. How do the Ludington Units factor into the Company's future renewable energy**
2 **strategy as outlined in the IRP?**

3 A. Given the intermittent nature of solar and wind generation and the Company's plans to
4 move to a zero net carbon future, Ludington is becoming a more critical component of the
5 Company's generation portfolio since it can deliver a significant amount of energy in a
6 short time period; providing energy supply from the reservoir during periods when the
7 wind doesn't blow and/or the sun doesn't shine. Additionally, when there is an
8 over-abundance of wind and/or solar generation, Ludington can utilize the excess energy
9 to fill the reservoir. Ludington's large energy storage capability greatly enables the
10 transition to renewable energy. However, defective and non-conforming work performed
11 by Toshiba during recent overhaul efforts must be resolved to ensure Ludington can fully
12 provide these intended benefits over its remaining life.

13 **Q. How is this strategy reflected in the Projected Availability for Ludington in the test**
14 **year?**

15 A. The Projected Availabilities for all of the Ludington units in the projected test year ranges
16 from 0.00% to 84.01%, as shown on Exhibit A-42 (RTB-2), lines 3 through 8, column (e).
17 The Projected Availabilities for the Ludington generating units reflect a projected ROR of
18 3.50% and PFs ranging from 12.94% to 100.00%, as shown on Exhibit A-42 (RTB-2),
19 lines 3 through 8, columns (c) and (d). There are four major outages planned for the
20 Ludington units in the test year: a 274-day outage on Ludington Unit 3 beginning on
21 September 2, 2026 as presented on Exhibit A-41 (RTB-1), line 3; a 49-day outage on
22 Ludington Unit 6 beginning on September 8, 2026 as presented on Exhibit A-41 (RTB-1),
23 line 4; a 42-day outage on Ludington Unit 5 beginning on September 10, 2026 as presented

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1 on Exhibit A-41 (RTB-1), line 5; and a 683-day outage on Ludington Unit 4 beginning on
2 October 19, 2026 as presented on Exhibit A-41 (RTB-1), line 6. In addition, shorter
3 outages on all six Ludington units are scheduled throughout the test year, primarily in the
4 spring and fall. These outages will be used, in part, to perform cooling water strainer
5 cleaning, install and remove the barrier net, and perform other necessary inspections. To
6 the extent possible, the outages are scheduled during periods in which the likelihood of
7 Ludington unit dispatch is lower, thereby reducing the impact of the outages on customers.

8 **Q. Please provide an overview of the generation asset strategy for the Renewable Energy**
9 **Assets.**

10 A. The Company's strategic plan for Renewable Energy Assets, both wind and solar,
11 continues to be primarily driven by the Company's MPSC-approved 2021 IRP Settlement
12 Agreement. Consistent with the IRP, all previously identified wind assets were in service
13 throughout 2024. For solar, the Company plans to continue to add incremental solar
14 resources in accordance with its Clean Energy Plan and Renewable Energy Plans. These
15 solar resources are being added pursuant to the Company's annual IRP solicitations, as
16 discussed in more detail later in this direct testimony. In addition, the Company anticipates
17 that it will also add wind and solar assets for the foreseeable future in support of the
18 Company's Voluntary Green Pricing Program, and their costs will be reconciled through
19 the Company's Renewable Energy Plan.

20 **Q. Is the Company requesting recovery of renewable energy assets in this proceeding?**

21 A. No. The Commission approved the movement of cost recovery for renewable energy
22 resources to the Company's Renewable Energy Plan in its March 21, 2025 Order in Case

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1 No. U-21585. As such, all costs for renewable energy assets will be presented and
2 reconciled in renewable energy plans.

3 **Q. How will the enactment of PA 235 of 2023 impact the Company's future renewable**
4 **energy portfolio?**

5 A. As previously discussed in this direct testimony, the Company filed a Renewable Energy
6 Plan Amendment on November 15, 2024. PA 235 of 2023 has established both renewable
7 and clean energy targets for the future beginning with a renewable energy compliance
8 target of 50% in 2030. The newly passed law became effective on February 27, 2024 and
9 provides for the utilization of renewable energy assets from anywhere within the MISO
10 footprint.

11 The Company's Renewable Energy Plan Amendment proposes the addition of
12 2,800 MW of renewable energy wind resources and an additional 1,000 MW of renewable
13 energy solar resources, over and above the Company's glidepath established in its 2021
14 IRP settlement.

15 **Q. How do the Company's renewable assets translate into customer value?**

16 A. Similar to the Company's River Hydro units, the production cost of the Company's
17 renewable energy assets is zero. As such, all energy sold into the MISO energy market has
18 value provided that the MISO locational marginal prices are positive. Additionally,
19 renewable assets provide the Company's customers with renewable energy credits. As
20 reflected on Exhibit A-42 (RTB-2), lines 17 through 18, column (f), during the five-year
21 historical period from 2020 through 2024, the Cross Winds Energy Park and the Lake
22 Winds Energy Park provided a total NEV of \$166.7 million. As reflected on Exhibit A-42
23 (RTB-2), lines 19 through 20, column (f), during the three-year historical period from 2022

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1 through 2024, Gratiot Farms Wind and Crescent Wind provided total NEV of
2 \$68.5 million. Heartland Farms Wind Park began commercial operation on December 29,
3 2023, and as reflected on Exhibit A-42 (RTB-2), line 21, column (f), generated \$0.4 million
4 in NEV in 2023. The Company began to measure the NEV for its solar assets in 2020 and
5 the 2020 through 2024 NEV for its Solar Garden Assets totaled \$1.1 million.

6 **Q. Please quantify the capacity value for renewable energy assets.**

7 A. As reflected in Table 2, the renewable asset capacity value based upon the settlement price
8 for Zone 7 in the 2024-2025 PRA is \$0.4 million and the renewable asset hypothetical
9 capacity value based upon 75% of CONE for Zone 7 in the 2024-2025 PRA is \$2.5 million.

10 **Q. Why have you included a hypothetical capacity value for each of the generating units**
11 **or category of generating units?**

12 A. I have included these hypothetical values to reflect the capacity values that the Company
13 uses in its capacity planning process. Company witness Metz provides additional
14 information regarding the capacity value of the Company's generation assets in MISO's
15 PRA as well as the projected capacity margin in future years for Zone 7.

16 **Q. How will the Company determine the reasonableness and prudence of additional**
17 **investments in the electric generating fleet?**

18 A. Additional investment in the remaining units over and above those necessary to maintain
19 safety and regulatory compliance would require some level of economic benefit for
20 customers, otherwise the investment does not make sense. The generating unit periodic
21 outage plans, projected RORs and, ultimately, projected availability for each generating
22 unit or category of generating units reflects the Company's generation asset strategy.

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SECTION II

ENVIRONMENTAL REGULATIONS

OVERVIEW

Q. Can you please list the environmental regulations with which Consumers Energy is required to comply and that are relevant to expenditures for which the Company is seeking recovery in this case?

A. Yes. The Company's fossil-fueled Electric Generating Units ("EGUs") are subject to numerous complex and overlapping air, water, and waste regulations.

CURRENT (ON-GOING) ENVIRONMENTAL COMPLIANCE

Environmental Regulations – Air Quality

Q. Describe Consumers Energy's Existing Air Quality Compliance Strategy ("AQCS").

A. Over the past decade, Consumers Energy has had expenditures to comply with a variety of air quality-related regulations, including the Cross State Air Pollution Rule, the Mercury and Air Toxics Standards, and the Michigan Mercury Rule, among others. The background and purpose of each such rule has been discussed in the testimony of prior rate cases, including Case No. U-17735. To comply with these regulations, Consumers Energy created the AQCS. Cost recovery reflecting the Company's AQCS was approved in the November 19, 2015 Order in the Company's 2014 Electric Rate Case (Case No. U-17735). This AQCS has prudently ensured compliance with applicable state and federal air-quality related regulations. The Company's actions and investments to achieve such compliance have been performed in a manner which has minimized, to the extent reasonably possible, the associated costs for customers. The investments made to ensure environmental compliance have allowed the continued operation of coal generation while the Company transitions to carbon-free generation sources like solar.

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1 **Q. Are there any updates to the air quality-related regulations for which the Company's**
2 **existing AQCS complies?**

3 A. Yes. In April 2022 the Environmental Protection Agency ("EPA") proposed the "Federal
4 Implementation Plan Addressing Regional Ozone Transport for the 2015 Ozone National
5 Ambient Air Quality Standard" under the "good neighbor" provision of the Clean Air
6 Act. The EPA's rule was finalized, effective March 15, 2023 but this revision was stayed
7 in 2024 and the prior 2017 Cross-State Air Pollution Rule ("CSAPR") remains in effect.
8 On March 12, 2025, U.S. EPA Administrator Lee Zeldin announced the agency will
9 undertake action to "end the Good Neighbor Plan." It is most likely that CSAPR will remain
10 in effect. The Company will continue to monitor the rule and evaluate various options for
11 compliance as needed.

12 **Q. What are the capital investments and/or O&M expenses the Company is seeking to**
13 **recover in this case that are specifically related to air quality control?**

14 A. Any O&M required for the operation of the air quality control systems that the Company
15 is seeking recovery can be found in Exhibit A-43 (RTB-4).

16 **Q. Are you seeking recovery of any expenses related to the regulation of greenhouse**
17 **gases from EGUs?**

18 A. No, not at this time. On June 19, 2019, the EPA finalized three rulemakings: (i) repeal of
19 the Clean Power Plan; (ii) issuance of the final Affordable Clean Energy ("ACE") Rule
20 and; (iii) issuance of new Clean Air Act ("CAA") section 111(d) regulations. In May 2024,
21 EPA issued a Final GHG standards for new and existing fossil fuel-fired EGUs under
22 Section 111 of the CAA and the ACE Rule was repealed. These new requirements do not
23 impact the Company's fleet due to the planned retirement date for our last coal units.

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Existing gas-fired combustion turbine units are not subject to this rule and therefore those Company units are also not subject to this rule. On March 12, 2025, EPA Administrator Lee Zeldin announced the agency will undertake actions "reconsidering regulations on power plants (Clean Power Plan 2.0)" which could imply that these regulations will be revised at some point in the future.

Environmental Regulations and Compliance Strategy – Waste

Q. Can you please describe the relevant parts of the Resource Conservation and Recovery Act ("RCRA") as related to Coal Combustion Residuals ("CCR") management?

A. On April 17, 2015, the EPA published 40 CFR Parts 257 and 261, Disposal of CCRs from Electric Utilities, in the Federal Register under Subtitle D of the RCRA. The rules establish minimum national criteria for purposes of determining which CCR solid waste disposal facilities and solid waste management practices pose a reasonable probability of adverse effect on health or the environment under RCRA. The rule is considered self-implementing, meaning that affected facilities must certify compliance with the published standards and schedules. By codifying standards under Subtitle D, Owners and Operators are not required to obtain permits, and states are not required to adopt and implement the new rules. Instead, the rules' only enforcement mechanism is for a state or citizen group to bring a RCRA citizen suit in federal district court against any facility that is alleged to be in noncompliance with the newly promulgated minimum standards. In December 2016, the Water Infrastructure Improvements for the Nation ("WIIN") Act was passed and signed into law. Section 2031 of the legislation provides authority for state implementation of coal ash management through a state permit program in lieu of the

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1 current enforcement of the CCR Rule through the RCRA citizen-suit authority. States may
2 elect to submit a CCR permit program to the EPA for approval. The State of Michigan
3 revised its solid waste statute in late 2018 to outline a state CCR permitting program.
4 Michigan has submitted its application to the EPA for a permit program and is awaiting
5 the EPAs review of administrative completeness. In the interim, the EPA has information
6 gathering and enforcement authorities to enforce the CCR Rule as provided in the WIIN
7 Act.

8 The existence of a state permitting program allows Department of Environment,
9 Great Lakes, and Energy (“EGLE”) to issue permits under Michigan’s solid waste
10 management statute (Part 115 of the Natural Resources and Environmental Protection Act
11 of 1994 (“NREPA”), as amended) to regulate compliance schedules and activities for CCR
12 landfills and surface impoundments. Although the current state CCR permitting program
13 was passed into law and Consumers Energy is obligated to comply with the associated
14 statute, permits, and licenses, the program must be approved by the EPA on the basis that
15 it is “as protective as” the CCR Rule to avoid dual state and federal regulation. Thus,
16 similar compliance standards are required within the state permitting program, including
17 requirements to make compliance documentation publicly available, completing the work,
18 and then self-reporting by providing notifications to EGLE and posting to a publicly
19 accessible compliance website.

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1 **Q. What are the capital and/or O&M investments Consumers Energy is seeking to**
2 **recover in this case that are specifically related to RCRA compliance and/or overall**
3 **CCR Management?**

4 A. The Company's CCR management compliance strategy was approved in Case No.
5 U-18322. The major capital work for compliance has been completed. The Cost of
6 Removal ("COR") and/or O&M required for the management of CCRs under the RCRA
7 that the Company is seeking to recover can be found in Exhibits A-139 (JJK-3) and A-43
8 (RTB-4). The COR expenses represent historical expenses only. Separately, there are
9 closure activities that will continue throughout the bridge period and test year and beyond;
10 however, those expenses are COR and are not included in this filing.

11 **Environmental Regulations and Compliance Strategy – Water**

12 **Q. Can you please describe the relevant parts of the Steam Electric Effluent Guidelines**
13 **("SEEG") as related to wastewater management?**

14 A. On April 24, 2024, EPA finalized a supplemental rulemaking to strengthen discharge limits
15 for Flue Gas Desulfurization ("FGD") wastewater, bottom ash transport water, Combustion
16 Residual Leachate ("CRL"), and legacy wastewaters. FGD and legacy wastewaters are not
17 and will not be generated at Consumers Energy locations. Campbell will be retiring in 2025
18 and will comply with the cessation of coal combustion by 2028 subcategory for bottom ash
19 transport water. CRL discharge limits will impact the Campbell dry ash landfill where the
20 Company is completing a capital project to install a deep injection well to address this
21 issue. Paired with the 2024 RCRA rule, there is risk at the J.C. Weadock ("Weadock"),
22 Karn, B.C. Cobb ("Cobb"), and J.R. Whiting ("Whiting") sites. The 2024 RCRA rule does
23 not allow free liquid in closed ash landfills, but it also does not define what free liquid is.

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1 If the 2024 RCRA rule were to require installation of dewatering wells in closed landfills,
2 any wastewater generated would likely be classified as unmanaged CRL subject to arsenic
3 and mercury limits and require treatment prior to surface water discharge.

4 **Q. What are the capital and/or O&M investments Consumers Energy is seeking to**
5 **recover in this case that are specifically related to RCRA compliance and/or overall**
6 **wastewater management?**

7 A. The Company is seeking to recover costs for the installation of a deep well to be used for
8 wastewater disposal at the Campbell facility. The Campbell facility will cease generation
9 in June 2025 and on-site operations will cease by the end of 2025. Due to wastewater
10 generated during decommissioning, the sitewide National Pollutant Discharge Elimination
11 System (“NPDES”) permit will remain open through demolition. Campbell has an active
12 landfill with leachate which requires treatment/disposal. After on-site operations end, the
13 flow characteristics of the Campbell facility will change and there will be a need to manage
14 leachate differently as the current outfall location will no longer be available for use. SEEG
15 rules require zero liquid discharge of CRL no later than December 31, 2029; however,
16 because of the change in flow characteristics by the end of 2025, the Company considered
17 several options to address the ongoing leachate water, including transport for offsite
18 disposal, offsite treatment, onsite treatment and onsite disposal. Ultimately, onsite disposal
19 via a deep-injection well was selected and is currently being permitted by EGLE and
20 EPA. The Company also submitted a NPDES permit application revision on November 7,
21 2024. Please refer to page 8, line 27, and page 9, line 22 of Exhibit A-12 (RTB-3),
22 Schedule B-5.2 for projected capital expenditures in the bridge period and test year.

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SECTION III

GENERATION CAPITAL EXPENDITURES

OVERVIEW

Q. What factors does the Company consider in determining the capital investments that it will make at its generating plants?

A. The major drivers in the determination of generation capital investments are plant safety, compliance with regulations, and reliability. Consumers Energy's strategy for complying with environmental regulations was previously discussed in this direct testimony.

Q. Please describe Exhibit A-12 (RTB-3), Schedule B-5.2, Generation Capital Expenditures.

A. This exhibit presents the capital expenditures for Generation for the historical year 2024 through the projected test year - 12 months ending April 30, 2027. Exhibit A-12 (RTB-3), Schedule B-5.2, is a nine-page exhibit. Page 1 of this exhibit presents a summary of Generation capital expenditures for the Historical Period ended December 31, 2024, the Projected 16-month Bridge Period beginning January 1, 2025 and ending April 30, 2026, and the projected test year beginning May 1, 2026 and ending April 30, 2027. This summary information is broken down by Steam Power Generation, Hydraulic Power Generation, Pumped Storage Generation, and Other Production Plant. Pages 2 through 5 of this exhibit capture the same Historical Year, Bridge Period, and Test Year Generation capital expenditures information, but are presented by generating sites and environmental categories. This information is further detailed by Contractor, Labor, Materials, Business Expenses, Contingency, and Other. Page 6 of this exhibit represents a summary of pages 2 through 5 of this exhibit. Finally, pages 7 through 9 of this exhibit identify the capital projects and associated expenditures that are greater than \$1 million that contribute to the

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1 overall capital expenditures summarized on pages 1 through 6 of this exhibit. Specifically,
2 page 7 of this exhibit presents capital projects for the Historical Period ended December 31,
3 2024; page 8 of this exhibit presents capital projects for the Projected 16-month Bridge
4 Period beginning January 1, 2025 and ending April 30, 2026; and page 9 of this exhibit
5 presents capital projects for the projected test year ending April 30, 2027.

6 **Q. What project information is presented on Exhibit A-12 (RTB-3), Schedule B-5.2,**
7 **pages 7 through 9?**

8 A. Exhibit A-12 (RTB-3), Schedule B-5.2, pages 7 through 9, presents the generation type,
9 the generation unit, project type, project classification, project description, and project cost
10 information. The project type identifies whether the project is routine or non-routine.
11 Routine projects include work that is performed regularly; whereas non-routine projects
12 are typically undertaken once every 10 years or longer. The budget approval reflects the
13 status of internal approval for the project, including projected cost amount. Exhibit A-12
14 (RTB-3), Schedule B-5.2, page 7, includes both projected and actual capital project cost;
15 whereas, Exhibit A-12 (RTB-3), Schedule B-5.2, pages 8 and 9, includes only the project
16 projected amount.

17 **Q. What level of capital spending for generating plants does the Company request the**
18 **Commission to incorporate into rates in this case?**

19 A. The Company's rate relief request in this case reflects capital spending on projects for its
20 generating plants of \$145.252 million for the historical test year ended December 31, 2024
21 as shown on Exhibit A-12 (RTB-3), Schedule B-5.2, page 1, line 17, column (b);
22 \$275.408 million in the projected 16-month Bridge Period ending April 30, 2026 as
23 shown on Exhibit A-12 (RTB-3), Schedule B-5.2, page 1, line 17, column (e); and

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1 \$188.638 million in the projected test year ending April 30, 2027 as shown on Exhibit A-12
2 (RTB-3), Schedule B-5.2, page 1, line 17, column (f).

3 **Q. Has the Company included any contingency in the requested capital expenditures for**
4 **Generation?**

5 A. No. The Company no longer includes contingency in its generation projects.

6 **Q. Please explain how the Company prioritizes its capital investments within**
7 **Generation.**

8 A. In evaluating capital investments, the Company's first priority is addressing safety,
9 regulatory, compliance, and continued operation related projects. These projects are
10 considered a mandatory cost of doing business. Safety, regulatory, compliance, and
11 continued operation-related projects provide economic value to customers in that they
12 allow the units to remain in service and avoid potential derates and/or shutdown due to an
13 intervention by various regulators including Occupational Safety and Health
14 Administration ("OSHA"), EGLE, the EPA, and FERC. In order to minimize the impact
15 of these projects on customers, the Company utilizes a least cost/best fit ("LCBF") analysis
16 for the investments necessary to satisfy service quality, safety, and federal and state policy
17 requirements.

18 **Q. How does the Company determine whether other projects get approved for funding?**

19 A. In accordance with the Company's generation asset strategy for each generating unit or
20 category of generating units, economic projects that are expected to reduce ROR,
21 maintenance cost or heat rate, all else being equal, are evaluated to ensure that their
22 implementation results in a net benefit to the customer. For a project to receive approval
23 for implementation, the projected benefits of the work must have a greater value than the

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1 cost of implementing the project. In other words, the implementation of the project should,
2 at a minimum, result in a marginal customer benefit.

3 **Q. How does the Company evaluate other capital investments, such as economic**
4 **projects?**

5 A. The Company uses two financial measures, Internal Rate of Return ("IRR") and Present
6 Value Ratio ("PVR"), as a means to evaluate and prioritize projected economic projects
7 within Generation. A complex financial model was developed in-house that allows the
8 Company to calculate and measure the numerous changes that result when improvements
9 (both O&M and Capital) are made to its rate-based generating units.

10 **Q. Does the Company calculate IRRs or PVRs for all projects?**

11 A. No. The Company calculates IRRs or PVRs for economic projects that are not considered
12 required but would yield net benefits to customers. Projects required for regulatory,
13 compliance, and/or continued operations are reviewed to assure that the project is cost
14 effective and results from a reasonable evaluation of alternatives, but because the project
15 must be done for compliance and continued operation, IRR or PVR may not be calculated.
16 When evaluating project alternatives related to regulatory, compliance, and/or continued
17 operations, IRRs or PVRs may be used to rank alternatives.

18 **Q. Please explain what you mean by projects for continued operations.**

19 A. Projects for continued operations refers to projects which are necessary to allow the
20 generating unit to continue to operate through its retirement date. Alternatives for projects
21 necessary for continued operation will generally be evaluated based upon LCBF. For this
22 evaluation, one of the alternatives will include a decision to not perform the project and
23 either retire the unit earlier than projected or operate the unit at a permanent derate.

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1 **Q. How does the Company evaluate customer benefits associated with**
2 **generation-related capital investments?**

3 A. The Company uses replacement power cost estimates and PSCR impacts when evaluating
4 customer benefits. The Company also evaluates ROR and heat rate improvements, which
5 result in increased generation and/or lower cost generation.

6 **Q. How does the Company evaluate historical events which have impacted availability?**

7 A. The cause of each of the historical events impacting availability are evaluated and
8 measured, and the actions necessary to avoid the same or similar events are considered for
9 implementation. In many cases, actions necessary to prevent the event from recurring are
10 cost beneficial. The availability projections, including ROR, simply reflect the Company's
11 best estimate of the operational benefits of those corrective actions that have already been
12 taken or are planned to be taken, through the projected test year ending April 30, 2027.

13 **Q. Does the Company evaluate customer benefits associated with Outage Schedules?**

14 A. Yes, the Company uses historical market prices to evaluate timing around outages in an
15 effort to ensure the unit is available during periods in which market pricing is projected to
16 be high.

17 **Q. Is it possible that the Company could experience changes to its scheduled outages and**
18 **forecasted capital expenditures in the future?**

19 A. Yes. The Company often forecasts future actions and capital expenditures based on
20 currently available information, many months before the work is completed. To provide
21 some perspective, the outage schedule used in this case was approved in August 2023.
22 A review of the outage schedule used in this case identifies ten scheduled outages that
23 begin in May 2026 (20 months after the schedule was approved) and run through April 30,

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1 2027, 31 months later. During each of these ten scheduled outages, Consumers Energy has
2 scheduled a number of tasks to be performed. Because of the long lead times, the number
3 of outages scheduled during the test year, and the fact that several different tasks will be
4 performed during each outage, it is inevitable that some scheduled outages and forecast
5 capital expenditures will change. However, the Company has a history of prudent capital
6 investments in its generating facilities, which have been consistently supported by the
7 Commission.

8 **Q. Are there other reasons why outage schedule changes occur?**

9 A. Yes. Some of the reasons why outage schedule changes occur are: contractor availability,
10 parts availability, changes in regulations, design changes, outage scope changes, changes
11 in unit condition, and spot market prices. It is critical to point out that disallowance of
12 projected capital expenditures in electric rate cases leads to the cancellation of work scope
13 and outage plans, thus pushing needed investment to the future, continuing risk with plant
14 operations, and increasing customer cost due to lower availability.

15 **Q. Can you provide an example of when circumstances changed?**

16 A. Yes. The Company's fall 2023 outages for Karn Units 3 and 4 were originally scheduled
17 from October 1, 2023 through November 18, 2023. The Karn Unit 3 and 4 outages were
18 not performed due to availability of materials for the major work that was planned. Due to
19 the uncertainty of the retirement of Karn Units 3 and 4 as proposed in the Company's 2021
20 IRP, the preparation for these outages was not complete, including material delivery. As
21 such the planned work was deferred to 2024.

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1 **Q. Please describe how the Company determines its generation projected capital**
2 **expenditure amounts.**

3 A. Consistent with the Company's generation asset strategy, generation projected capital
4 investments support the continued safe, regulatory compliant and reliable operations of the
5 Company's electric generating fleet. Projected capital investments are informed by
6 historical and anticipated performance of the units. The reasonableness of the generation
7 capital investments is indicated by the sustained or improved performance of the
8 Company's electric generating fleet relative to: (1) the safety of the employees, contractors,
9 and community at and around the generating facilities; (2) compliance with rules and
10 regulations; and (3) reliably participating in the energy, resource adequacy, and ancillary
11 services markets.

12 **Q. How are projects identified that are discussed later in this direct testimony?**

13 A. Generation System Planners assess the equipment performance and compare that
14 assessment with the generation asset strategy for the generating unit. Upon identification
15 of a potential project, the Planner will complete a project initiation document ("PID"). This
16 document defines the issue, alternatives considered for resolution, intended benefits or
17 consequences avoided, and suggested timing and a cost estimate. The document is
18 reviewed by multiple groups for alignment and ultimately routed for approval for inclusion
19 in the Long-Term Financial Plan ("LTFP"). PIDs entered into the LTFP will typically be
20 scheduled three to five years in the future to align with outages and provide the project
21 execution teams ample time to plan and engineer.

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1 **Q. How were the projected capital expenditure amounts developed for each of the**
2 **projects discussed later in this direct testimony?**

3 A. Each project begins with the creation of a PID. The Planner will provide an initial cost
4 estimate for the project within the PID. The Planner utilizes past experience, contractor
5 cost estimates, internal estimates, Original Equipment Manufacturer (“OEM”) data, and
6 studies to provide the best estimate of the costs. This activity typically takes place three to
7 five years prior to the start of project execution.

8 **Q. How are PIDs related to Concept Approval Documents (“CADs”)?**

9 A. The PID is the mechanism utilized to allow projects to be considered for the LTFP. Once
10 the project is included in the LTFP and the project is within a year of start of execution,
11 the CAD is created. The CAD is templated from the PID and updated as necessary. The
12 CAD is then routed for approval to the designated level of management based on project
13 amount and, once approved, the project will be initiated.

14 **Q. Do adjustments to the projected capital investment amounts for each of the projects**
15 **occur prior to project implementation?**

16 A. Yes. As the project team progresses through the life cycle of a project, there are multiple
17 opportunities to better define project costs. Activities such as detailed engineering,
18 bidding, contractor involvement, and construction all allow for budgets to be better defined.
19 As this definition evolves, the projected capital investments are updated accordingly.

20 **Q. How does the Company account for uncertainties in its cost projections?**

21 A. When forecasting and budgeting for the Company’s generation projects, the Company
22 accounts for the uncertainty of less mature estimates by including contingency in its cost
23 estimates. For purposes of this rate case filing, the Company has already removed the

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1 contingency component of its generation project cost estimates before filing the case since
2 it has been disallowed in the past. The Company also utilizes industry standard cost
3 estimating practices that involve class estimates having a prescribed range of potential cost
4 outcomes based on estimate accuracy. The Commission has historically disallowed costs
5 above the lower range for certain projects and cost estimate classes.

6 **Q. What impact does this have on the Company's ability to fund needed generation**
7 **capital projects?**

8 A. If the Commission disallows both the contingency amount included in the project forecasts
9 and an amount consistent with the bottom end of the range of estimate accuracy, it is
10 virtually certain to underfund the Company's generation capital projects.

11 **2024 HISTORICAL TEST YEAR CAPITAL EXPENDITURES**

12 **Q. How does the 2024 actual capital expenditure amount of \$145.252 million compare to**
13 **the amount of capital expenditures reflected in the Company's request in Case No.**
14 **U-21585?**

15 A. In Case No. U 21585, the Company requested \$339.304 million for the 12 months ended
16 December 31, 2024. The 2024 actual capital expenditure amount of \$145.252 million is
17 \$194.052 million less than the projected amount.

18 **Q. What is the basis for the gap in projected versus actual spending?**

19 A. The reduction in the Company's actual capital expenditure amount is primarily attributable
20 to the removal of the capital expenditures for IRP solar projects (Muskegon, Spring Creek,
21 Mustang Mile, and Washtenaw) and the reduction in investment in the BESS projects. The
22 Company withdrew the requested recovery of the IRP solar generation projects from Case
23 No. U-21585 and has instead sought to recover them in its amended renewable energy plan

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1 Case No. U-21816. The removal of the investment for these projects for the 12-month
2 period ending December 31, 2025 reduced the projected capital expenditures by
3 \$130.597 million.

4 In addition, the Company identified delays in the commercial operation dates
5 (“CODs”) for the BESS projects. The projected investment amount for the 12 months
6 ended December 31, 2024 was \$39.672 million and the actual capital expenditure amount
7 was \$22.942 million, a difference of \$16.730 million. The CODs for the Weadock and
8 Iosco projects were pushed out beyond the test year in Case No. U-21585 so there was no
9 impact to the revenue requirement in the final order.

10 Also, as previously discussed in this direct testimony, the actual 2024 capital
11 expenditures do not include any River Hydro investment. The total investment on the River
12 Hydros for the 12 months ending December 31, 2024 was projected to be \$38.052 million
13 and the actual investment was only \$33.933 million. Several parties to the Company’s
14 2024 electric rate case recommended complete disallowance of the entire River Hydro
15 investment and, as such, the Company managed its investment in 2024.

16 Finally, the actual capital expenditures for Ludington for the 12-month period
17 ended December 31, 2024 came in at \$3.857 million versus the projected amount of
18 \$8.717 million. The total investment amount for Ludington was over \$20 million, however
19 a portion of the investment was recorded as a regulatory asset.³

³ See the February 28, 2025 report in Case No. U-21310.

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1 **Q. How does the compilation of capital projects on Exhibit A-12 (RTB-3), Schedule**
2 **B-5.2, page 7, compare with the 14-month bridge capital projects reflected on Case**
3 **No. U-21585, Exhibit A-12 (RTB-3), Schedule B-5.2, page 8?**

4 A. A comparison of the projects on Exhibit A-12 (RTB-3), Schedule B-5.2, page 7, with the
5 bridge period projects reflected on Case No. U-21585, Exhibit A-12 (RTB-3), Schedule
6 B-5.2, page 8, reveals that there are eleven projects on Exhibit A-12 (RTB-3), Schedule
7 B-5.2, page 7, which were not reflected on Case No. U-21585, Exhibit A-12 (RTB-3),
8 Schedule B-5.2, page 8. In addition, there were fourteen projects for the 14-month bridge
9 period that were reflected on Case No. U-21585, Exhibit A-12 (RTB-3), Schedule B-5.2,
10 page 8, that are not presented on Exhibit A-12 (RTB-3), Schedule B-5.2, page 7. The River
11 Hydro projects were not considered in this evaluation due to their removal.

12 **Q. Please discuss the 14-month bridge period capital projects that were included on Case**
13 **No. U-21585, Exhibit A-12 (RTB-3), Schedule B-5.2, page 8, that are not presented on**
14 **Exhibit A-12 (RTB-3), Schedule B-5.2, page 7.**

15 A. The following projects are not presented on Exhibit A-12 (RTB-3), Schedule B-5.2, page 7,
16 due to the fact that their actual 2024 capital expenditure amount was less than \$1 million,
17 the project was disallowed, reduced in cost or removed, or not pursued in 2024. As
18 previously discussed, the entire amount of River Hydro investment was deferred and, as
19 such, is not presented on the Company's Exhibit A-12 (RTB-3), Schedule B-5.2. In
20 addition, the entire amount of investment for the Covert Long-Term Service Agreement
21 ("LTSA") extra work was disallowed. The disposition of the other capital projects which
22 are not presented on Exhibit A-12 (RTB-3), Schedule B-5.2 is provided below:

23 Below is a list of projects for which the Company either removed or did not reflect
24 in the revenue requirement due to their COD being beyond the test year:

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Project Description	Projected Amount
Solar - 2021 Bid Event (Muskegon Solar) (250 MW)	\$ 141,387
Solar - 2022 Bid Event (Spring Creek)	\$ 108,185
Armstrong Battery Energy Storage System (IIJA Grant App)	\$ 6,341

Below is a list of projects whose projected bridge period costs were reduced or deferred by the Company and their projected amounts approved in the final order in Case No. U-21585 were less than \$1 million:

Project Description	Projected Amount ('000)	Reduced Amount ('000)
Covert Purchase of site spare generator stepup transformer	\$ 1,000	\$ (27)
Covert Cooling Tower Gearboxes	\$ 1,162	\$ 872
Covert SCR/CO Catalyst Replacement - Unit 2	\$ 1,042	\$ 142
Covert SCR/CO Catalyst Replacement - Unit 3	\$ 1,042	\$ 142
Karn Unit 3 Combustion Air Heater	\$ 2,200	\$ 214
Ludington lower penstock expansion joint Chamber water stop replacement	\$ 2,716	\$ 556

Below is a discussion of the remaining million-dollar projects whose actual 2024 capital expenditures were less than projected:

- Covert Units 1 through 3 Emerson Digital Control System (“DCS”) Evergreen (\$1,041,250). The projected 2024 spend for this project was only \$551,500 with the largest portion of the spend reflected in 2025 including the last two months of the bridge period. The actual spend in 2024 was \$530,441 so the actual spend is relatively on target. The remaining spend of \$2,156,101 in the bridge period and \$967,800 in the test year will complete the project;
- Jackson Long Term Service Agreement Extra Work Expected (\$1,366,114). During 2024, the Company spent a total of \$330,371 on this project, primarily due to moving S2 Nozzle Assy work from 2024 to 2025 because of the delay in material delivery from General Electric. \$2,115,001 is planned for the bridge period ending April 30, 2026, and only \$0.315 million is planned for the test year ending April 30, 2027;
- Zeeland Phase I Gas Turbine Advanced gas path replacement and axial fuel staging (\$8,631,164) and LTSA Extras not included in the contract. The total spend for these projects and the long-term service agreement in 2024 was \$21,506,968. The total projected amount for these three projects for the 14-month bridge period was \$29,505,861 with \$9,941,250 of that projected amount reflected in January and February of 2025. As such, the actual spend for all the work associated with the LTSA was greater than the projected amounts;
- Karn Unit 4 DCS Evergreen (\$1,449,204). The Company spent \$125,388 in 2024 versus the projected 2024 amount of \$1,363,000. The Company underspent on the project because it didn’t employ Emerson Field Engineering Service time, rather the Company completed many of the items internally and, therefore, avoided a portion of the investment; and

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- Ludington 1-6 distributed control system control relay replacement (\$1,623,526). During 2024 the Company spent \$670,551 of the total 2024 projected amount of \$1,214,360. The remaining bridge period amount was forecast to be spent in January and February of 2025. The Company is projected to spend \$3,608,477 in the 16-month projected bridge period and \$2,906,676 in the projected test year. The project was intentionally delayed in order to align it with the large corrective project outage schedule. This project was originally scheduled to execute in 2025 through 2027. The Company's current plans are to execute the project in 2026 through 2029 in order to minimize the impact on unit availability.

Q. Please discuss the 2024 capital projects that were not included in Case No. U-21585, Exhibit A-12 (RTB-3), Schedule B-5.2, page 8, that are presented on Exhibit A-12 (RTB-3), Schedule B-5.2, page 7.

A. The disposition of these capital projects is presented below:

- Covert Heat Recovery Steam Generator ("HRSG") Expansion Joint Replacements (\$1,284,244). There was no projected amount for 2024, however the work was required as a result of equipment (seal) failure. The seals for all three units failed, resulting in hot flue gas blowing out of the unit. This presented a safety issue, as there were areas around the units that a person could not safely approach due to excessive heat and exhaust gas inhalation. In addition, the site was also experiencing issues where some of the instrumentation cables were failing due to the excessive heat melting their insulation. Finally, because of the seal failures, the insulation failed in the floor sections of the duct where these penetrations are located. To replace the expansion joints and not address the insulation would have resulted in a quick recurrence of the expansion joints failing. The work to remove liners and replace the insulation was more costly than the expansion joint work, but a necessary part of the overall replacement. Project closeout for this project will be completed in the bridge period as discussed later in this direct testimony;
- Covert LTSA Extra Work Unit 2 (\$1,339,561). The projected amount for 2024 was \$750,000 and the amount projected for 2025 was \$12,576,300. The actual amount came in higher due to pulling some of the investment forward, thereby reducing the projected amount for the 16-month bridge period to \$12,153,320. This project will be discussed in more detail later in this direct testimony;
- Jackson Units 1-6 Feedwater ("FW") Desuperheater Valve (\$1,871,081). The scope of this project was to install FW control valves and separate lance spray nozzle assemblies that spray small amounts of water into steam flow continuously. The HRSG 1-6 superheat ("SH") Steam Desuperheater FW valves have had very short life spans since original construction. There were several issues that caused the valves to wear out quickly. The valves inherently

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1 cycled frequently open and closed due to the boiler running close to high
2 pressure (“HP”) Steam Outlet temperature setpoint at gas turbine baseload,
3 without duct firing. This has been reduced recently by a study completed by
4 engineering and GE to allow the HP Steam temperature to be increased from
5 the original 750 degrees Fahrenheit up to 770 degrees Fahrenheit. This change
6 did cause the valves to cycle open/close less frequently, but it did not result in
7 a substantial improvement in valve life. The brunt of the wear is absorbed by
8 the High Pressure Feedwater Autoblock valve, which when it begins to leak by,
9 causes the SH Steam temperature to fall. The HP FW Control Valve wears out
10 quickly as well. Typically, when this occurs the leak by accelerates quickly to
11 the point which the manual HP FW isolation valve upstream must be closed
12 when the unit is not duct firing to maintain adequate superheated steam
13 temperature. The projected amount for 2024 was \$828,100. However, this
14 projected cost was not based upon a solicitation. Upon receiving proposals it
15 was learned that the lowest bid amount was approximately \$1 million higher
16 than the projected cost. The project payback is still relatively short as the plant
17 was experiencing approximately three failures annually at a cost greater than
18 \$1 million;

- 19 • Zeeland Site Spare Generator Step-Up (“GSU”) (2,039,715). The scope of this
20 project is to purchase a spare GSU. The projected spend was \$589,607 for the
21 bridge period and \$2,340,637 for the test year. The project is described in more
22 detail later in this direct testimony; and
- 23 • Zeeland Phase 2 599 and 699 345 kV breaker replacement (\$1,855,883). The
24 scope of this project is to replace the 599 and 699 circuit breakers with a type
25 which does not exhibit the failure modes exhibited by the existing design. The
26 existing breakers have a critical design flaw such that an individual pole or poles
27 may not latch open when required. The pole’s failure to latch open has the
28 potential to result in lost generation, loss of power to the entire Zeeland
29 Substation, and/or equipment damage. The projected amount for 2024 was
30 \$319,559 and was originally scheduled for execution in 2023. However, it was
31 pushed to 2024 for various reasons including the fact that the breaker delivery
32 and GSU project delivery missed their 2023 installation targets.

33 The following four projects were all implemented to support the separation of Karn
34 Units 1 and 2 from Karn Units 3 and 4. This unit separation work was presented in the
35 Company’s 2021 IRP and the Company’s 2023 Electric Rate Case No. U-21389 but was
36 not appropriately reflected in the Company’s 2024 Electric Rate case, Case No. U-21585
37 as it was erroneously reflected as decommissioning/cost of removal. Each of these projects

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1 were required to operate Karn Units 3 and 4 independent of Karn Units 1 and 2 following
2 their retirement on May 31, 2023.

- 3 • New Electrical System from Weadock Sub for Karn 3 and 4 (\$1,523,648);
- 4 • Discharge Line Reroute for K 3 and 4 Sump Water (\$1,905,159);
- 5 • New building to house new fire water system (\$1,019,275); and
- 6 • New 46kV to 4160 transformer to re-power facilities (\$3,065,403).

7 The projected spend for the bridge period for the following two projects was less than
8 \$1 million in the Company's original filing but the projected spend was updated to be
9 greater than \$1 million and presented in Staff Exhibit No. S-16.1 (RDB-2), page 1 of 2.

- 10 • Karn 3&4 Tank Farm Heating Line Replacement (\$1,216,552); and
- 11 • Netmation (MHPSA Operating System & 4S) - Unit 1-3 (\$5,046,654).

12 **PROJECTED 16-MONTH BRIDGE PERIOD CAPITAL**
13 **EXPENDITURES**

14 **Q. How does the projected 16-month bridge period capital expenditure of**
15 **\$275.408 million compare to the amount of capital requested by the Company in**
16 **Case No. U-21585 for 2025?**

17 A. The 16-month bridge period projected capital expenditure amount of \$275.408 million
18 compares favorably with the \$724.728 million for the 14-month period beginning
19 January 1, 2025 through February 28, 2026. While the difference is quite large, it is
20 important to call out that the Company's initial request in Case No. U-21585 for the
21 14-month period beginning January 1, 2025 through February 28, 2026 included
22 \$373.076 million for three solar projects which the Company has since removed and
23 moved to its Renewable Energy Plan Case No. U-21816 and also included \$96.582 million
24 for River Hydro investments. In addition, a portion of the projected BESS investment was

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1 moved out beyond the test year in Case No. U-21585 and, as a result, that investment had
2 no material impact on the revenue requirement used to establish rates. A detailed
3 discussion of the BESS projects is presented in Company witness Clark's direct testimony.
4 A compilation of the 16-month bridge period projects which have projected capital
5 expenditure amounts greater than \$1 million is presented on Exhibit A-12 (RTB-3),
6 Schedule B-5.2, page 8, and an explanation of the project changes is described in more
7 detail later in this direct testimony.

8 **Q. How does the compilation of 16-month bridge period capital projects on Exhibit A-12**
9 **(RTB-3), Schedule B-5.2, page 8, compare with the test year capital projects reflected**
10 **on Case No. U-21585, Exhibit A-12 (RTB-3), Schedule B-5.2, page 9?**

11 A. A comparison of the 16-month bridge period capital projects on Exhibit A-12 (RTB-3),
12 Schedule B-5.2, page 8, with the test year projects reflected on Case No. U-21585, Exhibit
13 A-12 (RTB-3), Schedule B-5.2, page 9, reveals that there are 12 projects on Exhibit A-12
14 (RTB-3), Schedule B-5.2, page 8, which were not reflected on Case No. U-21585, Exhibit
15 A-12 (RTB-3), Schedule B-5.2, page 9. In addition, there were 11 projects for the
16 12-month period ending February 30, 2026 that were reflected on Case No. U-21585,
17 Exhibit A-12 (RTB-3), Schedule B-5.2, page 9, that are not presented on Exhibit A-12
18 (RTB-3), Schedule B-5.2, page 8. The River Hydro projects were not considered in this
19 evaluation due to their removal.

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Q. Please discuss the test year capital projects that were included on Case No. U-21585, Exhibit A-12 (RTB-3), Schedule B-5.2, page 9, that are not presented on Exhibit A-12 (RTB-3), Schedule B-5.2, page 8.

A. The following projects are not presented on Exhibit A-12 (RTB-3), Schedule B-5.2, page 8, due to the fact that the projected bridge period capital expenditure amounts are now less than \$1 million or the project is not being pursued in the bridge period. The disposition of these capital projects is presented in the table below:

Site	Project	Disposition
Covert	Cooling Tower Gearboxes	project spend reduced in U-21585
Covert	Unit 1 - LTSA Capital - Extra work not included in contract	Project disallowed in U-21585
Covert	Office Space Consumers Energy Warehouse with Loading Dock	Project disallowed in U-21585
Karn 4	Karn 4 Replacement of Ductwork Insulation and Lagging	Project disallowed in U-21585
Zeeland	Generator Rewinds	Inspection determined work not required
Ludington	Ludington Intake Gate and Gate House Mechanical Replacement	\$1.732 million in bridge period and test year
Ludington	Station Power Transformer Life Cycle Management	\$1.407 million in bridge period and test year
BESS	Armstrong Battery Energy Storage System (IIJA Grant App)	Project COD delayed to beyond test year
Solar IRP	Solar - 2021 Bid Event (Muskegon Solar) (250 MW)	Moved to the Renewable Energy Plan
Solar IRP	Solar - 2022 Bid Event (Spring Creek)	Moved to the Renewable Energy Plan
Solar IRP	Solar - 2020 Bid Event (Washtenaw Solar) (150 MW)	Moved to the Renewable Energy Plan

Q. Please identify the 16-month bridge period capital projects that were not included on Case No. U-21585, Exhibit A-12 (RTB-3), Schedule B-5.2, page 9, that are presented on Exhibit A-12 (RTB-3), Schedule B-5.2, page 8.

A. The bridge period capital projects that were not included on Case No. U-21585, Exhibit A-12 (RTB-3), Schedule B-5.2, page 9, are presented in the table below:

Line No.	Site	Project Description
1	Covert	Load Commutated Inverter Static Frequency Converter
2	Jackson	Purchase of site spare GSU
3	Jackson	LM6000 ESN 191-306 HP Turbine S2 Nozzle replacement
4	Jackson	LTSA Capital - Extra work not included in contract
5	Zeeland	Unit 5 GSU Transformer
6	Karn 3	Combustion Air Heater Replacement
7	Karn 4	Combustion Air Heater Replacement
8	Karn 4	ID Fan Inlet Damper Replacements
9	Ludington	Replace Lower Penstock Expansion Joint
10	Ludington	Station Water Dschrg Isolation Valve
11	Admin	Wastewater Treatment System

The basis for these projects will be discussed in more detail later in this direct testimony.

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1 **Q. Is the projected capital expenditure amount of \$275.408 million for the 16-month**
2 **bridge period ending April 30, 2026, on Exhibit A-12 (RTB-3), Schedule B-5.2, page 1,**
3 **column (e), consistent with the Company's generation asset strategy?**

4 A. Yes. Based upon a review of the projected capital expenditure presentation on
5 Exhibit A-12 (RTB-3), Schedule B-5.2, pages 2 and 3, lines 1 through 84, column (h),
6 \$70.614 million will fund BESS projects, \$171.787 million of that total capital expenditure
7 amount will be used at the Company's natural gas generating facilities which includes
8 Covert, Jackson, Zeeland, and Karn Units 3 and 4. In addition, \$15.225 million will fund
9 various projects at the LPS facility. With the exception of the BESS projects, a detailed
10 discussion of the various projects for each generating unit or group of generating units will
11 be provided later in this direct testimony. The BESS projects will be discussed in the direct
12 testimony of Company witness Clark.

13 **PROJECTED TEST YEAR CAPITAL EXPENDITURES**

14 **Q. Is the projected capital expenditure amount of \$188.638 million for the test year**
15 **ending April 30, 2027, on Exhibit A-12 (RTB-3), Schedule B-5.2, page 1, column (f),**
16 **consistent with the Company's generation asset strategy?**

17 A. Yes. Based upon a review of the projected capital expenditure presentation on
18 Exhibit A-12 (RTB-3), Schedule B-5.2, pages 2 and 3, lines 1 through 84, column (j),
19 \$26.392 million will fund BESS projects, \$137.913 million of that total capital expenditure
20 amount will be used at the Company's natural gas generating facilities which includes
21 Covert, Jackson, Zeeland, and Karn Units 3 and 4. In addition, \$13.282 million will allow
22 the Company to complete various regulatory, reliability, and infrastructure projects
23 necessary to support the 50-year license extension at Ludington granted by FERC in 2019.

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1 Except for the BESS projects, a detailed discussion of the various projects for each
2 generating unit or group of generating units will be provided later in this direct testimony.

3 The BESS projects will be discussed in the direct testimony of Company witness Clark.

4 **Campbell Units 1, 2, and 3**

5 **Q. Please explain the Company's projected capital investment for the 16-month**
6 **projected bridge period ending April 30, 2026 and projected test year ending April**
7 **30, 2027 for Campbell Units 1, 2, and 3.**

8 A. The Company does not plan to invest any capital in the Campbell units during the bridge
9 period or test year, as reflected on Exhibit A-12 (RTB-3), Schedule B-5.2, page 2, lines 1
10 and 8. As presented on Exhibit A-43 (RTB-4), page 3, lines 1 and 2, and as discussed later
11 in this direct testimony, the Company has projected modest amounts of major maintenance
12 to ensure that these units were able to operate through their retirement date of May 31,
13 2025.

14 **Covert Plant**

15 **Q. Please explain the Company's projected capital investment for the 16-month**
16 **projected bridge period ending April 30, 2026 and projected test year ending April 30,**
17 **2027 for Covert.**

18 A. The Company plans to invest a total of \$67.545 million in the 16-month bridge period and
19 \$61.443 million in the test year at the Covert Plant. These capital investments will be
20 facilitated by nine-day outages at Covert Units 1 through 3 in the spring and fall of 2025
21 as well as longer unit outages for major inspections. Covert Unit 1 has a 59-day outage
22 scheduled to begin on September 1, 2025, Covert Unit 3 has a 59-day outage scheduled to

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begin on March 15, 2026, and Covert Unit 2 had a 59-day outage scheduled that began on March 1, 2025.

Q. Please explain the Company's projected capital investment for the 16-month bridge period ending April 30, 2026 for the Covert Plant.

A. The Company plans to invest a total of \$67.545 million in the bridge period on the Covert Plant, as shown on Exhibit A-12 (RTB-3), Schedule B-5.2, page 2, line 43, column (h).

Q. What is the basis for the projected \$67.545 million capital investment in the 16-month projected bridge period?

A. The projected \$67.545 million capital investment in the projected bridge period will fund numerous projects at the Covert Plant. Seven of these projects are greater than \$1 million, and are presented on Exhibit A-12 (RTB-3), Schedule B-5.2, page 8, lines 1 through 7.

The basis for these six projects is described below:

- Load Commutated Inverter ("LCI") Static Frequency Converter ("SFC") Replacements (\$1,305,000). This project spans the 16-month bridge period and the test year, and its basis is included in my discussion of the test year capital projects for Covert;
- Purchase of site spare GSU (1,500,000). This project spans the 16-month bridge period and the test year, and its basis is included in my discussion of the test year capital projects for Covert;
- Netmation (Operating System & 4S) – Units 1 through 3 (\$2,921,689). This project spans the 16-month bridge period and the test year, and its basis is included in my discussion of the test year capital projects for Covert;
- Covert Units 1 through 3 Emerson DCS Evergreen (\$2,156,101). This project spans the 16-month bridge period and the test year, and its basis is included in my discussion of the test year capital projects for Covert; and
- Covert Plant LTSA (\$26,246,048). This project spans the 16-month bridge period and the test year, and its basis is included in my discussion of the test year capital projects for Covert;
- Covert Unit 2 LTSA extra work (\$12,153,320). The LTSA extra work is defined as the work that is not covered under normal planned maintenance in

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the LTSA. Based on historical outage experience there are typical discovery items found on this style of gas turbines that are not part of the LTSA planned maintenance scope. Some of the typical items not covered under the LTSA that need to be addressed are labor and material to replace the following: blading, ammonia delivery system, Selective Catalytic Reduction (“SCR”) catalyst, turbine rotors, cooling towers, and turbine cooling air cooler. The major inspection on Covert Unit 2 began on February 1, 2025, and major work includes generator inspection, replacement of the generator hydrogen seals, generator rewedge, diaphragm repairs, steam turbine and generator bearing repairs, and HP stop and control valve disassembly, inspection, cleaning, and repair. The Company’s LTSA with Mitsubishi Electric Power Products, Inc. (“MEPPI”) does not cover this scope of work; and

- Covert Unit 3 LTSA extra work (\$9,009,801). The LTSA extra work is defined as the work that is not covered under normal planned maintenance in the LTSA. Based on historical outage experience there are typical discovery items found on this style of gas turbines that are not part of the LTSA planned maintenance scope. Some of the typical items not covered under the LTSA that need to be addressed are labor and material to replace the following: blading, ammonia delivery system, SCR catalyst, turbine rotors, cooling towers, and turbine cooling air cooler. This project spans the 16-month bridge period and the test year, and its basis is included in my discussion of the test year capital projects for Covert.

The following projects are less than \$1 million, but are important to reliability:

- Covert Unit Cooling Tower Gearboxes (\$675,000). This project spans the 16-month bridge period and the test year, and its basis is included in my discussion of the test year capital projects for Covert;
- Gas Compressor Controls Replacement (Programmable Logic Controller (“PLC”) replacement) (\$144,000). This project spans the 16-month bridge period and the test year, and its basis is included in my discussion of the test year capital projects for Covert;
- HRSG Expansion joint replacement (\$450,000). This project spans the 16-month bridge period and the test year, and its basis is included in my discussion of the test year capital projects for Covert;
- Balance of Plant (“BOP”) Valves – Covert Units 1 through 3 (\$1,105,200 total). These projects span the 16-month bridge period and the test year, and their basis is included in my discussion of the test year capital projects for Covert;
- Gas turbine generator and steam turbine generator auto voltage regulator – Covert Units 1 and 3 (\$750,000 each). These projects span the 16-month bridge period and the test year, and their basis is included in my discussion of the test year capital projects for Covert;

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- Covert Units 1 through 3 MTX High Voltage Bushing – GSU (\$1,379,700 total). These projects span the 16-month bridge period and the test year, and their basis is included in my discussion of the test year capital projects for Covert;
- Linear Variable Differential Transformers (“LVDT”) Positioning Sensor – Unit 2 Fuel Control Valves (\$715,500). The scope of this project is to replace the Yokogawa 5516 mechanical type position sensors with LVDTs. The replacement is to include the following devices, Main “A” pressure control fuel valve sensor, Main “B” pressure control fuel valve sensor, Main flow control fuel valve sensor, Pilot pressure control fuel valve sensor, and the Pilot flow control fuel valve sensor and compressor bypass actuator. The benefits of this project include reduced maintenance, improved accuracy, and higher long-term reliability due to the removal of the mechanical linkages and converting to a non-contact mechanism;

The Covert Mitsubishi Power Gas turbines are equipped with Yokogawa 5516 mechanical linkage type position sensors. The Yokogawa position sensors are used to detect the position of the fuel control valves, bypass valve actuators, and the Inlet Guide Vanes. These valves and their position are critical as they control turbine output which allows more load on the generator and meets load demand. The Yokogawa 5516 position sensors are obsolete, and Yokogawa has announced that the 5516 position sensors are no longer manufactured as of March 31, 2015, no longer supported, and parts are no longer available. Mitsubishi Power recommends eliminating the Yokogawa mechanical linkage position sensors;

- LVDT Positioning Sensor – Unit 1 Fuel Control Valves (\$253,500). This project spans the 16-month bridge period and the test year, and its basis is included in my discussion of the test year capital projects for Covert;
- LVDT Positioning Sensor – Unit 3 Fuel Control Valves (\$253,500). This project spans the 16-month bridge period and the test year, and its basis is included in my discussion of the test year capital projects for Covert;
- Small Site Capital (\$380,000). This project spans the 16-month bridge period and the test year, and its basis is included in my discussion of the test year capital projects for Covert;
- Covert Base Outage Capital (\$774,000). Base outage capital covers the replacement parts and issues found during turbine/generator inspections and the major discovery issues found during annual unit outages;
- 3A Circ Pump/Motor Replacement (\$630,000). The Circulating Water Pump Replacement project is a critical initiative aimed at replacing the Unit 3A circulating water pump and motor, which have been in operation for over 20 years and have reached the end of their service life based on failure data

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compiled from the rest of the circulating water pumps on site. This replacement is necessary to maintain plant reliability and avoid potential unit derates;

- Covert – high energy piping surveillance (“HEPS”)/ flow accelerated corrosion (“FAC”)/ deaerator and its storage tank (“DAST”) Inspections (\$327,500). This project aims to bring the Covert site into compliance with existing corporate governance on G-A-313, G-A-314, and G-A-315 programs. Compliance with these programs ensures the safe operation of the site and provides outage scheduling flexibility by transitioning from a 12-month operating certificate to 2-year and 3-year operating certificates. The project is essential to maintain the ability to implement 2-year and 3-year operating certificates. Failure to perform the required inspections would limit the unit to a 12-month operating certificate, necessitating a full inspection before the unit can be certified to operate;
- Units 1,2,3 North American Electric Reliability Corporation (“NERC”) Relay Replacements and Test Switch Installation (\$685,712). This project spans the 16-month bridge period and the test year, and its basis is included in my discussion of the test year capital projects for Covert;
- Excitation Replacement (\$263,833). The scope of this project is the replacement of the steam turbine exciters. The existing excitation equipment is obsolete, and the gas turbine exciters have already been replaced. A failure of the steam turbine exciter could lead to both generators on the unit being out of service until replacements can be found with a typical lead time of 18-24 months; and
- Twenty-five additional projects at Covert totaling \$3.043 million which support safety, security, and reliability, with each project representing \$243,000 or less in capital expenditures. These projects include gas turbine wheel flame detectors, gas turbine evaporator media, plant fuel gas bypass system, ammonia fan replacements, actuator replacements, and unit 1 Power Distribution Center (“PDC”) battery replacement.

Q. What is the basis for the projected \$61.443million capital investment in the projected test year?

A. The projected \$61.443 million capital investment in the projected test year will fund numerous projects at the Covert Plant. Six of these projects are greater than \$1 million, and are presented on Exhibit A-12 (RTB-3), Schedule B-5.2, page 9, lines 1 through 6. The basis for these projects is described below:

- LCI SFC Replacements (\$2,610,000). The scope of this project is to replace the two SFCs which are both original to the plant’s construction in 2001. The

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1 replacement of the SFC controls is required to mitigate the significant risk of
2 failure due to obsolescence, ensure operational reliability, and align with
3 manufacturer recommendations. The Covert Generating Station Static
4 Frequency Converter Controls Replacement project is essential to address
5 significant operational and reliability issues stemming from the obsolescence
6 of the current SFC controls. The concept approval document for this project is
7 attached as Exhibit A-46 (RTB-7);

- 8 • Purchase of site spare GSU transformer (\$5,910,000). Covert Generating
9 Station consists of three gas turbine powered plants and three steam turbine
10 powered plants placed in a one-on-one combined cycle configuration. The
11 units transmit their power to the grid via GSU transformers. Each gas turbine
12 powered unit feeds the secondary winding of a three-winding transformer,
13 while the associated steam powered unit feeds the tertiary winding of the
14 transformer. The GSU is rated for 500 MVA with forced oil and forced air. If
15 a GSU were to fail, then the associated turbines would not be able to transmit
16 power and would not be able to generate market value for Consumers Energy
17 and its customers. The lead time for a GSU is currently three-to-four years and
18 spare units at other facilities typically do not exist, especially for this more
19 unique design application;

20 This project provides a spare GSU for Covert which 1) Greatly reduces unit
21 downtime in the event of GSU issues or failure requiring removal and lowers
22 the total financial losses in such events; 2) Allows for easier engineering design
23 and planning to install a spare or replacement GSU ahead of any emergent
24 installation needs; 3) Mitigates potential issues from installing GSUs not
25 specifically designed for this location, system, or application and/or doing it
26 multiple times in a short time period; 4) Would allow for Consumers Energy to
27 enter lease agreements with other utilities who may be in need of a spare to
28 recover some costs of the spare purchase over time; and 5) The oil analysis of
29 Covert transformers revealed the presence of chemicals for corrosive
30 sulfur. Mitigating actions are being taken, however, this failure mode puts these
31 transformers at increased risk of failure. The concept approval document for
32 this project is attached as Exhibit A-47 (RTB-8);

- 33 • Netmation (Operating System & 4S) (\$8,843,713). The Covert gas generating
34 station, operational since 2004, faces critical challenges with its outdated
35 control systems. These challenges impact both operational efficiency and
36 cybersecurity, necessitating an urgent upgrade to modern standards. The scope
37 of this project is an extensive upgrade of the Covert Mitsubishi Turbine Control
38 System to the latest version of Netmation, which includes the replacement of
39 hardware, input/output ("I/O") modules, servers, workstations, network
40 switches, and software to the latest architecture. The concept approval
41 document for this project is attached as Exhibit A-48 (RTB-9);
- 42 • Covert Plant LTSA (\$18,811,878). This is the capital portion for Mitsubishi
43 negotiated services that cover the planned normal maintenance of each

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1 generating unit. The projected capital expenditures are based upon variable fees
2 paid to Mitsubishi for maintenance services which are based on an Effective
3 Fired Hour basis pursuant to the LTSA. Unlike the GE LTSAs for the Jackson
4 and Zeeland plants, there are no milestone payments associated with the fee
5 structure for the Mitsubishi LTSA. Based on the OEM's operating and
6 historical experience, if the Company executes the normal planned maintenance
7 and inspections according to the recommended schedules, the Company will
8 mitigate unexpected pre-mature failures of the equipment. This will help
9 maximize availability and, as a result, optimize customer value for the site.
10 Normal maintenance will ensure the Company continues reliable operation of
11 the units. During the bridge period and test year, the Company will be
12 conducting major inspections on all three generating units, and a portion of the
13 work to be performed is not covered in the LTSA, rather it is covered in the
14 LTSA extra work as described below;

- 15 • Covert Unit 1 LTSA extra work (\$9,524,986). The LTSA extra work is defined
16 as the owner's obligations per the LTSA division of responsibility for work
17 performed by the OEM. The Covert LTSA outlines a division of responsibility,
18 with many items falling under the owner's responsibility to purchase or furnish
19 to the OEM for completing the work scope designated by the LTSA. These
20 items include, but are not limited to: (i) Required crane rentals to support
21 rigging and moving various pieces and parts, (ii) Office and break trailer rentals
22 for personnel onsite during the outage, (iii) Restroom and wash facilities for
23 onsite personnel supporting the outage, (iv) Drinking water, (v) Trailer rentals
24 for moving parts and pieces to designated laydown areas, (vi) Support structure
25 assembly for the generator field when it is removed from the generator,
26 (vii) Removal of the building wall for generator field removal,
27 (viii) Scaffolding and insulation services, (ix) Generator electrical testing.
28 These items are not covered by the LTSA but are necessary to support the LTSA
29 work scope. All parts required for the generators and the steam turbine are not
30 covered by the LTSA but are essential for executing the outage. Some of these
31 parts are consumable, while others are deemed unusable per inspections
32 performed during the outage. Any parts damaged during disassembly that are
33 required to perform the LTSA scope of work would also be replaced. Examples
34 include bolting, valve assemblies, gaskets, thrust shim plates, and steam turbine
35 packing. The labor to install packing and the resulting steam path alignment
36 activities are also not covered by the LTSA but are necessary to perform the
37 work scope per the LTSA. Additionally, once the steam turbine, gas turbine,
38 and generators are disassembled and inspected, historical outage experience and
39 industry experience indicate that many items will need to be repaired that are
40 not covered by the LTSA. These items include, but are not limited to: (i) Steam
41 turbine rotor repairs, (ii) Steam turbine diaphragm repairs, (iii) All bearing
42 repairs for the gas turbine, steam turbine, and generators, (iv) Hydrogen seal
43 repairs, (v) Steam turbine shell repairs, (vi) Collector ring machining, and
44 (vii) Compressor hook fit repairs. The major inspection for Covert Unit 1
45 begins on September 1, 2026, and ends on October 30, 2026. Consumers
46 Energy used the historical expenses for these items incurred by the previous

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owner of the plant and escalated the amounts for inflation. Additionally, current plant performance and previous outage reports were reviewed to predict as close as possible any additional work scope that would be required to restore the units to necessary reliability and performance standards while reducing any risk to the unit as much as practical. Consumers Energy also predicted that some repairs that were deferred by previous owners will have degraded to a point that repairs are now prudent. These were all combined to establish the Company's first outage scopes and budgets for the Covert units; and

- Covert Unit 3 LTSA extra work (\$4,093,234). The LTSA extra work is defined as the owner's obligations per the LTSA division of responsibility for work performed by the OEM. The Covert LTSA outlines a division of responsibility, with many items falling under the owner's responsibility to purchase or furnish to the OEM for completing the work scope designated by the LTSA. These items include, but are not limited to: (i) Required crane rentals to support rigging and moving various pieces and parts, (ii) Office and break trailer rentals for personnel onsite during the outage, (iii) Restroom and wash facilities for onsite personnel supporting the outage, (iv) Drinking water, (v) Trailer rentals for moving parts and pieces to designated laydown areas, (vi) Support structure assembly for the generator field when it is removed from the generator, (vii) Removal of the building wall for generator field removal, (viii) Scaffolding and insulation services, (ix) Generator electrical testing. These items are not covered by the LTSA but are necessary to support the LTSA work scope. All parts required for the generators and the steam turbine are not covered by the LTSA but are essential for executing the outage. Some of these parts are consumable, while others are deemed unusable per inspections performed during the outage. Any parts damaged during disassembly that are required to perform the LTSA scope of work would also be replaced. Examples include bolting, valve assemblies, gaskets, thrust shim plates, and steam turbine packing. The labor to install packing and the resulting steam path alignment activities are also not covered by the LTSA but are necessary to perform the work scope per the LTSA. Additionally, once the steam turbine, gas turbine, and generators are disassembled and inspected, historical outage experience and industry experience indicate that many items will need to be repaired that are not covered by the LTSA. These items include, but are not limited to: (i) Steam turbine rotor repairs, (ii) Steam turbine diaphragm repairs, (iii) All bearing repairs for the gas turbine, steam turbine, and generators, (iv) Hydrogen seal repairs, (v) Steam turbine shell repairs, (vi) Collector ring machining, and (vii) Compressor hook fit repairs. The major inspection on Covert Unit 3 begins on March 15, 2026, and major work includes generator inspection, replacement of the generator hydrogen seals, generator rewedge, diaphragm repairs, steam turbine and generator bearing repairs, and HP stop and control valve disassembly, inspection, cleaning, and repair. The Company's LTSA with MEPPi does not cover this scope of work. Consumers Energy used the historical expenses for these items incurred by the previous owner of the plant and escalated the amounts for inflation. Additionally, current plant performance and previous outage reports were reviewed to predict as close as

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possible any additional work scope that would be required to restore the units to necessary reliability and performance standards while reducing any risk to the unit as much as practical. Consumers Energy also predicted that some repairs that were deferred by previous owners will have degraded to a point that repairs are now prudent. These were all combined to establish the Company's first outage scopes and budgets for the Covert units.

The following projects are less than \$1 million, but are important to reliability:

- Gas Compressor Controls Replacement PLC replacement (\$576,000). Gas Compressors (two in total) operate using a local control network consisting of a human machine interface ("HMI") (Panel View 1000) and Allen Bradley PLC five controllers. This equipment has reached end of life and replacements are no longer available. The Covert site currently has one failed board in service. This project would utilize existing panels and replace the equipment with an Allen Bradley ControlLogix solution and PanelView Plus 7;
- HRSG Joint replacement (\$360,000). The scope of this project is to replace the vertical round expansion joint between the combustion turbine and the building and the HRSG. The Covert Generating Station HRSG expansion joint replacement project addresses the critical issue of aging expansion joints on all three units. These joints have a design life of 6-8 years and are typically replaced during turbine major outages. However, the existing expansion joints will be at least four years beyond their design life if replacement is delayed until the next major outage. This significantly increases the probability of failure, which could start as a small tear detectable by thermography but could also result in a large rip. Such failures would allow exhaust gases to bypass the stack and environmental monitoring equipment, releasing high-temperature gas inside the building, posing a personnel hazard and significantly impacting overall heat rate efficiency. A failure of the expansion joint could force the unit offline for 30 days until it is replaced, potentially resulting in a month of downtime if the failure is severe;
- Plant Replace Sulfuric Sodium Hypo and Building (\$600,000). The project involves replacing the existing sulfuric acid and sodium hypochlorite dosing systems and the building housing these systems at Covert. The current sodium hypochlorite system, in operation since 2004, has experienced over 60 documented failures, leading to chemical releases and hazardous cleanup situations. The system has surpassed its expected life cycle, posing increased risks of employee exposure, injury, and environmental contamination. The primary objective is to replace the aging sodium hypochlorite and sulfuric acid dosing systems and their housing structure to mitigate the risks associated with chemical spills and exposure to hazardous vapors. By separating the dosing systems, the potential for a combined spill creating chlorine gas is significantly reduced;

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- Unit 1 Cooling Tower Gearboxes (\$675,000). The Covert Generating Station Cooling Tower Fan Gearbox Replacement Project addresses critical operational issues stemming from the end-of-life status of gearboxes after over 20 years of service. These gearboxes are essential for cooling tower fan operations, affecting the station's overall efficiency and reliability. The scope of this project is to replace the existing cooling tower gearboxes with gearboxes from the same manufacturer, an alternative that avoids additional modifications. Covert operates three 6-cell cooling towers corresponding to each of its units. These cooling towers play a crucial role in the station's operational efficiency by facilitating the removal of residual heat from circulating water. This process is essential after the water has been utilized for condensing steam produced by the steam turbines. Operational challenges with the gearboxes include increased gearbox failures, inadequate heat removal due to malfunctioning cooling tower fans, and obsolete motor starters; and
- Covert Units 1 through 3 Emerson DCS Evergreen (\$967,800). The scope of this project is to upgrade the DCS to the latest version in order to enhance security, gain compliance with enterprise standards, and achieve technological advancement. Covert, which has been operational since 2004, faces significant challenges with its Emerson Ovation DCS. The system's obsolescence, cybersecurity risks, and operational inefficiencies necessitate an urgent upgrade to the latest version to enhance reliability, security, and compliance with regulatory standards. The DCS that controls all equipment in the plant (along with the Mitsubishi gas turbine controls), is Emerson Ovation DCS. It was upgraded about 10 years ago to the current version. Emerson Ovation version 3.5.1 is no longer supported by Emerson or Microsoft. The Emerson Ovation version 3.5 system entered a retired status in June 2019. The Windows operating systems that are used by this version of Ovation are Windows 7 and Windows Server 2008R2. Microsoft ended extended support of Server 2008R2 in January 2020.

The generation plant control systems are an important part of the nation's Critical Infrastructure and fall under NERC Critical Infrastructure Protection requirements. To keep the Company's control systems secure, Consumers Energy must patch the operating systems and applications that run its plants. The Company is no longer able to patch and maintain these operating systems, such as Microsoft Windows, or applications, such as Ovation, when they are no longer supported by the manufacturers. The systems at Covert do not meet corporate cybersecurity standards and are operating with security exception to the Company's standards.

The cybersecurity tools (Power Water Cybersecurity Suite ("PWCS")) being utilized for the Covert control network device patching and antivirus protection require replacement to allow continued patching and protection with a new DCS version. The current version of PWCS is nearing the end of support and requires updating to allow support of the latest Ovation versions.

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1 The BOP control is achieved with the Ovation DCS. Its architecture is
2 comprised of controller and operator “drops” (processors and PCs) that provide
3 the control of the equipment with I/O modules. Some of these I/O modules are
4 in the same electrical cabinets that contain the “controller drops” (processors).
5 Other I/O is in “remote” electrical cabinets, away from the “controller drops.”
6 The existing plant control is comprised of many remote I/O cabinets throughout
7 the site. The communication modules to these cabinets have experienced
8 failures in the past that can trip the generating units offline. Power supplies in
9 the Ovation cabinets have reached the end of their recommended life and need
10 to be replaced. The architecture and components need to be upgraded and
11 replaced with the latest Ovation design.

12 The main controller drop that operates a large part of the BOP equipment
13 has had equipment and data link controls added to it over the years. It controls
14 equipment for all three (3) generating units. The controller drop needs to have
15 part of its I/O and logic split off to new controller drops. The partitioning of I/O
16 to other drops should allow the upgrade and maintenance procedures to occur
17 and reduce the need of a site outage to perform these activities. Risk to unit
18 trips should be reduced to individual generating units instead of all units on the
19 site. The concept approval document for this project is attached as Exhibit A-49
20 (RTB-10);

- 21 • Flame Detectors for Gas Turbine Wheel temperature Digital replacement
22 (\$273,000 total). The scope of this project is to replace the existing mechanical
23 flame detection system with a digital flame detection system. The existing
24 system is obsolete and has reliability issues that a new digital system would
25 resolve;
- 26 • Balance Of Plant Valves – Unit 1 (\$450,000). The scope of this project is the
27 repair and/or replacement of balance of plant valves. Project is to overhaul the
28 U1 HRS-PV105 and LPS-PV110 steam bypass valves. PV105 was last rebuilt
29 in 2017 and PV110 has never been overhauled. These valves are used for
30 startup, shutdown and unit trips to bypass steam to the condenser and
31 experience extreme service conditions that should be considered for overhaul
32 every 7 to 10 years. These projects should align with major outages to allow for
33 ample time to disassemble, inspect and repair. Overhauling the valves results in
34 reliable dependable service as these valves are critical to starting up and
35 shutting down the unit. They must also operate during trip conditions to prevent
36 an overpressure event and potential damage to other components;
- 37 • Balance Of Plant Valves – Unit 3 (\$450,000). The Scope of this project is to
38 overhaul the HRS-PV105 and LPS-PV110 steam bypass valves. PV105 was
39 last rebuilt in spring 2019 and PV110 has never been overhauled. These valves
40 are used for startup, shutdown, and unit trips to bypass steam to the condenser
41 and experience extreme service conditions that should be considered for
42 overhaul every 7 to 10 years;

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- 1 • Gas turbine generator and steam turbine generator auto voltage regulator –
2 Covert Units 1 and 3 (\$600,000 each). The current MEC5000 digital automatic
3 voltage regulators (“D-AVR”), which are over 20 years old, pose a substantial
4 risk of failure. Any failure in these D-AVRs renders both the gas turbine
5 generator (“GTG”) and steam turbine generator (“STG”) on the affected unit
6 unavailable, leading to extended outages and significant financial impacts. The
7 OEM has indicated a lead time of 18-24 months for new D-AVRs;
- 8 • AVR parts, further exacerbating the potential downtime. The Covert
9 Generating Station, operational since 2004, faces significant challenges with its
10 aging MEC5000 D-AVRs. These regulators, critical for controlling the
11 generators' response to load demand, are obsolete and no longer supported by
12 the OEM, Mitsubishi Electric (MELCO). This project proposes the replacement
13 of the MEC5000 D-AVRs with the advanced MEC700 AVR System for Units
14 1 and 3, to mitigate obsolescence risks and ensure reliable operation;
- 15 • Covert Units 1 through 3 MTX High Voltage Bushing – GSU (\$1,015,200
16 total). The 1MTX GSU transformer has over 20 years of service life and its
17 high voltage (HV) bushings are showing insulation deterioration that was
18 exposed through power factor testing prior to Consumers Energy ownership.
19 The GSU also is overdue for internal inspection with attention to mitigate risk
20 for its pacified oil that is still exhibiting corrosive potential properties. To
21 engineering's knowledge this unit has never been fully drained and undergone
22 internal inspection prior to or after the oil pacification work was performed
23 earlier in its life. The unit has oil that was pacified for corrosive Sulfur,
24 however Doble and other industry experts strongly recommend the pacified oil
25 be replaced as soon as possible since Sulfur corrosion leading to failure is still
26 probable due to remaining residuals in the pacified oil. It was noted in the root
27 cause analysis for the Zeeland Unit 2C GSU that corrosive sulfur had an impact
28 on its failure by reacting with conductors to create localized overheating. The
29 HV bushing replacement mitigates any potential for failure in service. The
30 bushing insulation properties continue to degrade over time as indicated
31 through recent power factor testing before Consumers Energy took over the site.
32 HV bushings power factor test results give the impression the bushings of
33 1MTX should have 5-10 years of life remaining before failure is realized,
34 however neither the rate of deterioration nor exact failure timeframe is
35 predictable. Due to lead times, planning for replacement is a more cost-effective
36 solution for customers than verifying they are failing during a future outage and
37 forcing extension until they can be replaced. A major outage for Covert will be
38 required to have enough time to execute the work, which will require at least
39 12 days based on similar scope at ZGS. Internal inspection is part of the
40 preventative maintenance plan and helps the Company determine the health of
41 the transformer, plan future outages as needed, and prevent forced outages,
42 thereby reducing potential ROR;
- 43 • Units 1, 2, and 3 NERC Relay Replacements and Test Switch Installation
44 (\$700,712). This project is needed to preclude unnecessary risk associated with

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possible relay failures as the existing relays are at the end of life. Running to failure is not an option for relay protection equipment because of the extremely high costs of equipment failures that could result if relay protection schemes failed to operate as designed. In late 2024, Covert experienced its first indication of a relay failure on Unit 3 and is operating at this time with no redundant protection in this specific zone. The failed relay is original to the plant and more relay failures can be expected as time goes on.

A failure of the remaining protection scheme in this zone would result in a forced outage, and it is expected that the turn-around time for sourcing, testing, installation, and commissioning of relays like this would take approximately two weeks if all went well. Relay manufacturers and Consumers Energy's High Voltage Distribution group use 25 years as recommended service life for these types of devices.

Each unit has multiple digital protection relays to ensure protection to the generation equipment (Generators/Exciters/Transformers) from local faults as well as to ensure protection from grid disturbances that could damage our valuable equipment. The original relays at Covert were not installed with the necessary test and cutout switches, which requires that the unit be offline for maintenance and replacement and creates greater potential for human performance errors that can jeopardize system reliability;

- LVDT Positioning Sensor – Units 1 and 3 Fuel Control Valves (\$507,000 each). The scope of these projects is to replace the Yokogawa 5516 mechanical type position sensors with LVDTs. The replacement to include the following devices, Main “A” pressure control fuel valve sensor, Main “B” pressure control fuel valve sensor, Main flow control fuel valve sensor, Pilot pressure control fuel valve sensor, and the pilot flow control fuel valve sensor and compressor bypass actuator. The benefits of this project include reduced maintenance, improved accuracy, and higher long-term reliability due to the removal of the mechanical linkages and converting to a non-contact mechanism.

The Covert Mitsubishi Power Gas turbines are equipped with Yokogawa 5516 mechanical linkage type position sensors. The Yokogawa position sensors are used to detect the position of the fuel control valves, bypass valve actuators, and the Inlet Guide Vanes. These Valves and their position are critical as they control turbine output which allows more load on the generator and meets load demand. The Yokogawa 5516 position sensors are obsolete, and Yokogawa has announced that the 5516 position sensors are no longer manufactured as of March 31, 2015, are no longer supported, and parts are no longer available. Mitsubishi Power recommends eliminating the Yokogawa mechanical linkage position sensors;

- Covert - HEPS/FAC/DAST Inspections (\$347,500). This project aims to bring the Covert site into compliance with existing corporate governance on

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1 G-A-313, G-A-314, and G-A-315 programs. Compliance with these programs
2 ensures the safe operation of the site and provides outage scheduling flexibility
3 by transitioning from a 12-month operating certificate to 2-year and 3-year
4 operating certificates. The project is essential to maintain the ability to
5 implement 2-year and 3-year operating certificates. Failure to perform the
6 required inspections would limit the unit to a 12-month operating certificate,
7 necessitating a full inspection before the unit can be certified to operate;

- 8 • Small Site Capital (\$285,000). This project supports capital expenditures for
9 replacement of small valves, instrumentation, tools, equipment, pumps, and
10 motors at Covert during the projected bridge period;
- 11 • Covert Base Outage Capital (\$360,000). Base outage capital covers the
12 replacement parts and issues found during turbine/generator inspections and the
13 major discovery issues found during annual unit outages; and
- 14 • Eighteen additional projects at Covert totaling \$2.185 million which support
15 safety, security, and reliability, with each project representing \$210,000 or less
16 in capital expenditures. These projects include Plant Fuel Gas Bypass System,
17 SP transformers, Gas Turbine - Unit 1 and 3 Evaporator Media, gas and steam
18 turbine excitation transformers, hydrogen new bulk system, Unit 2 LTSA extra
19 work, and air compressors.

20 **Karn Units 1 and 2**

21 **Q. Please explain the Company's projected capital investment for the 16-month**
22 **projected bridge period ending April 30, 2026 and the projected test year ending**
23 **April 30, 2027 for Karn Units 1 and 2.**

24 **A.** The Company does not plan to make any capital investments on Karn Units 1 and 2 in the
25 16-month projected bridge period ending April 30, 2026 or the projected test year ending
26 April 30, 2027, as shown on Exhibit A-12 (RTB-3), Schedule B-5.2, page 2, line 15,
27 columns (h) and (j), respectively, due to their retirement on May 31, 2023.

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Karn Units 3 and 4

Q. Please explain the Company's projected capital investment for the 16-month projected bridge period ending April 30, 2026 and the projected test year ending April 30, 2027, for Karn Units 3 and 4.

A. The Company plans to invest \$12.478 million in the projected bridge period and \$8.304 million in the projected test year, as shown on Exhibit A-12 (RTB-3), Schedule B-5.2, page 2, line 22, columns (h) and (j), respectively.

Q. What is the basis for the projected \$12.478million capital investment in the 16-month projected bridge period?

A. The projected \$12.478 million capital investment will fund numerous safety, regulatory compliance, reliability, and infrastructure projects at Karn Units 3 and 4. There are four projects which are greater than \$1 million, and these projects are presented on Exhibit A-12 (RTB-3), Schedule B-5.2, page 8, lines 17 through 20.

The basis for these projects is described below:

- Karn Unit 3 Combustion Air Heater replacement (\$2,700,000). This project spans the 16-month bridge period and the test year, and its basis is included in my discussion of the test year capital projects for Karn Units 3 and 4;
- Karn Unit 4 Combustion Air Heater replacement (\$3,000,000). This project spans the 16-month bridge period and the test year, and its basis is included in my discussion of the test year capital projects for Karn Units 3 and 4;
- Karn Units 3 and 4 Ductwork Expansion Joint Replacement – Induction Draft (“ID”) Fans to Stack (\$1,800,000). This project spans the 16-month bridge period and the test year, and its basis is included in my discussion of the test year capital projects for Karn Units 3 and 4;
- Karn Unit 4 Induced Draft (“ID”) Fan Inlet Damper Replacements (\$2,700,000). The scope of this project is to replace the ID fan inlet dampers. The Karn Unit 4 ID fan inlet dampers play a crucial role in regulating the fan load and maintaining a negative draft in the boiler, which is essential for safe and reliable operation. Over the last five years, the dampers have experienced multiple failures, leading to forced outages and significant de-rates, indicating

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1 the urgent need for replacement. The Karn Unit 4 ID Fan Inlet Damper
2 Replacement project is critical to ensuring reliable and efficient operation of the
3 unit. The current ID fan inlet dampers, which are essential for controlling the
4 boiler draft, are aging and have caused multiple forced outages and significant
5 capacity de-rates over the past five years. These failures have resulted in high
6 operational costs, inefficiencies, and risks of continued disruptions during peak
7 operational periods. Replacing the dampers is a proactive investment that will
8 eliminate these risks and provide long-term operational stability. The concept
9 approval document for this project is attached as Exhibit A-50 (RTB-11);

10 The following projects are less than \$1 million, but are important to reliability:

- 11 • Karn Unit 4 Vibration System Replacement (\$774,900). This project replaces
12 all Rockwell Automation XM Monitoring vibration modules that are currently
13 located in electrical junction boxes located around the Karn 4 turbine. The
14 existing junction boxes will be used as termination boxes and new cables run to
15 a central point on the Karn 4 turbine deck (turbine office at SW corner). A new
16 Ovation DCS cabinet with R-Line Machine Health Monitor “MHM” vibration
17 modules is to be installed in the turbine office area. This cabinet will contain
18 (6) 8-point MHM modules (total of 48 inputs) and two output
19 modules. Ovation OCC-100 redundant controllers will be used to integrate
20 with the existing Ovation DCS. The enclosure door will contain active buffered
21 output splitters to allow connection to the Consumers Energy turbine group’s
22 Turbo-Balancer. Redundant output modules will be utilized for proper
23 hardwired trip signals;

24 The existing Rockwell computer located in the Karn 3&4 DCS room will
25 be removed and all interfaces for the new system will be through the integrated
26 Ovation DCS operator and engineering drops. An Emerson Asset Management
27 System “AMS” Machine Works Server and Waveform Recorder Server
28 provides advanced condition monitoring and full vibration spectrum data for
29 historical playback of trip events and diagnostics of turbine issues. The sensors
30 and cables will also be replaced;

- 31 • BOP Capital tooling/valves/instrumentation (\$380,000). This project spans the
32 16-month bridge period and the test year, and its basis is included in my
33 discussion of the test year capital projects for Karn Units 3 and 4; and
- 34 • Ten additional projects at Karn Units 3 and 4 totaling \$1.123 million which
35 support safety, security, and reliability, with each project representing \$261,000
36 or less in capital expenditures. These projects include rewind of the Karn Unit 4
37 house service air compressor motor, replacement of the processors for the Karn
38 Units 3 and 4 main boiler feed pump relay control conversion to DCS, Karn
39 sync wire replacement, Karn Units 3 and 4 ID and forced draft (“FD”) fan
40 vibration systems, Karn Units 3 and 4 FD fan platforms, and replacement of
41 house service water (“HSW”) piping on Karn Units 3 and 4.

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1 **Q. What is the basis for the projected \$8.664 million capital investment in the projected**
2 **test year?**

3 A. The projected \$8.304 million capital investment in the projected test year will fund twelve
4 projects. Three of these projects are greater than \$1 million and are presented on Exhibit
5 A-12 (RTB-3), Schedule B-5.2, page 9, lines 15-17. The basis for these projects is
6 described below:

- 7 • Karn Units 3 & 4 Combustion Air Heater replacement (\$1,800,001 for Unit 3,
8 \$2,250,000 for Unit 4). The scope of these projects is to replace the combustion
9 air heaters. The D.E. Karn Generating Station, which utilizes natural gas and
10 oil, employs steam-to-air heat exchangers known as combustion air heaters to
11 preheat the ambient air entering the boiler. This preheating process is essential
12 for optimizing combustion efficiency. Specifically, Karn Units 3 and 4 rely
13 heavily on consistent air intake temperature to fine-tune the combustion air-fuel
14 mixture, crucial for maintaining emissions within acceptable opacity limits and
15 ensuring efficient heat rates as they do not have any other means of controlling
16 the output of particulate matter. The projected benefits include enhanced
17 reliability, improved efficiency, and ensured regulatory compliance, avoiding
18 projected capacity revenue losses of over \$23 million. This proactive approach
19 addresses the root cause of failures, providing a long-term solution for
20 operational efficiency and cost savings. The concept approval document for
21 these projects is attached as Exhibit A-51 (RTB-12); and
- 22 • Ductwork Expansion Joint Replacement –ID Fans to Stack (\$1,800,000). This
23 project will replace all expansion joints and entry doors between the ID Fans
24 and the stack. All expansion joints between the ID Fans and the Stack are
25 beyond their end of life and suspected to be severely degraded based upon the
26 condition of expansion joints found during the Karn Unit 3 Breeching project.
27 Failed expansion joints will need to be replaced to maintain environmental
28 compliance. This scope of work will make the ductwork air-tight again to
29 maintain environmental compliance.

30 The following projects are less than \$1 million, but are important to reliability:

- 31 • Karn Unit 3 Residual Oil Heater Overhaul (\$495,000). The scope of this project
32 is to install new tube bundles. The existing tube bundles have many leaks, and
33 the heaters are no longer functioning and are cut out of the system;
- 34 • Karn Unit 4 Ductwork Replace Insulation & Lagging - Boiler to Stack
35 (\$750,000). The scope of this project is to replace the lagging and insulation on
36 all the ductwork from the building out to the stack. The existing lagging and
37 insulation needs to be removed, the underlying steel fixed as necessary, and

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1 new insulation and lagging installed. The steel structure that the ductwork
2 lagging is attached to is severely corroded. This has allowed multiple random
3 failures of the lagging, resulting in a safety concern due to pieces of lagging
4 falling to the ground or becoming airborne during wind events;

- 5 • Karn Units 3 and 4 ID and forced draft (“FD”) Fan Vibration Systems
6 (\$266,400 per unit). The existing ID Fan Vibration System was originally used
7 for monitoring and alarming purposes only and was not designed to be a
8 vibration protection system. When a catastrophic ID Fan failure occurred in
9 2016, the vibration alarms were changed from only alarms to also tripping the
10 fan. With this change, the Company had several false positive trips from the
11 system resulting in unit trips. The original system currently provides an analog
12 signal into the DCS where the values are displayed and alarm messages are
13 generated, and the DCS stops the ID fan if the analog value goes above the trip
14 limit.

15 This project replaces the current system with Ovation Machinery Health
16 Monitor R-Line modules located in an Ovation remote I/O cabinet near the ID
17 Fans. The remote drop will utilize Ovation Remote Node Interface for
18 connection into the existing Ovation DCS. This will also provide vibration
19 monitoring and protection for the FD Fans. A total of 24 speed and vibration
20 sensors are included for the two ID and two FD fans and motors (3A and 3B ID
21 Fan and motor, and 3A and 3B FD Fan and motor). Active buffered output
22 splitters at the enclosure are also included to allow for supported vibration
23 monitoring with a 2140 portable monitor and use of the turbo balancer for fan
24 balancing. All waterfall and waveform plots of the vibrations are available for
25 display on the Ovation system. Full API-670 protection capability is provided
26 with seamless integration to the existing Emerson Ovation DCS;

- 27 • Capital tooling/valves/instrumentation (\$285,000). This project supports
28 capital expenditures for replacement of small valves, instrumentation, tools,
29 equipment, pumps, and motors at Karn Units 3 and 4 during the projected test
30 year; and

31
32 Three additional projects at Karn Units 3 and 4 totaling \$0.392 million which
33 support reliability, with each project representing \$180,001 or less in capital
34 expenditures. These projects include the Karn Units 3 and 4 FD fan outlet
35 dampers, HSW piping replacement, and tank farm PLC/DCS replacement.

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Zeeland Plant

Q. Please explain the Company's projected investment for the 16-month projected bridge period ending April 30, 2026 and projected test year ending April 30, 2027 for the Zeeland Plant.

A. The Company plans to invest \$67.275 million in the 16-month projected bridge period and \$40.023 million in the projected test year at the Zeeland Plant, as shown on Exhibit A-12 (RTB-3), Schedule B-5.2, page 2, line 29, columns (h) and (j), respectively. These capital expenditures will be facilitated, in part, by 35-day outages on Zeeland Units 1 and 2 in the spring 2025 as well as short outages of about 15 days in the spring and fall of the 16-month projected bridge period and the projected test year. The Company has an LTSA with GE that covers many reliability investments at the Zeeland Plant.

Q. What is the basis for the projected \$67.275 million capital investment in the 16-month projected bridge period?

A. The projected \$67.275 million capital investment will fund numerous safety, regulatory compliance, reliability, and infrastructure projects at the Zeeland Plant. There are five projects which are greater than \$1 million, and these projects are presented on Exhibit A-12 (RTB-3), Schedule B-5.2, page 8, lines 12 through 16. The basis for these projects is described below:

- LTSA/Phase I Gas Turbine Advanced gas path replacement and axial fuel staging (\$43,697,329). This project spans the projected bridge period and the projected test year, and its basis is included in my discussion of projected test year capital projects for the Zeeland Plant;
- Zeeland Phase II Turbine Replacements (\$10,174,501). This project spans the projected bridge period and the projected test year, and its basis is included in my discussion of projected test year capital projects for the Zeeland Plant;
- Zeeland Purchase of Site Spare GSU transformer (\$2,340,637). This project spans the projected bridge period and the projected test year, and its basis is

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1 included in my discussion of projected test year capital projects for the Zeeland
2 Plant;

- 3 • Unit 5 GSU Transformer Rewind (\$2,430,000). The scope of this project was
4 to remove the failed Zeeland Unit 5 GSU transformer, movement and
5 installation of the spare GSU transformer, and send out the failed Zeeland Unit
6 5 GSU transformer for overhaul which included milestone payments for the
7 overhaul. In addition, the scope reflected the monthly lease of a spare
8 transformer to provide continued operation of the unit for customers. Zeeland
9 Unit 5 was taken out of service on December 17, 2022 and was returned to
10 service on January 23, 2023 upon installation of the leased transformer which
11 was moved from Zeeland Unit 1. The project cost for 2025 reflects the return
12 of the leased transformer as well as the remaining lease payment; and
- 13 • Zeeland Plant LTSA supplementals not included in contract (\$4,703,401). This
14 project spans the projected bridge period and the projected test year, and its
15 basis is included in my discussion of projected test year capital projects for the
16 Zeeland Plant.

17 The following projects are less than \$1 million but are important to regulatory compliance
18 and reliability:

- 19 • GasTurbine inlet filters replacement (\$360,000). The scope of this project is to
20 replace canister filters. The filters are required to be replaced every five years
21 and must be accomplished during an outage. The purpose of the project is to
22 maintain the integrity of the filters to prevent material ingress to the turbines;
- 23 • Small Site Capital (\$380,000). This project spans the projected bridge period
24 and the projected test year, and its basis is included in my discussion of
25 projected test year capital projects for the Zeeland Plant;
- 26 • Asea Brown Boveri (“ABB”) DCS Evergreen (\$648,680). This project upgrades
27 the ZGS BOP DCS with the latest version available at the time of the project.
28 The system is currently running on a VMware virtualized system. The system
29 was installed in 2020. This Evergreen will only replace the existing ABB
30 Software, Operating Systems, and miscellaneous upgrades. The controller drops
31 and rack-mounted servers will not be replaced for this upgrade;
- 32 • ZGS – General Electric DCS Evergreen (\$839,665). The scope of this project is
33 to upgrade the Zeeland Plant Turbine Controls DCS with the latest version
34 available at the time of the project. The system is currently running on a VMware
35 virtualized system which was installed in 2020. This Evergreen will only replace
36 the existing GE Software, Operating Systems, and miscellaneous upgrades. This
37 project will allow the latest versions of control software and operating systems
38 to be used for reliable operation and control of the generating units. The latest
39 feature enhancements are also available for operation. This will also allow the
40 latest patches to be applied by the cyber security Emerson PWCS application.

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The DCS must be upgraded at a four-to-five-year upgrade cycle to maintain reliable control and recent operating systems and applications that are patchable. The vendor life cycle for DCS versions is generally five years. After five years they enter a retired state and are no longer patched. Microsoft Operating Systems are on a limited life basis, and they reach the end of “extended support” and no longer get security patches;

- Min Flow Bypass Valves Replacement (\$450,000). The scope of this project is to replace four minimum flow bypass valves. These valves are original to the plant and recent inspections have indicated nearly all the valve internals need replacement, which is also evident during operation with excessive leak-by. It was determined the most sensible approach is replacement due to the extent and cost of recommended repairs, and new valves will ensure continued reliability for 10+ years in the control of minimum flow for the FW pump system;
- Cooling Tower Transformer Replacement (\$225,000). The scope of this project is the replacement of the cooling tower transformer. Recent electrical testing indicated the transformer is failing. The Company determined that the most prudent option was replacement as compared to major repairs on a small transformer. Without this transformer, the cooling tower fans would not be operable, resulting in the Zeeland Phase 2 Units being shut down;
- Zeeland Plant Base Outage Capital (\$381,900). This project spans the projected bridge period and the projected test year, and its basis is included in my discussion of projected test year capital projects for the Zeeland Plant; and
- Seven additional projects at the Zeeland Plant totaling \$0.644 million supporting safety, reliability, regulatory compliance, infrastructure, and operations, with each project representing less than \$180,000 or less in expenditures. These projects include Phase II 2A and 2B battery monitoring system, GT1B excitation transformer failing components, and peaking plant Generation Peaker.

Q. What is the basis for the projected \$40.023 million capital investment in the projected test year?

A. The projected \$40.023 million capital investment in the projected test year will fund numerous safety, regulatory compliance, reliability, and infrastructure projects at the Zeeland Plant. There are four projects which are greater than \$1 million, and they are presented on Exhibit A-12 (RTB-3), Schedule B-5.2, page 9, lines 11-14. The basis for these projects is described below:

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- 1 • Zeeland Site Spare GSU Transformer (\$4,481,207). The scope of this project
2 is the procurement of a spare GSU transformer for the Zeeland site. The
3 Zeeland Plant consists of four gas turbine powered plants and one steam turbine
4 powered plant. The units transmit their power to the grid via GSU transformers.
5 If a GSU were to fail, then the associated turbine would not be able to transmit
6 power and would not be able to generate energy and capacity market value for
7 Consumers Energy and its customers. For the Zeeland combined cycle plant,
8 the combustion turbine requires the operation of the steam turbine, therefore the
9 loss of the steam turbine's GSU transformer would effectively limit operation
10 of two connected combustion turbine units. The lead time for a GSU
11 transformer is currently three to four years and spare units at other facilities are
12 not viable replacements due to compatibility and installation challenges. This
13 project would purchase a spare GSU transformer that is sized to be able to
14 replace any of the existing transformers on site and develop redundancy for any
15 minor power upgrades in the future;
- 16 • Phase II GT Advanced gas path replacement and axial fuel staging
17 (\$13,923,002). Zeeland Generating Station is a gas-powered combustion
18 turbine plant consisting of four gas turbines and one steam turbine. These
19 turbines are covered by a LTSA with General Electric to provide overhauls and
20 upkeep on the units to periodically restore them to like-new condition.
21 Periodically, the units are shut down for a major outage that is performed by
22 General Electric. Part of the major work executed during such outages is
23 replacement of the "hot", or combustion, parts as they degrade over their
24 32,000-hour design life. During these outages is the ideal time to incorporate
25 major work that will improve the performance and/or reliability of the unit. The
26 two gas turbines at Zeeland Phase 2 have Major Inspection outages in 2028.
27 This project is to implement upgraded replacement parts in both phase 2 gas
28 turbines. One such performance improvement (while maintaining the same
29 reliability) is called an Advanced Gas Path ("AGP"). The AGP package
30 provides significant output and efficiency (heat rate) improvements by
31 replacing the turbine and combustion parts with higher performing and more
32 technologically advanced parts. An additional improvement (while maintaining
33 the same reliability) is called Axial Fuel Staging ("AFS"). The AFS package
34 enables significant output turndown capability by replacing and adding
35 combustion hardware with more technologically advanced parts that enable
36 lower load operation while maintaining emissions compliance. This technology
37 is potentially key to the Zeeland Phase 2 plant's ability to be flexible in
38 supporting Consumers Energy's new energy portfolio, where a dramatic
39 increase in renewable energy will demand greater flexibility from the rest of the
40 generating assets in the portfolio. A more detailed analysis of this project is
41 presented in Exhibit A-44 (RTB-5);
- 42 • Zeeland Plant LTSA/Phase I Gas Turbine Advanced gas path replacement and
43 axial fuel staging (\$8,331,428). This is the capital portion for negotiated
44 services that cover the planned normal maintenance of each unit based on its
45 equivalent operating factor fired hours. The planned maintenance includes the

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1 following support services (OEM on-site/off-site technical support, engineering,
2 and labor). Typical activities include borescope inspections, capital repairs,
3 unit tuning, addressing service bulletin requirements, and on-site inspections.
4 Based on the OEM's operating and historical experience, if the Company
5 executes the normal planned maintenance and inspections according to the
6 recommended schedules, the Company will mitigate unexpected premature
7 failures of the equipment. Normal maintenance will ensure the Company
8 continues reliable operation of the units.

9 The Phase I Gas Turbine Advanced gas path replacement and axial fuel
10 staging project is being implemented in the Company's spring Phase 1 outage
11 beginning on April 21, 2025. A more detailed analysis of this project is
12 presented in Exhibit A-44 (RTB-5): Zeeland Phase 1 Gas Turbine upgrades;

- 13 • Phase II Turbine Replacements (\$10,174,501). The scope of this project
14 replaces the existing rotor with a new rotor, giving another 144,000 hours of
15 operation which would enable operation until the next rotor replacement out to
16 approximately the year 2045. Also included in this scope are new compressor
17 stator vanes due to the compressor being 20 years old; the best way to restore
18 the compressor to like-new condition is to replace the stationaries when the
19 blades will already be replaced. Lastly, the exhaust frame will be upgraded to
20 a robust exhaust frame due to reliability issues over the years, and the rotor
21 replacement being an appropriate time to replace the exhaust frame.

22 Several other critical projects which are less than \$1 million but are important to reliability
23 and infrastructure include:

- 24 • Zeeland Plant LTSA supplementals not included in contract (\$810,000). The
25 LTSA supplemental work is defined as the work that is not covered under
26 normal planned maintenance in the LTSA. Based on historical outage
27 experience there are typical discovery items found on this style of gas turbines
28 that are not part of the LTSA planned maintenance scope. Some of the typical
29 items that need to be addressed are labor and material to replace the following:
30 blading, combustion cans, ignitors, vanes/bushings, and any components on the
31 compressor end as the compressor is not covered under the LTSA;
- 32 • Small Site Capital (\$285,000). This project supports capital expenditures for
33 the replacement of small valves, instrumentation, tools, equipment, pumps, and
34 motors at Zeeland during the projected test year;
- 35 • Zeeland Plant Base Outage Capital (\$382,500). Base outage capital covers the
36 replacement parts and issues found during turbine/generator inspections and the
37 major discovery issues found during annual unit outages at Zeeland;
- 38 • Combined Cycle Units 3 and 4 Air Filter Replacement (\$648,000). The scope
39 of this project is to replace canister filters. The filters are required to be replaced

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every five years and must be accomplished during an outage. The purpose of the project is to maintain the integrity of the filters to prevent material ingress to the turbines; and

- Ten additional projects at the Zeeland Plant totaling \$0.987 million support reliability and operations, with each project representing \$240,000 or less in expenditures. These projects include Unit 1 and 2 battery monitoring system, 177, 277, 500 345kV breaker replacement, Phase 2 feed pump hydraulic coupling replacement, and Phase 1 Bentley Nevada vibration monitoring unit replacement.

Jackson Plant

Q. Please explain the Company's projected investment for the 16-month bridge period ending April 30, 2026 and test year ending April 30, 2027 for the Jackson Plant.

A. The Company plans to invest \$24.489 million in the 16-month projected bridge period and \$28.143 million in the projected test year at the Jackson Plant, as shown on Exhibit A-12 (RTB-3), Schedule B-5.2, page 2, line 36, columns (h) and (j), respectively. This will be facilitated by short outages in the spring and fall of 2025 and 2026. The Company has an LTSA with General Electric to cover many reliability issues at the Jackson Plant.

Q. What is the basis for the projected \$24.489 million capital investment in the 16-month projected bridge period?

A. The projected \$24.489 million capital investment in the 16-month projected bridge period will fund numerous safety, regulatory compliance, reliability, and infrastructure projects. There are four projects which are greater than \$1 million, and they are presented on Exhibit A-12 (RTB-3), Schedule B-5.2, page 8, lines 8-11. The basis for these projects is described below:

- Jackson Plant LTSA (\$16,200,153). This project spans the 16-month projected bridge period and the projected test year, and its basis is included in my discussion of projected test year capital projects for the Jackson Plant;
- Jackson Plant LTSA Extra Work (\$2,115,001). This project spans the 16-month projected bridge period and the projected test year, and its basis is

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1 included in my discussion of projected test year capital projects for the Jackson
2 Plant;

- 3 • GSU Transformer Site Spare (\$1,333,333). This project spans the 16-month
4 projected bridge period and the projected test year, and its basis is included in
5 my discussion of projected test year capital projects for the Jackson Plant; and
- 6 • LM6000 ESN 191-306 HP Turbine S2 Nozzle replacement (\$1,336,072).
7 During the bi-annual borescope inspection in April 2024 for the LM6000 gas
8 turbines at Jackson Generating Station, damage was identified at the High-
9 Pressure Turbine (“HPT”) Stage 2 Nozzle (“S2N”) Impingement Ring of
10 Engine Serial Number (“ESN”) 191-306. The gas turbine with ESN 191-306
11 was placed in an 'on watch' period per OEM guidance that results in a 250
12 running hour inspection frequency to determine if the damage progresses. There
13 is potential for the inspection frequency period to increase based on multiple
14 inspections. Ultimately the S2N assembly of the gas turbine that is damaged
15 needs to be replaced to restore the gas turbine to a serviceable condition.

16 Several other critical projects which are less than \$1 million but are important to reliability
17 and infrastructure include:

- 18 • JLM1-6 Variable Inlet Guide Vane (“VIGV”) Project (\$646,911). This project
19 spans the 16-month projected bridge period and the projected test year, and its
20 basis is included in my discussion of projected test year capital projects for the
21 Jackson Plant;
- 22 • Jackson Generating Station General Electric DCS Replacement (\$720,000).
23 This project replaces the GE DCS with the latest version available at the time
24 of the project. The system is currently running on a VMware virtualized
25 system. The system was installed in 2020. This Evergreen will only replace
26 the existing GE Software, Operating Systems, and miscellaneous upgrades.
27 The controller drops and rack-mounted servers will not be replaced for this
28 upgrade. (Standard practice is to replace virtualized system hardware every
29 eight years to reduce costs.) The DCS must be upgraded at a four-to-five-year
30 upgrade cycle to maintain reliable control and recent operating systems and
31 applications that are patchable. Vendor life cycle for DCS versions is generally
32 a five-year cycle. After five years they enter a retired state and are no longer
33 patched. Microsoft Operating Systems (O/S) are on a limited life basis, and they
34 reach the end of “extended support” and no longer get security patches.
35 Corporate policies require all systems to be patched regularly along with Anti-
36 Virus updates;
- 37 • LM6000 ESN 191-345 HP Turbine S1 Blade Replacement (\$763,781). There
38 are three LM6000 gas turbines (“GTs”) at JGS that are currently experiencing
39 burn through on their HPT Stage 1 Blades (“S1B”). Burn through represents
40 the loss of a protective thermal barrier coating on the blades and the beginning

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of wear into the blade surface and base metal. Once any individual blade of the HPT S1B set meets an unserviceable condition per the OEM specifications, the gas turbine will not be allowed to operate. The three LM6000 GTs that are experiencing this condition are indicated by their ESN, ESN 191-339, ESN 191-345, and ESN 191-307. There are bi-annual borescope inspections ("BSI") of all the JGS LM6000 GTs that monitor the GT condition. The BSI is the time where the HPT S1B condition is determined to be serviceable or unserviceable.

The three GTs of concern at this time are in a similar state of condition, but the timing and the sequence of an unserviceable condition for each will be based on the BSI. In general, the first GT in sequence that is labeled unserviceable will be pulled from service, sent for repair with a new set of HPT S1Bs, and returned to JGS. The set of HPT S1Bs pulled from the first GT will be overhauled and made available for the second GT that becomes unserviceable, and the set of HPT S1Bs pulled from the second GT will be overhauled and made available for the third GT that becomes unserviceable. The set of HPT S1Bs pulled from the third GT will be overhauled and returned to JGS to be used for future needs;

- Small Site Capital (\$380,000). This project spans the projected bridge period and the projected test year, and its basis is included in my discussion of projected test year capital projects for the Jackson Plant;
- Base Outage Capital (\$270,000). This project spans the 16-month projected bridge period and the projected test year, and its basis is included in my discussion of projected test year capital projects for the Jackson Plant; and
- Nine additional projects at the Jackson Plant totaling \$0.724 million, with each individual project representing \$225,000 or less in expenditures. These projects include Major Motor and Pump Replacements, Outdoor and roadway LED lighting replacement, Engine 191-306 Overhaul, Unit 7 Gas turbine rotor replacement, and LM6000 Beckwith Relay Replacement.

Q. What is the basis for the projected \$28.143 million capital investment in the projected test year?

A. The projected \$28.143 million capital investment in the projected test year will fund numerous safety, regulatory compliance, reliability, and infrastructure projects. There are four projects which are greater than \$1 million, and they are presented on Exhibit A-12 (RTB-3), Schedule B-5.2, page 9, lines 7-10. The basis for these projects are described below:

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- Jackson Plant LTSA (\$12,810,121). This is the capital portion for negotiated services that cover the planned normal maintenance of each unit based on its equivalent operating factor fired hours. The planned maintenance includes the following support services: OEM on-site/off-site technical support, engineering, and labor. Typical activities include borescope inspections, capital repairs, unit tuning, addressing service bulletin requirements, and on-site inspections. Based on the OEM's operating and historical experience, if the Company executes the normal planned maintenance and inspections according to the recommended schedules, the Company will mitigate unexpected pre-mature failures of the equipment. This will help maximize availability and, as a result, optimize customer value for the site. Normal maintenance will ensure the Company continues reliable operation of the units;

- Engine 191-306 Overhaul (\$6,130,000). The project involves the provision of a nozzle assembly from General Electric. General Electric will also provide three field service representatives to remove the gas turbine from its package, replace the HP Turbine Rotor assembly, reassemble the gas turbine, install it back in the package, perform alignment, and provide startup support. The work will take place at the Jackson facility.

During the bi-annual borescope inspection in April 2024 for the LM6000 gas turbines at Jackson Generating Station, damage was identified at the HPT S2N Impingement Ring of ESN 191-306. The gas turbine with ESN 191-306 was placed in an 'on watch' period per OEM guidance, resulting in a 250 running-hour inspection frequency to monitor the damage progression. Ultimately, the S2N assembly of the gas turbine needs to be replaced to restore the gas turbine to a serviceable condition;

- Unit 7 gas turbine rotor replacement (\$1,663,577). The scope of this project is to replace the Unit 7 Gas Turbine Rotor as it is essential to prevent high-probability failures, ensure continued operation, and avoid significant downtime. This investment will provide long-term reliability and efficiency for the plant's operations, ensuring optimal performance of the gas turbine. The Jackson Generating Station Unit 7 Gas Turbine Rotor Replacement project is a critical initiative aimed at ensuring the continued operation and efficiency of the GE 7EA gas turbine. The rotor for this turbine has a life limit of either 5,000 starts or 250,000 running hours. A new rotor will take approximately two years to be delivered after the order; and

- GSU Transformer Site Spare (\$2,333,334). This project provides Jackson with a reliable spare GSU to which it currently does not have access. The main transformers (GSUs) are a single point of failure in delivering power from the generators to the grid. For failure of one main transformer, lost generation would be 47 MW to 104 MW, depending on which generator(s) are connected. The lead time for a new transformer is three-to-four years, since every transformer of this size is custom built, and a large quantity of special raw materials is required. The Company's spare transformers located at Campbell,

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1 Karn, Lake winds, and Crosswinds do not have the correct voltage
2 (138kV-13.2kV-13.2kV) or correct winding configuration (WYE-DELTA) to
3 function at Jackson so they cannot be considered for use as spares. The concept
4 approval for this project is presented in Exhibit A-45 (RTB-6).

5 Several other critical projects which are less than \$1 million but are important to reliability
6 and infrastructure include:

- 7 • JLM1-6 VIGV Project (\$960,102). This project will install new VIGV systems
8 on six LM6000PC engines at the Jackson Plant. The seventh LM6000PC
9 engine has a partial installation already, and the project will complete the VIGV
10 system for this engine. For LM6000PC SPRINT gas turbines, which the
11 Jackson Plant has, the VIGV upgrade is expected to yield a significant fuel
12 efficiency improvement at part power. The average fuel efficiency
13 improvement at 70% of maximum power is greater than 2%. The VIGV also
14 helps minimize variable bypass valve ("VBV") flow and pressure levels,
15 thereby reducing associated flow noise. The VIGV system improves
16 performance for both simple cycle and heat-recovery cycles when operating at
17 less than full load;
- 18 • Jackson Plant LTSA Supplemental Work (\$315,000). The LTSA supplemental
19 work is defined as the work that is not covered under normal planned
20 maintenance in the LTSA. Based on historical outage experience there are
21 typical discovery items found on this style of gas turbines that are not part of
22 the LTSA planned maintenance scope. Some of the typical items that need to
23 be addressed are labor and material to replace the following: blading,
24 combustion cans, ignitors, vanes/bushings, and any components on the
25 compressor end as the compressor is not covered under the LTSA;
- 26 • Base Outage Capital (\$270,000). Base outage capital covers the replacement
27 parts and issues found during turbine/generator inspections and the major
28 discovery issues found during annual unit outages;
- 29 • 735 Breaker relay replacement (\$384,300). One of the General Electric
30 Multilin 735 relays that provides overcurrent protection to a large motor failed
31 in service. This model of relay is no longer available. There are five of these
32 relays at the Jackson plant. When another one fails, the motor will be forced out
33 of service for a long duration while relays of a different manufacturer are
34 installed. System protection recommends install of a SEL-551C and a BE1-851
35 as replacement;
- 36 • Steam turbine 9 blade replacement (\$260,837). Impact damage was identified
37 during the last major inspection of the unit in 2018. The first stage nozzle of the
38 Jackson Generating Station had a design flaw failure where the peened caulking
39 strips that hold the nozzle in its axial position liberated themselves from their
40 original positions in the caulk/peen groove because of the expansion and

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1 contraction in the area. The liberation of these pieces caused impact damage to
2 downstream components, most notably the rotor's blading. General Electric
3 recommended at that time that repairs be made during the next major inspection.
4 Blade replacement is needed for stages 1, 2, and 12. Other stages' blading may
5 require similar repairs. The rotor needs machining at radius leading to the stage
6 1 buckets due to imperfections from previous impact damage. Stage 10 blade
7 covers need to be removed and replace with "Foxhole" type covers due to
8 impact damage and erosion. The likelihood of the issues noted above achieving
9 further degradation is high. The severity of consequence of leaving the above-
10 mentioned damage as-is is high. The overall risk assessment is high (> 50%).
11 For the longevity of the unit these items need to be addressed during the
12 upcoming, routine overhaul;

- 13 • LM6000 ESN 191-307 HP Turbine S1 Blade Replacement (\$782,866). There
14 are three LM6000 GTs at JGS that are currently experiencing burn through on
15 their HPT S1B. Burn through represents the loss of a protective thermal barrier
16 coating on the blades and the beginning of wear into the blade surface and base
17 metal. Once any individual blade of the HPT S1B set meets an unserviceable
18 condition per the OEM specifications, the gas turbine will not be allowed to
19 operate. The three LM6000 GT's that are experiencing this condition are
20 indicated by their ESN, ESN 191-339, ESN 191-345, and ESN 191-307. There
21 are bi-annual BSI of all the JGS LM6000 GT's that monitor the GT condition.
22 The BSI is the time where the HPT S1B condition is determined to be
23 serviceable or unserviceable.

24 The three GTs of concern at this time are in a similar state of condition, but
25 the timing and the sequence of an unserviceable condition for each will be based
26 on the BSI. In general, the first GT in sequence that is labeled unserviceable
27 will be pulled from service, sent for repair with a new set of HPT S1B's, and
28 returned to JGS. The set of HPT S1B's pulled from the first GT will be
29 overhauled and made available for the second GT that becomes unserviceable,
30 and the set of HPT S1B's pulled from the second GT will be overhauled and
31 made available for the third GT that becomes unserviceable. The set of HPT
32 S1B's pulled from the third GT will be overhauled and returned to JGS to be
33 used for future needs;

- 34 • LM6000 HP Turbine S1 Blade Overhaul (\$817,859). There are three of six
35 LM6000 GT at JGS that are experiencing deterioration of their HPT S1B from
36 normal operation. The HPT S1Bs are experiencing burn through which is
37 described as the loss of the protective thermal barrier coating on the blades and
38 the beginning of wear into the blade surface and base metal. Once any
39 individual blade of the HPT S1B set meets an unserviceable condition per the
40 OEM specifications, the gas turbine will not be allowed to operate. The three
41 LM6000 GTs of concern will go through a sequence of replacing the HPT S1B,
42 once the third GT is complete there will be a set of HPT S1B that will need to
43 be overhauled for availability to the next LM6000 GT that requires the same

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blade set. This project is to capture the cost of the blade overhaul following the third LM6000 GT HPT S1B replacement;

- Small Site Capital (\$285,000). This project supports capital expenditures for the replacement of small valves, instrumentation, tools, equipment, pumps, and motors at Zeeland during the projected test year; and
- Ten additional projects at Jackson Plant totaling \$1.130 million, with each individual project representing \$225,000 or less in expenditures. These projects include 269 Breaker relay replacement, Site Control Room heating, ventilation, and cooling (“HVAC”) Replacement, 4160V Electrical Room HVAC Replacement, steam turbine 8&9 turning gear platforms, and Major Motor and Pump Replacement.

HYDRO UNITS

Q. Please explain the Company’s projected capital expenditures for the 16-month projected bridge period ending April 30, 2026 and the projected test year ending April 30, 2027 for the Hydro Units.

A. The Company is not presenting any capital investments during the 16-month bridge period or projected test year in the Hydro Units, as shown on Exhibit A-12 (RTB-3), Schedule B-5.2, page 3, line 50, columns (h) and (j), respectively. The Company is requesting continued deferral treatment as discussed in more detail in the direct testimony of Company witness Myers.

LPS

Q. Please explain the Company’s projected capital expenditures for the 16-month projected bridge period ending April 30, 2026 and the projected test year ending April 30, 2027 for the LPS.

A. The Company plans to invest \$15.225 million in the 16-month projected bridge period and \$13.282 million in the projected test year in the LPS, as shown on Exhibit A-12 (RTB-3), Schedule B-5.2, page 3, line 57, columns (h) and (j), respectively. These capital investments will be implemented during periodic outages in 2025 through 2027. It is

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important to note that none of these investments are associated with resolving the Toshiba defects. Those investments are being recorded to a regulatory asset pursuant to the MPSC's May 18, 2023 Order in Case No. U-21310.

Q. What is the basis for the projected \$15.225 million capital investment in the 16-month projected bridge period?

A. The projected \$15.225 million capital investment in the 16-month projected bridge period will fund numerous safety, regulatory compliance, reliability, and infrastructure projects. There are six projects which are greater than \$1 million, and they are presented on Exhibit A-12 (RTB-3), Schedule B-5.2, page 8, lines 21-26. The basis for those projects is described below:

- Ludington Units 1 through 6 DCS Control Relay Replacement (\$2,971,797). This project spans the 16-month projected bridge period and the projected test year, and its basis is included in my discussion of the projected test year capital projects for Ludington;
- LPS – Lower Penstock Expansion Joint (“LPEJ”) Chamber Waterstop replacement (\$2,009,804). The scope of this project is the replacement of the LPEJ waterstop and potentially dewatering the surrounding groundwater. The engineering study was performed in 2020 at a cost of \$0.404 million and project implementation began in 2021 and is planned to be completed in May 2025. In 2021, the engineering was completed, and the design was approved by FERC; and

The LPEJ Chambers enclose the penstock expansion joints in concrete chambers. The penstock expansion joints allow penstock expansion with seasonal temperature changes. The waterstop is a membrane intended to prevent groundwater from leaking into the LPEJ. Some joints have been leaking since shortly following plant construction. In February 2017, a depression was discovered upstream of Ludington Unit 3, which was caused by transport of soil into the chamber by inflowing groundwater. Historically, Consumers Energy sealed the leaks into the LPEJs using hydrophobic polyurethane grout. However, the waterstops are at the end of their expected life and grouting is no longer an effective solution. Failure to remedy the in leakage is a threat to generation because if the settlement of the chambers reaches a certain threshold, the generation unit(s) will remain in a forced outage until the LPEJ chamber(s) can be stabilized. The implementation of this project

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1 reduces current risk of a potential failure mode and supports Ludington unit
2 generation well into the relicensing period;

- 3 • Ludington 1 Pony Motor Overhaul (\$2,266,667). This project spans the
4 16-month projected bridge period and the projected test year, and its basis is
5 included in my discussion of the projected test year capital projects for
6 Ludington;
- 7 • Replace 480V Dike Load Center (“DLCs”) (\$1,287,697). This project spans
8 the 16-month projected bridge period and the projected test year, and its basis
9 is included in my discussion of the projected test year capital projects for
10 Ludington;
- 11 • Governor Replacement (\$2,026,247). This project spans the 16-month
12 projected bridge period and the projected test year, and its basis is included in
13 my discussion of the projected test year capital projects for Ludington; and
- 14 • Station Water Discharge Isolation Valve (\$1,161,403). The scope of work will
15 consist of the installation of a separate, parallel train oil water separator
16 (“OWS”) to that of the plant’s existing modification of existing support systems
17 (station sump, station sump pumps, & metering devices) to support new OWS,
18 and retrofit of existing OWS to improve oil separability. This will allow
19 temporary use of the modified original OWS while servicing the anticipated
20 new one so as to not impact unit availability. The Station Water Discharge
21 Header Isolation Valve and Oil Separator was previously approved into the
22 LTFP to assess the stations OWS due to off process conditions that had resulted
23 in reportable releases of oil into Lake Michigan. The main goal of this project
24 was to perform formal engineering evaluation of the plant’s existing OWS to
25 identify if it could likely serve the facility thought the current relicensing period
26 (2069) without major modification or replacement. In the intervening time since
27 that project was initiated, however, two separate reportable oil releases (as of
28 March 8, 2022) have occurred (Dec 2021 & Jan 2022). During evaluation of
29 these events, prior documentation & engineering analysis (1140-319-001 OIL
30 WATER SEPARATOR) of the existing OWS was located that indicates it has
31 suffered numerous failures in the past and is not effective at removing
32 contaminants from the influent to satisfy the facilities mandated NPDES
33 effluent requirements. As stipulated by the project charter, “Should the above
34 engineering evaluation conclude that significant changes are needed to the
35 separator or system configuration to meet current environmental and regulatory
36 standards a new project and LTFP funding request will be initiated to
37 implement these changes and utilize the engineering design basis established
38 within this project.” With the discovery of the aforementioned documentation
39 pertaining to the plant’s current OWS (1140-319-001), the justified conclusion
40 is that significant modifications to the system will be necessary to meet current
41 and future environmental standards. Therefore, this project will establish the
42 funding request to implement those changes to the facility and utilize the

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1 previously approved project to provide detailed engineering for such
2 modification.

3 The following projects are less than \$1 million but are important to regulatory compliance
4 and reliability:

- 5 • Station Power Transformer Life Cycle Management (\$442,156). This project
6 spans the 16-month projected bridge period and the projected test year, and its
7 basis is included in my discussion of the projected test year capital projects for
8 Ludington;
- 9 • Replace Barrier Net Panels (\$400,010). This project spans the 16-month
10 projected bridge period and the projected test year, and its basis is included in
11 my discussion of the projected test year capital projects for Ludington;
- 12 • LPS Intake Gate and Gate House Mechanical Replacement (\$425,376). This
13 project spans the 16-month projected bridge period and the projected test year,
14 and its basis is included in my discussion of the projected test year capital
15 projects for Ludington;
- 16 • Centralized Grease System Replacement (\$303,300). The current electro-
17 pneumatic grease system(s) that service the wicket gate bushings are
18 functioning past their service life and are of questionable reliability (original
19 plant equipment). Most of the components have worn seals, leak grease, and
20 have basic function. Replacement of end of service life components such as
21 pumps, distributing blocks, and solenoid valves. This project will modernize
22 the existing control system to a self-diagnostic PLC system;
- 23 • Ludington All Unit Critical Valve and Actuator Replacement (\$487,713). The
24 scope of this project is to replace valves, actuators, and associated equipment
25 critical to unit specific operation. There are also certain valves that provide
26 routine tagging points that provide worker protection. Many of these valves
27 have known issues such as damaged seals (leakage when the valve is closed),
28 leaking packing (cannot be tightened further), and severely corroded valve stem
29 extensions. Additionally, many of these valves are paired with pneumatic
30 actuators which have also been identified with operational issues. Most of the
31 handwheels are broken and do not provide a secondary means of operating the
32 valve if the pneumatic actuator were to fail. This could present a particularly
33 dangerous situation if a pipe were to fail. Additionally, damage to the actuator
34 linkages and slides have been noted in previous inspections. The linkage
35 damage has introduced play or slop into the mechanism which can be seen
36 during operation and will lead to eventual failure of the mechanism; and
- 37 • Fifteen additional projects at LPS totaling \$1.443 million, with each individual
38 project representing \$240,522 or less in expenditures. These projects include
39 Guide Bearing Oil Float Replacement, all unit flow transmitter replacement,

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ABB/Governor air compressors, Inlet 17 outlet corrugated pipe replacement, oil processing equipment replacement, and small tools, pumps, motors, valves, and instrumentation.

Q. What is the basis for the projected \$13.282 million capital investment in the projected test year?

A. The projected \$13.282 million capital investment in the projected test year will fund numerous safety, regulatory compliance, reliability, and infrastructure projects. There are four projects which are greater than \$1 million, and they are presented on Exhibit A-12 (RTB-3), Schedule B-5.2, page 9, lines 18 through 21. The basis for these projects is described below:

- DCS Control Relay Replacement (\$2,906,676). The scope of this project is to replace and eliminate worn and less reliable control relays with new electronic I/O modules and new relays where needed. The number of hardware control relays will be reduced due to the “control” being performed in logic instead of “hardwired” circuits. This will increase reliability and reduce outages and unit derates. Common control and monitoring of system equipment allows operation of the equipment from the HMI graphics and keeps the operator focused on one system instead of monitoring several systems from several areas of the control room.

The LPS units are controlled by using the original hardwired electromechanical relay control system to operate the units. A modern DCS system will provide the LPS units with improved diagnostic and troubleshooting capabilities. The DCS system will make it easier to automate any updates of equipment and systems that are integrated with the unit operation, and to implement, test, and verify changes to operating criteria. Furthermore, the modern DCS has the capability to perform these functions at a lower cost and requiring less time.

The existing relay control system is based on electromechanical devices that wear and become less reliable over time. The relay contacts wear, and increased resistance can cause intermittent failures. Troubleshooting these issues are difficult and time-consuming. The relay control system will not last until end-of-life of the units and need to be upgraded to a modern DCS control system. The Emerson Ovation DCS infrastructure was installed as part of the 2019-2021 Data Acquisition System (“DAS”), Annunciator, PLC, and Sequence of Events recorder replacement project. This provides a common historian, HMI graphics control, alarm management system and modern control system for reliable

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1 efficient unit operation. The DAS project provides the infrastructure to build
2 upon for full site/unit control at LPS;

- 3 • Ludington 1 Pony Motor Overhaul (\$2,800,000). The project will remove and
4 replace the existing pony motor rotors with new rotors that will provide another
5 50 years of service. It is assumed that the stators on both units can be reused,
6 and that the new rotor will be designed to work with the existing stator and
7 liquid rheostat. The new rotor will be redesigned to ensure that fatigue is no
8 longer an issue for the remaining life of the plant.

9 During the overhaul of Unit 1 (performed by Toshiba in 2018 and 2019), a
10 Non-Destructive Examination (“NDE”) test performed on the pony motor rotor
11 structure recorded linear indications, a.k.a. cracks, in presumed high stress
12 locations. Consumers Energy requested analysis by Toshiba at that time to
13 confirm the stress state of the rotor in operation, but Toshiba did not complete
14 it (note that while the Company requested this analysis from Toshiba, pony
15 motor replacement was not part of Toshiba’s scope for the overhaul). Prior to
16 re-assembly after the major overhaul work, the linear indications had been
17 repaired by Toshiba. The unit experienced problems with fastener failures after
18 being returned to service, and subsequent inspections identified that the linear
19 indications (cracks) returned, and that the indications continued to grow in
20 volume and size with use of the pony motor. Unit 1’s pony motor was
21 subsequently removed from service and the indications continue to be tracked
22 with regular inspections. Since the pony motor is no longer used to start the unit
23 in pump mode, the indications have not grown, nor have new indications been
24 noted. However, an analysis acquired by Toshiba at the Company’s request has
25 subsequently shown that the rotor material is beyond its fatigue life limit, which
26 explains the continued crack growth with Unit 1’s pony motor use. The major
27 risk is that if cracks begin to grow again, the whole unit must be taken off line
28 to protect the rest of the unit from failure. The pony motor will remain
29 unavailable to start the unit as a pump until the pony motor rotor is replaced.
30 And if the cracks begin to propagate again, the unit will be taken off line entirely
31 until the pony motor rotor can be replaced;

- 32 • Replace 480V DLCs (\$1,352,043). The scope of this project is the replacement
33 of the 20 480V DLCs over a six-year period that began in 2020 at a capital
34 expenditure amount of \$0.671 million. The DLCs are original plant equipment
35 and suffer from corrosion and deterioration. The primary purpose of the DLCs
36 is to distribute power to 193 dike drain pumps and 34 pumping relief wells
37 located around the reservoir. The purpose of the dike drain pumps is to keep
38 the upstream face of the dike in a drained condition and to protect the asphalt
39 liner from damage due to differential pressure. The purpose of the pumping
40 relief wells is to keep groundwater at pre-construction levels, thereby
41 minimizing the likelihood of a downstream slope failure. Replacement of the
42 DLCs over a six-year period will provide high electrical system reliability and
43 ensure FERC compliance; and

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- Governor Replacement (\$2,125,719). The scope of this project is to contract with a specialized vendor to inspect, repair as required, and modernize the unit governors. The LPS unit governors have not been overhauled in approximately 15 years and, as a result, show signs of significant wear.

The following projects are less than \$1 million but are important to regulatory compliance and reliability:

- LPS Commons Station Power Transformer (“SPT”) Life Cycle Management (\$643,137). The scope of this project is to procure and replace all six SPTs with new to suit size and configuration in current LPS footprint. The SPTs are original to the site and are in service outdoors on the LPS roof. The benefits of the project are restoration of system voltage to rated, increase site equipment life span, enablement of the ability to perform routine maintenance without risk of damage, and reduction in the probability of failure and the associated risk of not having a spare;
- Intake Gate and Gate House Mechanical Replacement (\$937,863). The LPS intake gates and associated hoist equipment are the primary form of mechanical protection for the LPS units. Their purpose is to isolate the stored energy from the reservoir’s water against each unit’s penstock when dewatering or during emergency conditions such as a penstock rupture or governor failure. Reliable operation of this system is critical to minimize damages from a unit run away condition or a penstock failure, acting as a last effort to control unit overspeed. The mechanical system of the intake gate hoist is all original (circa 1971) and recent OEM inspection revealed that its condition is poor and in need of refurbishment. Updates and repairs are required to support the current facility license extension of 2069. The electrical control system is well past its design service life. This outdated technology is obsolete, and certain critical components are no longer available for spare parts. Modern technology offers more reliable options that would give the system an additional 30 years of service. The head gate hoist is enclosed in a steel structure on top of the intake (head gate enclosure). The head gate hoist enclosures are original to the plant and have rusted out in many places. Significant corrosion has been noted on the steel frame, the connections, and the beams. These enclosures need to be replaced as they are beyond a repair option;
- Generator Potential Transformer and Enclosure Project (\$605,621). Each LPS Unit utilizes six Potential Transformers (“PT”) for Unit metering and regulating. A PT converts high primary voltage into a measurable low secondary voltage. The Metering PTs are utilized for indication of the Unit I/O and for the Disturbance Monitoring Equipment (“DME”). The Regulating PTs are utilized for Unit control and protection schemes. The current Unit metering and regulating PTs are plant original and have surpassed their life expectancy of 20-30 years. Occasionally, there have been unexplainable Unit trips due to a “PT Fail” alarm captured by the unit Exciters. This could be caused by a PT

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starting to fail. Most PT casings show their age in the form of cracks and separation of the molded casing. This can allow moisture ingress and internal insulating material loss. This can cause corrosion and overheating, ultimately leading to failure of the PT. The PTs are unlikely to last another 5-10 years and are suspected in the unexplained Unit trips. The PT enclosures are also original to the plant. There are three enclosures per unit, one for each phase (X,Y,Z). Each of the enclosures houses two drawers for the PTs, one regulating and one metering PT. The drawers have become difficult to open and close due to worn hardware. The enclosures also create a section of Isophase Phase Bus ("IPB") Duct for the IPB that connects the unit to the Starting Bus. This section of IPB Duct has been showing signs of damage due to eddy currents. This area is also a common Temporary Ground locations for workers protection during Unit and Starting Bus maintenance. The enclosure doors, where temporary grounds are installed, utilize an insert and bolt. These inserts increasingly become dislodged and fall into the Starting Bus. This causes emergent Working Clearance requirements to retrieve the inserts, so damage can't be caused by these inserts. Once an insert becomes dislodged, the insert hole becomes enlarged, and the insert can't be re- installed;

- Replace Barrier Net Panels (\$369,000). The panels are a regulatory required system to minimize fish entrainment. The panel replacements are primarily time based. LPS has extensive operating experience with these panels, which helps determine when a replacement is required; and
- Sixteen additional projects at Ludington totaling \$1.542 million, with each individual project representing \$227,778 or less in capital expenditures. These projects include Main Transformer Bank ("MTB") isophase cooling blower replacement, oil processing equipment replacement, guide bearing oil float replacement, unit thrust bearing strainer & differential pressure transmitter replacement, flow transmitter replacement, and small tools, pumps, motors, valves, and instrumentation.

ADMINISTRATIVE AND OTHER

Q. Please explain the Company's projected capital expenditures for the 16-month projected bridge period ending April 30, 2026 and the projected test year ending April 30, 2027 for Administrative and Other.

A. The Company plans to invest \$17.782 million in the 16-month projected bridge period and \$11.050 million in the projected test year in Administrative and Other, as shown on Exhibit A-12 (RTB-3), Schedule B-5.2, page 3, line 64, columns (h) and (j), respectively.

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1 **Q. What is the basis for the projected \$17.782 million capital investment in the 16-month**
2 **projected bridge period for Administrative and Other?**

3 A. The projected \$17.782 million capital investment in the 16-month projected bridge period
4 will fund environmental, reliability, and infrastructure projects. There are two projects
5 which are greater than \$1 million, and they are presented on Exhibit A-12 (RTB-3),
6 Schedule B-5.2, page 8, lines 27-28. The basis for those projects is described below:

- 7 • Wastewater Treatment System (\$12,400,004). This project spans the 16-month
8 projected bridge period and the projected test year, and its basis is included in
9 my discussion of the projected test year capital projects for Administrative and
10 other;
- 11 • Lakeshore Administration Building (\$3,702,428). The scope of this project is
12 to move the machine shop. The existing machine shop is located at the
13 Campbell site and with the closure of the Campbell units on May 31, 2025, the
14 Company will have to relocate the existing machine shop. Options for the
15 project include (1) doing nothing and going to third parties for parts which will
16 impact both cost and timing of delivery, (2) purchasing another machine shop,
17 (3) section off the training center at Campbell and move the machine shop to
18 that building, and (4) building a machine shop in a centralized location to better
19 service all generation sites.

20 The machine shop has proven its financial viability, routinely producing
21 annual revenues that are near or exceed annual operating costs. That trend is
22 expected to continue based on projections. The shop's ability to quickly turn
23 around projects and fabricate parts faster and at a lower cost than external
24 vendors has led to substantial savings, particularly in replacement power costs,
25 estimated at \$300k annually.

- 26 • In addition to the two projects above, there are eight additional projects totaling
27 \$1.679 million. These projects include generation cyber security, laptop and
28 capital business tool purchases for, Electric Supply, Environmental Services,
29 Lab Services, Business Planning and Administration, and Enterprise Project
30 Management.

31
32 **Q. What is the basis for the projected \$11.050 million capital investment in the projected**
33 **test year?**

34 A. The projected \$11.050 million capital investment in the projected test year will fund
35 regulatory compliance, reliability, and infrastructure projects. There is one project which

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is greater than \$1 million, and it is presented on Exhibit A-12 (RTB-3), Schedule B-5.2, page 9, line 22. The basis for this project is described below:

- Wastewater Treatment System (\$9,600,001). As discussed in more detail earlier in this direct testimony, the scope of this project is the treatment of wastewater that will continue to be generated at the Campbell site following cessation of coal generation in May 2025. The Company considered several options to address the ongoing leachate water, including transport for offsite disposal, offsite treatment, on site treatment and onsite disposal. Ultimately, on-site disposal via a deep injection well was selected and is currently being permitted by EGLE and EPA. The Company also submitted an NPDES permit application revision on November 7, 2024; and
- In addition to the project described above, there are eight additional projects totaling \$1.412 million. These projects include generation cyber security, laptop and capital business tool purchases for Electric Supply, Environmental Services, Lab Services, Business Planning and Administration, and Enterprise Project Management.

BATTERY ENERGY STORAGE SYSTEMS

Q. Please explain the Company's projected capital expenditures for the 16-month projected bridge period ending April 30, 2026 and the projected test year ending April 30, 2027 for BESS.

A. The Company plans to invest \$70.614 million in the 16-month projected bridge period and \$26.392 million in the projected test year in Company-owned battery resources, as shown on Exhibit A-12 (RTB-3), Schedule B-5.2, page 3, line 71, columns (h) and (j), respectively.

Q. What is the basis for the projected \$70.614 million capital investment in the 16-month projected bridge period?

A. The projected \$70.614 million capital investment in the 16-month projected bridge period will fund BESS. This entire investment amount is reflected in two separate projects, Iosco and Weadock, which are each greater than \$1 million and are presented on Exhibit A-12

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(RTB-3), Schedule B-5.2, page 8, lines 29 through 30. The basis for these projects is described in the direct testimony of Company witness Clark.

Q. What is the basis for the projected \$26.392 million capital investment in the projected test year?

A. The projected \$26.392 million capital investment in the projected test year will fund the BESS. This entire investment amount is reflected in two separate projects, Iosco and Weadock, which are each greater than \$1 million and are presented on Exhibit A-12 (RTB-3), Schedule B-5.2, page 9, lines 23 through 24. The basis for those projects is described in the direct testimony of Company witness Clark.

GENERATION CAPITAL EXPENDITURES—SUMMARY

Q. Are the Company's capital expenditures in power generation reasonable and prudent?

A. Yes. As discussed, the proposed capital expenditures are directly aligned with the Company's generation asset strategy and, as a result, will provide economic value for power supply customers in the energy and resource adequacy markets. Other capital expenditures in generation are related to regulatory and environmental compliance, and thus are not discretionary. Company witnesses Clark provides additional discussion in his direct testimony.

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SECTION IV

GENERATION O&M EXPENSE

Q. What are the major drivers in determining the O&M expense levels you are sponsoring in this proceeding?

A. The major drivers are identifying the funding needed to support the daily operation and maintenance of the Company's fleet of generating facilities and identifying the funding needed for certain internal organizations that support Generation Operations.

Q. For purposes of your direct testimony in this case, what does the Generation O&M cost represent?

A. In addition to the Company's generation fleet, I am sponsoring the O&M expenses for the Electric Supply Operations and PSCR organization, Electric Regulation and Strategy Implementation organization, Financial Planning organization, Renewable Energy Department, Contracts and Settlements organization, Generation Asset Management organization, Electric Sourcing and Resource Planning organization, Lean Organization, and Enterprise Project Management and Environmental Services organization.

Q. Please describe Exhibit A-43 (RTB-4), page 1, Generation Operation and Maintenance Expenses.

A. Exhibit A-43 (RTB-4), page 1, identifies the actual 2024 through 12-Months-Ending April 30, 2027 projected Generation O&M expenses. Specifically:

- Column (a) identifies each O&M expense category;
- Column (b) identifies the Actual 2024 Generation O&M expense as \$128,438,405;
- Column (c) identifies the 16-month Projected Bridge Period Generation O&M expense as \$150,445,403; and

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- Column (d) identifies the Projected Test Year Generation O&M expense as \$103,732,461.

HISTORICAL O&M EXPENSE

Q. How does Consumers Energy determine the level of Generation O&M spending?

A. Consumers Energy tracks the history and projects the future maintenance needs of each generating unit. Personnel at the plants provide information on maintenance for each site or specific units. Once costs to operate and comply with regulations are prioritized, the Asset Strategy and Generation Planning organizations evaluate the plans required to maintain and/or improve the condition of the plant – weighing the estimated benefit to the customer for each project. Using this combination of information, a preliminary plan is prepared and reviewed to ensure high-priority issues are addressed and adequate resources and funding are available. After all appropriate levels of management have reviewed and approved the maintenance plan, a schedule is created. The overall objective is the safe, reliable, and cost-effective generation of electricity.

Q. How are Generation O&M expenses categorized?

A. Generation O&M expenses are categorized into four primary components – “Base,” “Environmental Operations,” “Major Maintenance,” and “Retention and Separation.”

Q. What are Base O&M expenses?

A. Base O&M expenses comprises two categories – labor and non-labor. Labor is the primary component and typically has a predictable, stable rate of increase. Because most of the Company’s generating units have been in service for years, the Company has an excellent basis upon which to make accurate forecasts. Non-labor expenses also tend to increase at a predictable rate and include items required to operate the plants. These items include but are not limited to (1) fuel (diesel and gasoline) for equipment and vehicles, (2) material,

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(3) tools, (4) cleaning supplies, (5) facilities, (6) security, and (7) road and grounds maintenance.

Q. Please explain how the 2024 Actual O&M expenses were developed.

A. The 2024 Actual O&M expenses were taken from Consumers Energy's internal accounting records.

Q. Please explain how the 16-month projected bridge period and projected test year Base O&M expenses were determined.

A. Base O&M expenses for the 16-month projected bridge period ending April 30, 2026, and projected test year ending April 30, 2027 shown on Exhibit A-43 (RTB-4), page 1, line 1, columns (c) and (d), were determined by considering staffing levels and historical spending. Total O&M expense for the years 2024 through the projected test year demonstrates average annual decreases of approximately 9.0%. As discussed later in this direct testimony, this average annual decrease primarily reflects a change in the mix of the Company's owned generating assets including the movement of renewable energy resources to the Company's renewable energy plans. Exhibit A-43 (RTB-4), page 1, lines 3 and 4, identify Adjusted O&M expenses which are new or projected to change from past years' expense levels. These include items that are required by law to maintain environmental compliance, for the safety of employees, and to support the reliability of service to customers, specifically, Environmental Operations and Major Maintenance. Exhibit A-43 (RTB-4), page 1, line 5, identifies Adjusted O&M expenses which are related to Retention and Separation expenses associated with the Campbell site. These expenses were required for the safe and reliable operation of Karn Units 1 and 2 through their May 2023 retirement and Campbell Units 1, 2, and 3 through their May 2025 retirement.

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1 **Q. How do the historical and projected test year O&M expense amounts compare to**
2 **prior years?**

3 A. The 2024 historical O&M expense amount of \$128.438 million and the projected test year
4 O&M expense amount of \$103.732 million compare favorably to the actual O&M expense
5 amount for 2022; the 2022 generation O&M expense amount was \$150.031 million. The
6 projected test year O&M expense amount of \$103.732 million also compares favorably to
7 the actual O&M expense amount for 2023: the 2023 generation O&M expense amount was
8 \$118.848 million. As I previously stated, the O&M expense reductions reflect a mix of
9 generation asset changes, changes in major maintenance projects and expenses, cost
10 recovery realignment, and waste reduction measures.

11 **Q. Please explain Exhibit A-43 (RTB-4), page 2.**

12 A. Exhibit A-43 (RTB-4), page 2, presents the amounts of the projected O&M expenses that
13 were developed by applying either an inflation rate or contract rate to historical O&M
14 expense. Column (b) presents the historical O&M expense. Column (c) presents the
15 amount of the historical O&M amount to which an inflation rate or contract rate applies.
16 Columns (e) and (g) present the amounts to which an inflation rate or contract rate were
17 applied for each period, respectively. Columns (d), (f), and (h) present contract and
18 inflation increases for each respective period. Amounts that were projected using other
19 methods are included in column (i). Column (j) is the projected test year O&M and is the
20 sum of columns (b), (d), (f), (h), and (i).

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1 **Q. Please explain how the various inflation and contract rates were applied to Labor,**
2 **Material, Contractor, and Non-Labor Other O&M expense on Exhibit A-43 (RTB-4),**
3 **page 2.**

4 A. The historical labor on line 1, column (b) reflects a combination of both Operating
5 Maintenance and Construction (“OM&C”) and non-represented labor. Inflation rates of
6 2.1%, 2.4%, and 2.4% were applied to labor on line 1, material on line 2, contractor on
7 line 3, and non-labor other on line 4 to develop the annual increase amounts in columns (d),
8 (f), and (h).

9 **Q. Please discuss how the adjustments on Exhibit A-43 (RTB-4), page 2, column (i) were**
10 **determined.**

11 A. As previously discussed, the Company projects the future maintenance needs of each unit.
12 The test year projected O&M expense amount of \$103.732 million reflects that evaluation.
13 Within the test year projected amount of \$103.732 million, there are a number of
14 adjustments that result in a projected amount that differs from the amount that is calculated
15 based solely on inflation.

16 **Q. Please discuss the adjustments that are reflected in the test year projected amount of**
17 **\$103.732 million.**

18 A. As previously discussed Karn Units 1 and 2 retired on May 31, 2023 pursuant to a
19 Settlement Agreement in the Company’s 2018 IRP and the Settlement Agreement reached
20 in the 2021 IRP reflects the retirement of Campbell Units 1, 2, and 3 on May 31, 2025 and
21 the addition of Covert Units 1, 2 and 3 on June 1, 2023. In addition, several O&M groups
22 have changed O&M expenses, all of which I will discuss later in this direct testimony.

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1 **Q. Please discuss the O&M expense for Karn Units 1 and 2.**

2 A. The 2024 O&M expense for Karn reflects the fact that Karn Units 1 and 2 retired on
3 May 31, 2023, leaving only Karn Units 3 and 4 operational. The actual O&M expense for
4 the Karn site in 2024 was \$14.653 million versus the projected O&M for the test year at
5 \$14.829 million, a modest annual increase of approximately 0.51%. 2024 represented the
6 first full year of Karn operation without Karn Units 1 and 2. A complete discussion of the
7 test year major maintenance for Karn Units 3 and 4 is described later in this direct
8 testimony.

9 **Q. Please discuss the decrease in O&M expense for Campbell Units 1, 2, and 3.**

10 A. The projected test year O&M expense for Campbell reflects the fact that the Campbell units
11 will have ceased operation in May 2025, prior to the end of the bridge period. The
12 projected test year expense for Campbell is \$0.279 million, a \$41.061 million reduction
13 from the actual 2024 O&M expense of \$41.340 million. A complete discussion of the test
14 year major maintenance for Campbell Units 1, 2, and 3 is described later in this direct
15 testimony.

16 **Q. Please discuss the increase in total O&M expense for Covert Units 1, 2, and 3.**

17 A. The 2024 O&M expense for Covert reflects the Company's first full year of operation for
18 Covert after taking ownership of the plant on June 1, 2023. The actual O&M expense for
19 Covert Units 1, 2, and 3 in 2024 was \$13.508 million, and the projected O&M for the test
20 year is \$14.858 million, with the biggest increase reflected in major maintenance. The
21 2024 expense for major maintenance was \$6.553 million however it is projected to total
22 \$7.771 million in the test year. A complete discussion of the test year major maintenance

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1 for Covert is described later in this direct testimony. The environmental operations
2 expense and the base O&M are relatively flat from the historic year to the test year.

3 **Q. Please discuss the increase in total O&M expense for Ludington.**

4 A. The projected test year total O&M expense for Ludington reflects an increase of
5 \$2.263 million from the historical year to the test year. The projected test year total O&M
6 expense is \$11.661 million as compared to the historical year total O&M expense of
7 \$9.399 million. A large portion of the increase in the projected test year total O&M
8 expense is attributable to a \$1.394 million increase in major maintenance expense.
9 A complete discussion of the test year major maintenance for Ludington is described later
10 in this direct testimony. The balance of the increase is reflected in the base O&M expense
11 increase of \$0.860 million.

12 **Q. What is the basis for the increase in Ludington base O&M expense?**

13 A. The 2024 base O&M expense for Ludington totaled \$6.017 million and the projected test
14 year base O&M expense is \$6.877 million. There are three projects which primarily led to
15 that increase: (1) FERC Assessments, (2) license initiatives, and (3) fish protection.
16 The Company's 51% share of 2024 historical O&M expense for these projects was
17 \$1.272 million, \$1.872 million and \$2.135 million respectively, for a total of
18 \$5.280 million. The Company's share of the projected test year O&M expense for these
19 three projects is \$1.442 million, \$2.321 million, and \$2.361 million respectively, for a total
20 of \$6.123 million. The increase in projected expense for these three projects totals
21 \$0.843 million, consistent with the overall base O&M increase. Each of these projects are
22 required as part of the Company's FERC 50-year license and, as such, cannot be avoided.

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1 **Q. Please discuss the increase in O&M expense for the River Hydros.**

2 A. The projected test year total O&M expense for the River Hydros reflects an increase of
3 \$3.944 million from the historical year to the test year. The projected test year total O&M
4 expense is \$15.261 million as compared to the historical year total O&M expense of
5 \$11.317 million. Most of the increase in the projected test year total O&M expense is
6 attributable to a \$2.964 million increase in major maintenance expense. A more complete
7 discussion of the test year major maintenance for the River Hydros is described later in this
8 direct testimony. The balance of the increase is reflected in base O&M expense, an
9 increase of \$0.969 million from \$6.474 million in the historical year to \$7.444 million in
10 the projected test year.

11 **Q. Why should the Commission approve the Company's projected River Hydro O&M**
12 **expense?**

13 A. Regardless of the ultimate decision on whether to divest, relicense, or decommission the
14 respective River Hydro facilities, the O&M expenses requested in this case are needed to
15 appropriately operate and maintain those facilities to ensure they are safe and legally
16 compliant. The current timeline for divestiture would not likely result in a decision to
17 divest prior to the start of the test period on May 1, 2026. As such, the Company will need
18 to continue to maintain and operate the River Hydros through a portion of the test year, at
19 a minimum.

20 Further, should the divestiture not be achieved, the Company would need to
21 continue to operate and maintain the River Hydros until such time that a decision to
22 relicense or decommission the River Hydros is made. Even with a decision to
23 decommission the River Hydros, a process that would take more than 20 years, the

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1 Company would need to continue to operate and maintain the River Hydros until which
2 time they are decommissioned.

3 **Q. How does the Company propose to protect customers from excessive rates if the full**
4 **projected O&M expense for the test year is not required?**

5 A. The Company requests the Commission to approve a one-way tracker for the River Hydro
6 O&M expense. To the extent that future determinations obviate the need to reasonably and
7 prudently spend the Company's projected test year O&M expense for the River Hydros,
8 the Company proposes to refund the difference between the projected and actual amount
9 of O&M expense.

10 **Q. What does the Company mean with respect to one-way tracker?**

11 A. The Company only intends to refund the difference between the projected River Hydro
12 O&M expense and the actual River Hydro O&M expense in the event that actual expenses
13 are lower than projected, it does not propose to recover additional O&M expenses should
14 actual River Hydro O&M expense exceed the projected River Hydro O&M expense.

15 **Q. Please discuss the increase in total O&M expense for Administration and Generation**
16 **Commons.**

17 A. The projected increase in total O&M expense for Administration and Generation Commons
18 totals \$5.684 million and is due to a number of factors including the reorganization of the
19 Lean Organization, Enterprise Project Management tools and filling of vacancies, and
20 operations reliability spending. While much of this funding is initially budgeted for
21 Administration and Generation Commons, the actual O&M expense will ultimately be
22 assigned to the individual plants at which the work is performed.

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1 **Q. Are the changes discussed above the only reasons for the overall reduced O&M**
2 **expense?**

3 A. No. The Company has implemented other focused cost reductions that have directly
4 impacted both the projected bridge period and test year expense. These cost reductions
5 were primarily achieved through individual waste reduction projects.

6 **Q. Please discuss some examples of waste reduction projects.**

7 A. I will discuss two of the projects with the largest identified savings. The first project is the
8 “Nine Year Unit Mechanical Interval Inspection and Replacement” project at Ludington.
9 The Company evaluated the annual scope and was able to extend the inspections without
10 adding risk to the equipment. The Company’s projected test year spend for this major
11 maintenance project is \$358,000 as compared to the projected spend of \$570,000 in its
12 prior electric rate case, Case No. U-21585.

13 Another specific project is the “Capacity Factor Used For Water and Chemicals”
14 project at Covert. The Company identified a way to minimize the required water
15 requirements for the year through improved process and scheduling, resulting in a savings
16 of approximately \$300,000. While the total projected cost for this major maintenance
17 project is slightly higher than that same project presented in the prior electric rate case,
18 Case No. U-21585, the projected cost presented in this case is much lower than it would
19 have been otherwise.

20 **ENVIRONMENTAL OPERATIONS**

21 **Q. What are Environmental Operations expenses?**

22 A. Environmental Operations expenses consist of labor and materials supporting the
23 environmental operations of the Company’s AQCS. As Federal and State emissions

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standards require cleaner air, Consumers Energy has installed AQCS to comply with these regulations. Consumers Energy deployed its full suite of AQCS devices in 2016, with 2017 being the first calendar year of operation.

On a historical basis, the largest portion of this expense was incurred at the Company's Karn and Campbell coal units. However, with the 2023 retirement of Karn Units 1 and 2 and the May 31, 2025 retirement of Campbell Units 1, 2, and 3, the total projected environmental operations expense has dropped significantly as I will discuss later in this direct testimony.

Q. Please explain how the projected Environmental Operations expenses for the projected bridge period ending April 30, 2026 and test year ending April 30, 2027 were calculated.

A. Environmental Operations expenses have primarily been a combination of O&M costs related to the environmental equipment at the Karn and Campbell sites on a historical basis. The operations component was primarily calculated using labor costs for operations and environmental waste disposal. The maintenance component is based on a combination of historical and estimated planned maintenance costs on the specific components of environmental equipment. However, as reflected on Exhibit A-43 (RTB-4), page 1, line 3, columns (b) and (d), the walk from the 2024 historical expense of \$8.539 million to the projected test year expense of \$2.045 million reflects a cost reduction of \$6.439 million despite inflationary increases. This cost reduction is a direct reflection of the retirement of Campbell Units 1, 2, and 3 on May 31, 2025. Beyond May 2025, most of the environmental expense is associated with the continued operation of Karn Units 3 and 4 as well as

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1 projected environmental O&M expense at the gas-fired generating units, Ludington, and
2 the River Hydros.

3 **Q. What is the projected drop in Environmental Operations expense for the Campbell**
4 **site?**

5 A. The actual O&M expense for environmental operations for the Campbell site in 2024 was
6 \$6.513 million. The projected test year O&M expense for environmental operations for
7 the Campbell site is \$0, a reduction of \$6.513 million. As such, the balance of the
8 environmental operations O&M expense is basically flat from 2024 to the projected test
9 year, a very reasonable projection.

10 **MAJOR MAINTENANCE**

11 **Q. What are Major Maintenance expenses?**

12 A. Major Maintenance represents O&M projects that are based on asset condition or on
13 historic maintenance intervals over multiple years. To maintain and improve the
14 performance of the generating fleet, the Company performs Major Maintenance on a
15 regular basis. However, completion of Major Maintenance work can be influenced by,
16 among other things, actual operations of the generating units, availability of parts and labor,
17 and energy market conditions.

18 **Q. Please explain how the Major Maintenance O&M expenses for the 16-month**
19 **projected bridge period ending April 30, 2026 and test year ending April 30, 2027**
20 **were determined.**

21 A. Major Maintenance expenses are determined by tracking both the historical and future
22 maintenance needs for each site and unit, considering operation safety, unit reliability, and

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1 maximum customer value. Individual projects are calculated in a manner similar to capital
2 projects, as discussed earlier in this direct testimony.

3 **Q. Please identify the test year Major Maintenance O&M expenses.**

4 A. The Company projects that it will incur \$32.982 million in Major Maintenance O&M
5 expenses during the test year, as identified by Exhibit A-43 (RTB-4), page 1, line 4,
6 column (d). Test year Major Maintenance expense by generating unit is presented on
7 Exhibit A-43 (RTB-4), page 3, column (d).

8 **Q. Why is Consumers Energy spending \$32.982 million in total Major Maintenance**
9 **O&M expense during the projected test year ending April 30, 2027?**

10 A. The Company is spending the majority of its total Major Maintenance expense during the
11 test year to maintain reliability. Reliability related Major Maintenance O&M expenses,
12 made predominantly during scheduled outages, allow the plants to avoid equipment issues
13 that would lead to more frequent random outages, exposing customers to potentially more
14 expensive replacement energy and capacity at market prices. Minimizing forced outages
15 by maintaining equipment improves the likelihood the unit will be available when needed
16 and minimizing damage that could result in the event of a catastrophic failure.

17 **Q. Are Major Maintenance expenses relatively consistent from year to year?**

18 A. No. Although the Company attempts to plan for controlled and consistent levels of Major
19 Maintenance, because Major Maintenance outages occur relatively infrequently, for an
20 individual unit, it is very possible to have significant year-by-year variations in the number,
21 duration, and magnitude of the required Major Maintenance work. Other factors such as
22 unforeseen equipment failure, emerging industry initiatives, unit dispatch, expected power

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1 prices, unit performance, and simple timing variations can impact the cost and scheduling
2 of Major Maintenance.

3 **Q. Is it possible that changes to the Company's forecasted Major Maintenance plan**
4 **could occur?**

5 A. Yes. It is possible that the Company's forecasted Major Maintenance plan could change.
6 Equipment condition can change such that the timing of maintenance activities may need
7 to be accelerated or delayed. The Company attempts to make the best decision in balancing
8 the cost and risks associated with the operation of the equipment and attempts to minimize
9 the cost to customers. Factors such as weather, equipment and labor availability, energy
10 market conditions, and electrical system stability considerations can affect the actual
11 timing of an outage and maintenance spending.

12 **Q. Do Major Maintenance costs vary by individual generating unit(s)?**

13 A. Yes. While the Company's natural gas generating units are similar in age, they vary in
14 size, type, and design, so do the costs to maintain these units. As discussed earlier in this
15 direct testimony, the Company has LTSAs for its Covert, Jackson and Zeeland plants, with
16 two different OEMs. Because of these differences, the LTSA payments will vary
17 significantly from plant to plant as well as OEM to OEM.

18 **Q. Is it common for an electric utility to have different sizes, types, designs, and dispatch**
19 **of generating units in its generation portfolio?**

20 A. Yes. Consumers Energy is not unique in that its fleet contains units of different size, type,
21 and design.

22 **Q. What are the categories of Major Maintenance?**

23 A. Major Maintenance is broken into two categories—outage and non-outage.

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1 **Q. Please describe what is included in the outage major maintenance O&M expense.**

2 A. Outage major maintenance O&M expenses are those associated with major overhauls and
3 require that the generating unit be removed from service for HRSGs and/or turbine
4 inspections and maintenance. These outages are typically scheduled on a periodic basis
5 and are required by law, insurance providers, LTSA inspections based upon unit operating
6 hours, and/or industry standards to ensure operational safety and reliability. One example
7 of a major maintenance outage is the periodic disassembly and repair of turbine control
8 and stop valves. The valves control the amount of steam going to the turbine and are
9 needed to control the unit output. During an emergency situation, for example during unit
10 electrical trip, the valves must react very quickly to stop the steam going to the turbine to
11 prevent it from overspeeding. Overspeeding the turbine can result in severe mechanical
12 damage resulting in a very long duration outage to repair, further resulting in increased cost
13 to customers for market priced electricity during the outage. Periodic maintenance of
14 turbine valves is required for personnel and equipment safety. Maintaining the valves on
15 a periodic basis ensures that the clearances and internal components operate as designed
16 and can reliably stop the turbine quickly when needed to prevent turbine or generator
17 damage.

18 **Q. Please describe the work completed in a boiler inspection.**

19 A. Boiler inspections assess the fire (outside) and steam (inside) sides of boiler tubing for
20 weaknesses that will ultimately result in water/steam leaks. After the boiler has been
21 properly opened, ventilated, and cleaned, scaffolding is constructed inside the boiler to
22 provide access to the boiler tubes. Inspections are completed using a number of different
23 methods – visual, non-destructive, and destructive. Visual and non-destructive testing are

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1 the most common methods of inspection. Non-destructive testing incorporates the use of
2 ultrasonic, x-ray, magnetic particle, or like technologies to measure pipe wall thickness.
3 Boiler tubes that are in poor condition or exceed minimum wall thickness are repaired or
4 replaced. After all repairs are complete, boiler tubes are pressure tested. Each boiler is
5 inspected on a specific time schedule, with a one-, two-, or three-year maximum interval.
6 Internal components with known problems are inspected more frequently. External
7 inspections are performed daily by Generation Operations and annually by state inspectors.

8 **Q. Please describe the work completed in a turbine inspection.**

9 A. Turbine inspections consist of disassembling, inspecting, and cleaning the different
10 components of the turbine. During the inspection, worn or damaged parts are repaired or
11 replaced to specific tolerances. Because of the extreme conditions under which these units
12 operate, the demand for uninterrupted power, and dangers associated with operating these
13 large pieces of equipment, industry standards recommend that inspections be completed
14 every seven years.

15 **Q. Please define non-outage maintenance.**

16 A. Non-outage maintenance O&M costs typically do not require the generating unit be
17 removed from service, but they are still critical to the operation of the unit. An example of
18 non-outage maintenance is Mill/Pulverizer maintenance.

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Campbell Site Major Maintenance

Q. Please describe Campbell Site Major Maintenance expenses for the projected test year ending April 30, 2027.

A. As shown on Exhibit A-43 (RTB-4), page 3, lines 1 and 2, column (d), Campbell Units 1, 2, and 3 Major Maintenance expense is forecasted to be \$0.279 million in the projected test year ending April 30, 2027.

Q. Why is Consumers Energy projected to spend \$0.279 million in Major Maintenance on the Campbell units in the projected test year ending April 30, 2027?

A. Although the Campbell units will be retired on May 31, 2025, environmental regulations require the continued maintenance of the site landfill, water treatment plant, and site Rod Assisted Pipe system.

Karn Units 1 and 2 Major Maintenance

Q. Please describe Karn Units 1 and 2 Major Maintenance expenses for the projected test year ending April 30, 2027.

A. As shown on Exhibit A-43 (RTB-4), page 3, line 3, column (d), Karn Units 1 and 2 Major Maintenance expense is forecasted to be \$0.0 million in the projected test year ending April 30, 2027.

Covert Plant Major Maintenance

Q. Please describe the Covert Plant Major Maintenance expenses for the projected test year ending April 30, 2027.

A. As shown on Exhibit A-43 (RTB-4), page 3, line 8, column (d), the Covert Plant Major Maintenance expense is forecasted to be \$7.771 million in the projected test year ending April 30, 2027, and includes:

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- Covert Plant LTSA Major Maintenance (\$2,628,820). This is the major maintenance portion of the Mitsubishi negotiated services that cover the planned normal maintenance of each generating unit. The projected major maintenance expenses are based upon variable fees paid to Mitsubishi for maintenance services which are based on an effective fired hours basis pursuant to the LTSA. Unlike the General Electric LTSAs for the Jackson and Zeeland plants, there are no milestone payments associated with the fee structure for the Mitsubishi LTSA. Based on the OEM's operating and historical experience, if the Company executes the normal planned maintenance and inspections according to the recommended schedules, the Company will mitigate unexpected premature failures of the equipment. This will help maximize availability and, as a result, optimize customer value for the site. Normal maintenance will ensure the Company continues reliable operation of the units;
- Covert Plant LTSA extra work Major Maintenance (\$1,585,000). This is the major maintenance portion of the Mitsubishi negotiated services that are not covered in the planned normal maintenance of each generating unit. Based on historical outage experience, there are typical discovery items found on this style of gas turbines that are not part of the LTSA planned maintenance scope. Some of the typical items not covered under the LTSA that need to be addressed are labor and material to replace the following: blading, ammonia delivery system, SCR catalyst, turbine rotors, cooling towers, and turbine cooling air cooler;
- Covert Plant Capacity Factor Used For Water and Chemicals (\$1,300,000). This item provides for the city water used by the Covert Plant, and for the chemicals required to operate the water purification systems that are used to purify the makeup water prior to use;
- Reverse Osmosis System ("RO"), operation agreement (\$471,667). The scope of this project is to contract with a third party to operate and maintain the RO system;
- Covert Plant Base Outage Funding – Boiler plant equipment (\$425,000). Base outage capital covers the replacement parts and issues found during turbine/generator inspections and the major discovery issues found during annual unit outages;
- Covert Plant HEPS/FAC/DAST Inspections (\$712,500). This project will include the performance of regulatory required HEPS, DAST mid cycle inspection, and FAC inspection; and
- Six additional projects for Covert totaling \$648,269 in expenses, with each individual project representing \$238,702 or less in expenses. These projects include SCR cleaning annual maintenance, NERC relay and Direct Current ("DC") testing, ITC Transmission Co switchyard upgrades, gas turbine exhaust expansion joints repairs, and main inlet filters.

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Karn Units 3 and 4 Major Maintenance

Q. Please describe Karn Units 3 and 4 Major Maintenance expenses for the projected test year ending April 30, 2027.

A. As shown on Exhibit A-43 (RTB-4), page 3, line 4, column (d), Karn Units 3 and 4 Major Maintenance expense is forecasted to be \$1.824million in the projected test year ending April 30, 2027, and includes:

- Karn Units 3 and 4 Periodic Outage Major Maintenance (\$300,000). The scope of this project is to perform boiler maintenance activities during scheduled periodic outages during the projected test year. Expenses include planning, engineering services, materials, and overtime labor;
- Site Commons uninterruptible power supply (“UPS”) preventative maintenance (\$160,000). The scope of this project is to perform the required preventive maintenance on the UPS system;
- Karn Units 3 and 4 Opacity Improvements (\$150,000). Karn Units 3 and 4 are unable to run on oil and gas without having opacity excursions. This project will perform critical maintenance and repairs on the equipment related to these opacity issues; and
- Fourteen additional projects for Karn Units 3 and 4 totaling \$1.214 million in expenses, with each individual project representing \$140,000 or less in expenses. These projects include critical motor major maintenance, boiler required repairs, breaker maintenance, boiler pendant cleaning, and main & station power transformer testing.

Zeeland Plant Major Maintenance

Q. Please describe Zeeland Plant Major Maintenance expenses for the projected test year ending April 30, 2027.

A. As shown on Exhibit A-43 (RTB-4), page 3, line 6, column (d), Zeeland Plant Major Maintenance expense is forecasted to be \$5.419 million in the projected test year ending April 30, 2027, and includes:

- Zeeland Plant LTSA — Running Maintenance Contract (\$2,395,766). Consumers Energy has a long-term maintenance agreement with General Electric to perform the major maintenance and capital repairs necessary to

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maintain unit reliability. This item represents the O&M component of that service agreement;

- Zeeland Plant Capacity Factor Used for Water and Chemicals (\$1,293,615). This item provides for the city water used by the Zeeland Plant, and for the chemicals required to operate the water purification systems that are used to purify the makeup water prior to use;
- Base Outage — Boiler Plant Equipment (\$566,667). During planned and scheduled periodic outages, inspections and repairs are performed. Base boiler maintenance and outage is needed to complete condition assessment inspections of the boiler and major components, complete repairs on valves and large plant equipment, and complete repairs that are identified during shutdowns and condition assessments;
- Large Oil Filled Transformer maintenance (\$250,000). The scope of this project is to execute the 20-year major maintenance plan which includes (1) drain/process/reclaim oil, (2) perform internal inspections when drained, (3) perform planned repairs and evaluate as found conditions, and (4) perform electrical testing to internal circuits and supporting electrical components; and
- Seventeen additional projects totaling \$912,700 in expenses, with each individual project representing \$213,033 or less in expenses. These include drum level control valve overhaul, excitation and isolation transformer testing and maintenance, HEPS, FAC inspection, breaker maintenance, and NERC-required relay testing.

Jackson Plant Major Maintenance

Q. Please describe Jackson Plant Major Maintenance expenses for the projected test year ending April 30, 2027.

A. As shown on Exhibit A-43 (RTB-4), page 3, line 7, column (d), Jackson Plant Major Maintenance expense is forecasted to be \$4.112 million in the projected test year ending April 30, 2027. This forecasted expense consists of:

- Jackson Plant Capacity Factor Used for Water and Chemicals (\$2,722,395). This item provides for the city water used by the Jackson Plant and for the chemicals required to operate the water purification systems that are used to purify the makeup water prior to use. The projected expense is based upon historical monthly invoice values as well as consideration of the capital project previously discussed in this testimony for site generating water;

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- Jackson Plant Non-LTSA Turbine and jet engine repairs (\$400,000). The scope of this major maintenance is to perform jet engine repairs including bushing replacements every 12,000 hours;
- Jackson Plant LTSA — Running Maintenance Contract (\$500,000). Consumers Energy has a long-term maintenance agreement with General Electric to perform the major maintenance and capital repairs necessary to maintain unit reliability. This item represents the O&M component of that service agreement;
- Jackson Plant Base Outage - Boiler plant equipment (\$250,000). During planned and scheduled periodic outages, inspections and repairs are performed. Base boiler maintenance and outage is needed to complete condition assessment inspections of the boiler and major components, complete repairs on valves and large plant equipment, and complete repairs that are identified during shutdowns and condition assessments; and
- Five additional projects totaling \$240,081 with each individual project representing \$75,000 or less in expenses. These include pre-filter replacement, turbine building temperature control maintenance, chiller condenser cleaning, and NERC relay testing.

LPS Major Maintenance

Q. Please describe LPS Major Maintenance expenses for the projected test year ending April 30, 2027.

A. As shown on Exhibit A-43 (RTB-4), page 3, line 9, column (d), LPS Major Maintenance expense is forecasted to be \$4.708 million in the projected test year ending April 30, 2027, including:

- Fish Barrier Net - Installation, cleaning, and repairs and removal (\$2,182,503). This is a FERC regulatory requirement. The net is installed annually and maintained to meet FERC license requirements (and the requirements of a Settlement Agreement with federal and state natural resource agencies) and minimizes the impact of LPS on fish in Lake Michigan;
- Trench Feature Work (\$450,000). FERC Part 12 requires inspections to be performed on reservoirs every 5 years. This project includes performing a dam safety inspection on the upper reservoir clay liner, scour features, erosion gullies and tailrace. The annual reservoir inspection includes multi-beam sonar and side scan of the upper reservoir as well as a multi-beam sonar on the tailrace. The project is to perform engineering remediation on defects found and

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perform silica placement as necessary to remain compliant with FERC regulations;

- Scour Feature Repair Phase 2 and 3 (\$585,667). The project scope includes repairing the scour features on Units 1 and 6 by placing rip rap in the areas where rip rap has been displaced by the newer and more powerful pumping units. Construction would include filling the Unit 1 and Unit 6 scour feature areas with rip rap and fill voids with concrete, and placing 2" of concrete between the rip rap on the entire width of the rip rap apron to a length of about 400'. This would lock in the rip rap throughout the entire width of the 2' rip rap apron and prevent the rip rap apron from being scoured away.

The rip rap apron has experienced more scour due to the upgraded pumping units. The rip rap gets displaced, exposing the filter cloth underneath the rip rap and protecting the clay liner. Once the filter cloth is exposed, it historically has gotten ripped by the pumping units and exposed to the clay liner and potential scour. During the 2019 trench features inspection, the exposed fabric was ripped, exposing the clay liner in front of Unit 6 and allowing for the clay liner to be scoured away. The rip rap apron in front of Unit 1 has also experienced scour, which has moved riprap stone and exposed fabric on top of the clay liner. Since October 2019, the area of exposed clay in front of Unit 6 has grown from 6' diameter to 20' diameter and 1.5' of the 7-8' clay liner has scoured away.

The Company has committed to FERC that it would engineer a repair to address these recurring issues in 2020; engineering was complete in April 2020 and submitted to FERC for FERC approval. In February 2020, the Dam Safety Surveillance Monitoring Committee ("SMC") created threshold action levels for the scour features in concurrence with the Engineer of Record for the scour feature repair. At 0-1 ft of scour of the clay liner, no actions are necessary. At 1-2 ft of scour of the clay liner, the scour feature shall be inspected in the next May or October outage. At 2-4 ft of scour of the clay liner, an emergent repair is needed;

- Nine Year Unit Mechanical Interval Inspection and Replacement (\$358,000). The scope of this project is to perform replacement of common wear elements and consumable items associated with the pump/turbine units. This work will include the first nine-year maintenance interval for each of the six;
- Generator Circuit Breaker ("GCB") Pumping Pole Maintenance (\$200,000). This project will fund the work scope to annually rebuild the pump poles across the site to restore their operational life as per the GCB maintenance strategy. Expected duty cycles and wear rates observed will require the site to average one pump pole set per year with an associated cost around \$200k annually for the site to perform the required maintenance items to restore. This project is only for the pump poles and not the generating poles.

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The GCB contact assembly is configured with both main and arcing contacts. The arcing contacts are designed to be "sacrificial" to prolong the main contact life. The GCB cannot safely operate under a fault condition once the arcing contact life is expended at 25% life remaining, which will force the unit to be unavailable in pump mode operations until the proper maintenance is performed. The GCB pole maintenance must be addressed in a planned outage prior to reaching 25% calculated life remaining to mitigate costs of an individual outage just for GCB maintenance; and

- Twenty-three additional projects totaling \$932,059, with each individual project representing less than \$161,000 in expenses. These include Station Drainage Sump and oil/water separator cleaning, wicket gate repair, Depression Air Compressor Maintenance, periodic outage inspections and non-destructive examination, 480v Transfer bus clean and inspection, and Non-Destructive Inspection Of Insulated And Critical Piping Systems.

Hydro Major Maintenance

Q. Please describe Hydro Major Maintenance expenses for the projected test year ending April 30, 2027.

A. As shown on Exhibit A-43 (RTB-4), page 3, line 10, column (d), Hydro Major Maintenance expense is forecasted to be \$8.374 million in the projected test year ending April 30, 2027, and includes:

- Hydro License Initiatives (\$2,107,041). A FERC requirement, this item resulted from the relicensing of Au Sable, Manistee, and Muskegon River dams, with the main result being that the Company has annual license commitments. License commitments include some recreation, fish payments, and water quality such as upwelling systems licenses;
- Hydro annual FERC Dam Safety Requirements including Part 12 Inspections (\$1,441,220). The scope of this project is to perform the FERC-required dam safety inspections on an annual basis, and the FERC-required Part 12 inspections on each dam every five years. A similar level of expense, including modest escalation, is budgeted annually from 2026 through 2029;
- Foote Auxiliary Spillway Pilot Channel and Embankment Crest Grading Project (\$1,000,000). The scope of this project is to develop a design to raise or fill the existing auxiliary spillway pilot channel/ditch. In addition, repairs to the observed rutting and grading the right embankment crest, along with placing new fill as needed, will bring the embankment to a consistent elevation of 647.0 feet. This also includes the non-corewall section embankment widening, dependent on the results from the stability analyses.

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1 Raising the elevation of the auxiliary spillway pilot channel/ditch would
2 reduce the chance of the auxiliary spillway being activated. Repairing the
3 rutting and placing new fill on the embankments would increase the slope
4 stability factor of safety, thus reducing the chance of dam failure. This project
5 will meet FERC requirements and mitigate regulatory compliance risk.

6 The Part 12D Dam safety inspection by an independent consultant noted
7 several critical issues with the Foote Auxiliary Spillway. Flow within the
8 auxiliary spillway would initiate in the pilot channel/ditch at approximately
9 elevation 641 feet, which is 0.9 feet below the current Probable Maximum
10 Flood elevation of 641.9 feet. Additionally, rutting was observed on the right
11 embankment, and the elevation survey of the left embankment showed a
12 decrease of approximately 0.7 feet at Station 0+50 since the August 2013
13 survey. Elevations measured from Sta. 1+00 to Sta. 7+50 were below the
14 nominal embankment crest of elevation 647.0 feet, with a minimum of elevation
15 646.6 feet at Sta. 3+00.

16 Failure to comply with the Dam safety inspection recommendations could
17 result in regulatory agency action, including fines and potential loss of the
18 facility's operating license. For this project, the risk being mitigated is not the
19 risk of a probable maximum flood happening but the risk of FERC citing the
20 company for regulatory non-compliance and assessing fines accordingly. This
21 risk is significant given inspection result recommendations and operating
22 license commitments.

- 23 • Hardy Intake Tower Brick Repair (\$800,000). The scope of this project is to
24 replace all the deteriorated interior brick inside the intake tower for the full
25 height. The Hardy intake tower brickwork has been slowly deteriorating for the
26 last few years. The bricks are crumbling to the touch and there are areas with
27 significant delamination throughout the entire height of the walls (34ft). If the
28 deterioration becomes significant enough, it may impact the headgate hoists and
29 the head gates installation safety of the Operations staff;
- 30 • Tippy Spillway Chamber Inspections and Repairs (\$292,667). The project
31 scope includes performing spillway chamber inspections, engineering for
32 spillway chamber repairs and construction of repairs. The Tippy spillway
33 chambers are hollow chambers underneath the spillway. In the spillway
34 chambers, the concrete is deteriorated, rebar is exposed, and there is seepage
35 present;
- 36 • Hydro Concrete Repairs (\$243,100). The scope of this project is to make
37 necessary repairs to deteriorating concrete at all 13 River Hydro facilities. This
38 budgeted amount will allow for the performance of necessary repairs which are
39 identified after spring flows or general deterioration. The identification of large
40 concrete repairs will be considered in the annual budgeting process;

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- Five Channels Intake Deck Beam Bottom Side Repairs (\$240,000). The scope of this project is the completion of partial depth concrete repairs and cleaning and applying coatings to steel areas of degradation. This option removes the areas that have experienced degradation and thereby eliminates the ongoing debris loading hazard.

The Five Channels intake deck over the penstocks is a reinforced concrete slab, spanning upstream to downstream between intermediate concrete and steel support beams running (dam convention) left to right between penstock walls. The underside of the slab and support beams are exposed to the penstock environment. In 2018 a Condition Assessment was completed of the Five Channels Unit 1 and Unit 2 penstocks. From this assessment, it was identified that the reinforced concrete beam at the upper to lower deck transition in both Units 1 and 2 had experienced concrete spalling with reinforcement being exposed. Similarly, the steel beams supporting concrete haunches to the deck above had corrosion and spalling concrete. During the 2022 Headgate replacement project, these assessments were updated, revealing significant progression of deterioration on the Unit 2 concrete beam, with the lower layer of reinforcement completely exposed, and the second layer partially exposed. Unit 1 had similar progression, to a lesser extent. The problem associated with these observations is that the degraded/missing concrete and exposed reinforcement compromises the strength of the beam, and by extension the deck. The concrete spalling represents a debris hazard for concrete debris to the turbines below;

- Cooke Powerhouse Divider wall Pier (\$206,667). The scope of this project is to assess the condition of the divider pier between the powerhouse and the spillway and make repairs as needed to the diagonal cracking observed during the dive inspections and additional deterioration noted above water. The Part 12D independent consultant and third-party condition assessment consultant noted significant diagonal cracking in the divider pier between the powerhouse and the training wall (log chute) during the dive inspection. The underwater inspection indicated the diagonal crack is approximately 11-feet long and up to 3/8" wide. The diagonal cracking may be indicative of settlement. Other minor cracks, spalls, erosion, efflorescence, delamination, and vegetation growing in cracks are also located on the divider pier; and
- Thirty-one additional projects totaling \$2,043,000 with each individual project representing \$180,000 or less in expenses. These projects include Tippy and Cooke Log Chute Concrete Repairs, base outage funding, headgate evaluation and repairs, relief well piezometer cleaning, and condition/risk assessments.

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Admin and Other Major Maintenance

Q. Please describe Admin and Other Major Maintenance expenses for the projected test year ending April 30, 2027.

A. As shown on Exhibit A-43 (RTB-4), page 3, line 12, column (d), Admin and Other Major Maintenance expense is forecasted to be \$0.150 million in the projected test year ending April 30, 2027 and includes one project: Generation control systems cyber maintenance software support. Specifically, this project provides funding for software maintenance contracts from multiple vendor systems that are not part of the DCS control vendor service contracts.

Classic 7 Major Maintenance

Q. Please describe Classic 7 (Cobb, Weadock, and Whiting units) Major Maintenance expenses for the projected test year ending April 30, 2027.

A. As shown on Exhibit A-43 (RTB-4), page 3, line 5, column (d), Classic 7 Major Maintenance expense is forecasted to be \$0.218 million in the projected test year ending April 30, 2027.

Q. Why is Consumers Energy projecting to spend \$0.218 million in Major Maintenance on the Classic 7 units in the projected test year ending April 30, 2027?

A. Although the Classic 7 units were retired in 2016, environmental regulations require the continued maintenance of the on-site ash ponds, which includes Cobb landfill and ash pond O&M, Weadock landfill license and inspections, and Whiting ash pond post-closure care.

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KARN AND CAMPBELL RETENTION AND SEPARATION PLAN EXPENSE

Q. What are the projected costs for the Company's Karn and Campbell Retention and Separation plans?

A. As reflected on Exhibit A-43 (RTB-4), page 1, line 5, the Company incurred actual expense of \$8.626 million in 2024, and is projecting expense of \$5.182 million in the 16-month projected bridge period ending April 30, 2026. The actual 2024 expense of \$8.626 million is based upon expense of \$0.495 million for Karn and \$8.626 million for Campbell. The 16-month projected bridge period expense of \$5.182 million is entirely based upon expense of \$5.182 million for Campbell. There is no projected test year expense.

Q. Is the Company requesting O&M recovery of the \$5.182 million projected amount for the projected bridge period?

A. No. The Company is not requesting approval of this projected amount in Generation O&M expense. The Company received approval in Electric Rate Case No. U-20697, to defer the recovery of the Karn Retention and Separation O&M amounts for 2021 through 2023. The Company received approval to defer the recovery of the Campbell retention and separation amounts in the Settlement Agreement in its 2021 IRP. As such, the projected amounts for 2024 through the projected bridge period ending April 30, 2026 are not included in the Total O&M amounts on Exhibit A-43 (RTB-4), page 1, line 6, columns (b), (c) and (d). Company witness Daly supports regulatory asset treatment of these expenses in his direct testimony.

Q. Please describe the Karn retention and separation plan.

A. The Karn retention and separation plan was a people strategy that the Company had implemented to ensure that it could retain the necessary qualified employees to operate Karn Units 1 and 2 through their retirement date in May 2023, as well as during the cold

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1 and dark time period following retirement. The cold and dark condition refers to the period
2 following plant retirement and prior to plant decommissioning. During this period, limited
3 environmental remediation and perhaps partial demolition is performed. The facility may
4 be physically secured with fencing and other measures to prevent vandalism or theft so as
5 to limit liability risks. On June 7, 2019, the MPSC approved the Company's 2018 IRP
6 Settlement Agreement, which included the retirement of Karn Units 1 and 2 in May 2023.
7 The Company's IRP included detailed support of the Company's need to implement a
8 retention and separation plan to ensure that it could operate the plants safely and reliably
9 through their retirement date.

10 **Q. What is the purpose of the retention component of the Company's plan?**

11 A. The Company had a strong interest in keeping qualified employees working at Karn Units 1
12 and 2 through their retirement date to ensure safe and reliable operations. The retention
13 component allowed the Company to retain employees that may seek employment at other
14 Company locations or outside of the Company. The Company's ability to hire new
15 employees at Karn Units 1 and 2 became increasingly difficult given the short remaining
16 lifespan of the units and, to the extent that the Company had the ability to hire new
17 employees, the training time necessary for any new hires provided a significant challenge
18 to operating the units both safely and reliably. The retention component utilized the best
19 practices that the Company employed in retiring the Classic 7.

20 **Q. What is the purpose of the separation component of the Company's plan?**

21 A. Now that Karn Units 1 and 2 are retired, the Company is following the terms of the
22 collective bargaining agreement for OM&C employees represented by the Utility Workers
23 Union of America ("UWUA"), and the terms of the employee handbook policy and

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1 separation plan for non-represented exempt and non-exempt employees. The structure and
2 amount of the severance offers varies based on employee salary and classification due to
3 differences in the terms of the separation plan covering non-represented employees and the
4 bargaining agreement for UWUA-represented employees. In the event that exempt or
5 non-exempt employees cannot find placement within the Company within 60 miles of their
6 current location, they will be offered involuntary severance in accordance with the terms
7 of the Company's Salaried Separation Plan. The Company's Working Agreement with the
8 UWUA governs separation for OM&C employees who elect to leave the Company rather
9 than accept a new position as well as relocation expenses if they accept a position more
10 than 60 miles away from their current location.

11 **Q. What are the benefit types associated with the Karn retention and separation plan?**

12 A. The Karn retention and separation plan includes three benefit types: retention benefits,
13 severance benefits, and relocation and moving costs.

14 **Q. Please describe the retention benefits associated with the Karn retention and**
15 **separation plan.**

16 A. The retention benefits associated with the Karn retention and separation plan include three
17 payment components: a signing incentive, annual incentives, and a final retention
18 incentive.

19 Employees received a signing incentive equal to 15% of their base pay if they
20 signed a retention agreement in October 2019. By signing the retention agreement, the
21 employee agreed to forfeit their transfer rights under the current working agreement (for
22 union employees) or under Company policy (for exempt and non-exempt employees). The
23 employee had to stay at Karn until October 31, 2020 to receive the payment; if the

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1 employee stayed until that date, the incentive was paid out to the employee within 30 days.

2 If the employee separated from the Company before October 31, 2020, the employee
3 forfeited the signing incentive.

4 Employees received an annual incentive which graduated from 20% to 30% of their
5 base pay for service each November in years 2019, 2020, and 2021, for staying at Karn and
6 rendering service for the next 12 months. The employee had to stay at Karn until
7 October 31 of the following year to receive the payment; if the employee stayed until that
8 date, the incentive was paid out to the employee within 30 days. If the employee separated
9 from the Company before October 31 of the next year, the employee forfeited the annual
10 incentive. Eligible employees received their first annual incentive payment in November
11 2020, a second payment in November 2021, and a third payment in November 2022.

12 Employees received their final retention incentive equal to 60% of their base pay
13 following plant retirement if the employee was still at Karn. The payment was intended to
14 incentivize employees to stay until the plant went cold and dark and compensate employees
15 for the service they rendered for the eight months (November 2022 through June 2023)
16 prior to the payment.

17 **Q. Please describe the severance benefits associated with the Karn retention and**
18 **separation plan.**

19 **A.** The severance benefits associated with the Karn retention and separation plan includes
20 initial recognition of a severance benefit to be paid, recognition of additional severance
21 earned (one week of pay per year of service), and recognition of the accretion of a final
22 severance benefit.

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1 **Q. Why did the Company anticipate the need to make severance payments associated**
2 **with the retirement of Karn Units 1 and 2?**

3 A. The Company is proud of the fact that following the retirement of the Classic 7 in 2016,
4 all Company employees that desired to continue employment with the Company were able
5 to do so. However, the Company is also aware of the fact that it has fewer Company
6 locations (11 within 60 miles of the Karn site) to which employees could relocate, than it
7 did in 2016. As such, the Company anticipated the need to make severance payments to
8 those employees that could not find placement. As I previously stated, the Company is
9 following the terms of the collective bargaining agreement for OM&C employees
10 represented by the UWUA, and the terms of the employee handbook policy and separation
11 plan for non-represented exempt and non-exempt employees.

12 **Q. Please explain the relevant details of the collective bargaining agreement for OM&C**
13 **employees.**

14 A. The collective bargaining agreement for OM&C employees, in Article VII, Section 17, and
15 the Generation Operations Coal Closing Agreement provide that employees will be placed
16 in either a corresponding position, or if none exists, in a vacant position he/she is qualified
17 to perform within 60 miles of his/her current headquarters. Per Article XVII of the
18 collective bargaining agreement, employees who are released due to lack of work, and are
19 not placed as described above, are provided a separation allowance consisting of straight
20 time pay for five regular workdays for each year of continuous service with the
21 Company. Due to the lack of Company locations within 60 miles of Karn Units 1 and 2,
22 as described above, it was anticipated that some employees would be eligible for a
23 separation allowance.

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1 **Q. Please describe the Campbell retention plan.**

2 A. The Campbell retention plan is a people strategy that the Company proposed in its 2021
3 IRP. As previously discussed, the Company's 2021 IRP PCA reflects the retirement of
4 Campbell Units 1, 2, and 3 on May 31, 2025. This retention plan was proposed in order to
5 retain employees through the closure of the three Campbell units. This strategy is
6 necessary to ensure that the Company can operate the Campbell units safely and reliably
7 through their retirement date. This incentive program is the same program that is currently
8 in place for employees at the Karn site.

9 **Q. What is the purpose of the retention component of the Company's plan?**

10 A. For similar reasons described in the Karn retention plan, the Company had a strong interest
11 in keeping qualified employees working at the Campbell site through their retirement date
12 to ensure safe and reliable operations. The retention component will allow the Company
13 to retain employees that may seek employment at other Company locations or outside of
14 the Company. Similar to the situation at the Karn site, it was increasingly difficult to hire
15 new employees at the Campbell site given the short remaining lifespan of the units and, to
16 the extent that the Company has the ability to hire new employees, the training time
17 necessary for any new hires provided a significant challenge to operating the three units
18 both safely and reliably.

19 **Q. What is the purpose of the separation component of the Company's plan?**

20 A. After the Campbell units are retired, the Company is following the terms of the collective
21 bargaining agreement for OM&C employees represented by the UWUA, and the terms of
22 the employee handbook policy and separation plan for non-represented exempt and
23 non-exempt employees. The structure and amount of the severance offers will vary

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1 based on employee salary and classification due to differences in the terms of the
2 separation plan covering non-represented employees and the bargaining agreement
3 for UWUA-represented employees. In the event that exempt or non-exempt employees
4 cannot find placement within the Company within 60 miles from their current location,
5 they will be offered involuntary severance in accordance with the terms of the Company's
6 Salaried Separation Plan. The Company's Working Agreement with the UWUA governs
7 separation for OM&C employees who elect to leave the Company rather than accept a new
8 position as well as relocation expenses if they accept a position more than 60 miles away
9 from their current location.

10 **Q. What are the benefit types associated with the Campbell retention plan?**

11 A. Similar to the Karn retention and separation plan, the Campbell retention plan includes
12 three benefit types: retention benefits, severance benefits, and relocation and moving costs.

13 **Q. Please describe the retention benefits associated with the Campbell retention plan.**

14 A. The retention benefits associated with the Campbell retention plan include three payment
15 components: a signing incentive, periodic incentives, and a final retention incentive. The
16 timeline for retention benefits reflects approval of the Settlement Agreement in the
17 Company's 2021 IRP in June 2022.

18 Employees received a signing incentive equal to 15% of their base pay if they
19 signed a retention agreement in July 2022. By signing the retention agreement, the
20 employee agreed to forfeit their transfer rights under the current working agreement (for
21 union employees) or under Company policy (for exempt and non-exempt employees). The
22 employee had to stay at Campbell until October 31, 2022 to receive the payment; if the
23 employee stayed until that date, the incentive was paid out to the employee within 30 days.

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1 If the employee separated from the Company before October 31, 2022, the employee
2 forfeited the signing incentive.

3 Employees received a periodic incentive which graduates from 20% to 30% of their
4 base pay for service each November in years 2022, 2023, and 2024, for staying at Campbell
5 and rendering service for a certain period. Specifically, for service provided July 2022
6 through October 2022, employees received 20% of their base pay. For service provided
7 November 2022 through October 2023, employees received 25% of their base pay. For
8 service provided November 2023 through October 2024, employees received 30% of their
9 base pay. The employee must stay at Campbell until October 31 of the given year to receive
10 the payment; if the employee stays until that date, the incentive was/will be paid out to the
11 employee within 30 days. If the employee separates from the Company before October 31
12 of the given year, the employee forfeits the annual incentive.

13 Employees receive a final retention incentive equal to 60% of their base pay on or
14 about October 31, 2025, if the employee is still at Campbell. The payment is intended to
15 incentivize employees to stay until the plant goes cold and dark and compensate employees
16 for the service they rendered for the 12 months prior to the payment.

17 **Q. Please describe the severance benefits associated with the Campbell retention plan.**

18 A. The severance benefits associated with the Campbell retention plan include initial
19 recognition of a severance benefit to be paid, recognition of additional severance earned
20 (one week of pay per year of service), and recognition of the accretion of a final severance
21 benefit.

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1 **Q. Why does the Company anticipate the need to make severance payments associated**
2 **with the retirement of Campbell Units 1, 2, and 3?**

3 A. The Company is proud of the fact that following the retirement of the Classic 7 in 2016,
4 all Company employees who desired to continue employment with the Company were able
5 to do so. However, the Company is also aware of the fact that it has fewer Company
6 locations (seven within 60 miles of the Campbell site) to which employees can relocate,
7 than it did in 2016. In addition, the Company also retired two of the Karn generating units
8 in 2023, thereby further reducing the available positions. As such, the Company has
9 anticipated the need to make severance payments to those employees who cannot find
10 placement. As I previously stated, the Company is following the terms of the collective
11 bargaining agreement for OM&C employees represented by the UWUA, and the terms of
12 the employee handbook policy and separation plan for non-represented exempt and
13 non-exempt employees, as previously discussed for the Karn retention and separation plan.

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

15 A. Yes, it does.

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 generation and distribution of)
 electricity and for other relief.)
 _____)

Case No. U-21870

REVISED REBUTTAL TESTIMONY

OF

RICHARD T. BLUMENSTOCK

ON BEHALF OF

CONSUMERS ENERGY COMPANY

October 2025

RICHARD T. BLUMENSTOCK
U-21870 REVISED REBUTTAL TESTIMONY

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

2 A. My name is Richard T. Blumenstock, and my business address is One Energy Plaza,
3 Jackson, Michigan 49201.

4 **Q. Are you the same Richard T. Blumenstock who previously submitted direct testimony**
5 **in this proceeding on behalf of Consumers Energy Company (“Consumers Energy”**
6 **or the “Company”)?**

7 A. Yes.

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

9 A. The purpose of my rebuttal testimony is to rebut the direct testimony of Michigan Public
10 Service Commission (“MPSC” or the “Commission”) Staff (“Staff”) witness Laura Maio;
11 Attorney General witness Sebastian Coppola; Michigan Environmental Council and
12 Citizens Utility Board of Michigan (collectively “MNSC”) witness Tyler Comings; and
13 Association for Businesses Advocating Tariff Equity (“ABATE”) witness Jessica A. York.
14 In addition, I will provide rebuttal to MNSC witness Richard J. Bunch; witness William D.
15 Kenworthy on behalf of the Ecology Center, the Environmental Law & Policy Center, the
16 Union of Concerned Scientists, and Vote Solar (collectively the “Clean Energy
17 Organizations” or “CEO”), and Great Lakes Renewable Energy Association (“GLREA”)
18 witness Richard Boehnke.

19 Specifically, I will provide rebuttal to address Ms. Maio’s proposed adjustments to
20 the bridge period capital projects over \$1 million, the class estimate reduction in generation
21 capital expenditures for the projected test year, and reduction to the test year operation and
22 maintenance (“O&M”) expense. I will provide rebuttal to Ms. York’s proposed reductions
23 in generation capital expenditures for long term service agreement (“LTSA”) extra work

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at the Covert, Jackson, and Zeeland Generating Stations and I will provide rebuttal to Mr. Comings' proposed reductions to two capital projects at the Jackson Generating Station, some modeling recommendations, and his analysis of the Jackson Generating Station. I will also provide rebuttal to Mr. Coppola's extensive list of unsupported proposed capital expenditure disallowances at the Covert, Jackson, and Zeeland Generating Stations as well as a disallowance of the capital expenditures for an environmental project at the J.H. Campbell ("Campbell") site. Finally, I will respond to Mr. Bunch's observations regarding the Company's generation O&M expense and also respond to Mr. Kenworthy and Mr. Boehnke regarding recommended Integrated Resource Plan ("IRP") modeling assumptions.

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

A. Yes. I am sponsoring the following exhibits:

Exhibit A-191 (RTB-13)	Covert Generating Station Units 1 & 3 LTSA Extra Work;
Exhibit A-192 (RTB-14)	Ludington Pumped Storage Dike Load Center Replacement;
Exhibit A-193 (RTB-15)	Ludington Pumped Storage Oil Water Separator;
Exhibit A-194 (RTB-16)	Ludington Pumped Storage Pony Motor Rotor Cracking and Fretting;
Exhibit A-195 (RTB-17)	Ludington Pumped Storage Distributed Control System Control Relay Replacement;
Exhibit A-196 (RTB-18)	Ludington Pumped Storage Unit Governors;
Exhibit A-197 (RTB-19)	Ludington Pumped Storage Lower Penstock Expansion Joint Chamber Waterstop;

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1	Exhibit A-198 (RTB-20)	Covert Generating Station spare
2		Generator Step-Up (“GSU”) transformer;
3	Exhibit A-199 (RTB-21)	Zeeland Generating Station Phase II Gas
4		Turbine Advanced gas path replacement
5		and axial fuel staging project;
6	Exhibit A-200 (RTB-22)	Zeeland Generating Station Phase I
7		performance report;
8	Exhibit A-201 (RTB-23)	Emergent Reliability Investment for the
9		years 2022 through 2025;
10	~~Exhibit A-202 (RTB-24)~~	~~Jackson Generating Station spare GSU~~
11		~~transformer;~~
12	~~Exhibit A-203 (RTB-25)~~	~~Jackson Generating Station LM1-6~~
13		~~variable inlet guide vane;~~
14	Exhibit A-204 (RTB-26)	Year over Year Generation O&M
15		Expense; and
16	Exhibit A-205 (RTB-27)	Copperleaf Value Model Methodology.

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

18 A. Yes.

19 **REBUTTAL OF ABATE WITNESS YORK**

20 **Q. Please summarize ABATE witness York’s testimony regarding the extra work**
21 **associated with LTSAs with General Electric and Mitsubishi.**

22 A. Based upon my review of Ms. York’s direct testimony beginning at page 19 through page
23 24, Ms. York refers to the projected capital expenditures for LTSA extra work at Covert,
24 Jackson, and Zeeland as speculative or highly speculative. As such, Ms. York
25 recommended the disallowance of \$34.781 million of Covert LTSA extra work in the
26 bridge period and test year, the disallowance of \$5.513 million of Zeeland LTSA extra
27 work in the bridge period and test year, and the disallowance of \$2.430 million of Jackson
28 LTSA extra work in the bridge period and test year.

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1 **Q. Beginning at page 21, line 9, of her direct testimony regarding the Covert LTSA extra**
2 **work, Ms. York states “[b]ecause 1) this category of cost is associated with issues that**
3 **might be discovered that are not covered under the LTSA and 2) historical annual**
4 **amounts vary significantly from year-to-year with no clear trend, I believe it is**
5 **premature to include them in rates at this time.” Do you agree with Ms. York’s**
6 **conclusion?**

7 A. No. As discussed in my direct testimony beginning on page 26, line 19, the Company is
8 conducting major inspections at Covert Units 1, 2, and 3 during the bridge period and test
9 year. Again, beginning on page 61 of my direct testimony, I discuss the performance of
10 59-day major outage inspections for each of the three Covert Units. In addition, beginning
11 on page 62, line 29, through page 68, line 8, I discuss the specific work to be performed
12 during the major inspections including generator inspection, replacement of the generator
13 hydrogen seals, generator rewedge, diaphragm repairs, steam turbine and generator bearing
14 repairs, and HP stop and control valve disassembly, inspection, cleaning, and repair.

15 **Q. How frequently are major inspections performed on the Covert Units?**

16 A. Pursuant to the LTSA with Mitsubishi, these inspections are required every 50,000 hours
17 or approximately every six years. As indicated in my direct testimony, the major inspection
18 on Covert Unit 2 was completed on May 25, 2025. The costs of LTSA extra work on
19 Covert Unit 2 are neither speculative nor are they associated with issues that might be
20 discovered; in fact, the work has been completed and the actual capital expenditures are
21 known. As discussed in Exhibit A-191 (RTB-13), which was originally provided in
22 response to discovery, the actual LTSA extra work performed at Covert Unit 2 totaled
23 \$12.7 million. It is unreasonable to disallow \$12.153 million in projected capital

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expenditures which already reflects an amount which is below the actual capital expenditures incurred.

Q. Were the actual LTSA extra work capital expenditures for Covert Unit 2 consistent with the pre-defined work scope?

A. Yes. A majority of the work performed during the major inspection represented pre-defined work scope. This same pre-defined work scope will be performed during the major inspections for all three units. In addition to the pre-defined work scope, there was both repair work and emergent work tasks (also known as Extra Work Assignments (“EWAs”)) that were also performed. Exhibit A-191 (RTB-13) presents the various types of LTSA extra work capital expenditures including repairs and EWAs.

Q. Does the Company expect the work performed during the Covert Unit 2 outage to be similar to the work performed during the major inspections on Covert Units 1 and 3?

A. Yes. The units are identical, have similar operating history, and the pre-defined work scope is identical. It is also reasonable to expect that the same repair items and EWAs will be discovered during the major inspections on Covert Units 1 and 3. As such, the projected capital expenditures of \$13.103 million for Covert Unit 3 and \$9.525 million for Covert Unit 1 are reasonable and should not be disallowed.

Q. What is your recommendation regarding LTSA extra work for Covert Units 1, 2, and 3?

A. I recommend that the Commission reject Ms. York’s proposed capital expenditure disallowances for the Covert Unit LTSA extra work. The work is well defined based upon recent experience with Covert Unit 2, the work is required pursuant to the Company’s LTSA with Mitsubishi, and failure to perform the work prescribed by the LTSA would

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negate any warranty provisions. The work does include work that, if not performed, would void equipment warranties if the Company continued to operate the units. The work scope that has been performed on Covert Unit 2 and is yet to be performed on Covert Units 1 and 3 is well defined in both my direct testimony and also the work scope presented in Exhibit A-191 (RTB-13). There is no uncertainty as to whether the capital expenditures will be incurred, actual costs support Covert Unit 2 and the performance of identical major inspections on Covert Units 1 and 3 will yield the same results.

Q. Beginning at page 11, line 15, of her direct testimony, Ms. York states “[t]hus, the amounts proposed by Consumers for inclusion in rates are speculative, and may or may not be incurred. As a result, it is premature to include them in rates at this time. Therefore, I recommend the Commission disallow all of Consumers’ projected Bridge Period and Test Year capital expenditures for extra work not covered by the LTSA from recovery through customer rates at this time. A disallowance would be consistent with the Commission’s findings in Consumers’ prior electric rate case.” Do you agree that these costs are speculative?

A. Absolutely not. The Company has carefully planned these major outage inspections and has coordinated their implementation with Midcontinent Independent System Operator, Inc. (“MISO”). The work to be performed by the Company during the major outage inspections has been clearly defined and the Company did provide the basis for the LTSA extra work in my direct testimony beginning on page 69, line 29, through page 70, line 23.

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1 **Q. Beginning at page 22, line 2, of her direct testimony, Ms. York discusses the**
2 **Company's project for Zeeland LTSA extras not included in the contract and states**
3 **that the projections are speculative and out of line with historical actuals. As a result,**
4 **Ms. York states "[t]hus, there is no clear trend in the capital expenditures associated**
5 **with this category, and the amounts proposed by Consumers for inclusion in rates are**
6 **highly speculative and may or may not be incurred. Therefore, I recommend the**
7 **Commission disallow Consumers' total proposed capital expenditures for this extra**
8 **work not included in the LTSA from recovery through customer rates at this time."**
9 **Do you agree with her recommendation?**

10 **A.** No. First, the Company has revised its projected investments for this project for the bridge
11 period. As reflected in Staff witness Maio's Exhibit S-8.1, the Company has reduced its
12 projected bridge period spend from \$4.703 million to \$2.795 million. The LTSA extra
13 work is defined as the work that is not covered under normal planned maintenance in the
14 LTSA. The work does include work that, if not performed, would void equipment
15 warranties if the Company continued to operate the units. Based on historical outage
16 experience and the work that is projected, there are typical discovery items found on this
17 style of gas turbines that are not part of the LTSA planned maintenance scope. Some of
18 the typical items that need to be addressed are labor and material to replace the following:
19 blading, combustion cans, ignitors, vanes/bushings, and any components associated with
20 the compressor as the compressor is not covered under the LTSA.

21 **Q. What is the historical spend for the Zeeland LTSA extra work?**

22 **A.** From 2021 through 2024, the Company invested \$0.463 million in 2021, \$0.522 million in
23 2022, \$15.184 million in 2023, and nothing in 2024. At first glance, the trend in investment

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1 has not been consistent as suggested by Ms. York. However, once you consider that the
2 bulk of the LTSA extra work capital expenditure in 2023 was for the Zeeland Phase I Gas
3 Turbine Advanced gas path replacement and axial fuel staging project and that this project
4 was formally incorporated into the LTSA for 2024, the historic trend makes more sense.

5 **Q. Has the Company incurred actual LTSA extra work capital expenditures at Zeeland**
6 **in 2025?**

7 A. Yes. As presented on Staff witness Maio's Exhibit S-8.0, the Company's actual capital
8 expenditures through June 2025 totaled \$2.120 million. As such the Company's reduced
9 bridge period investment of \$2.795 million is not highly speculative, rather it is relatively
10 certain. The revised project amount of \$2.795 million in the bridge period and projected
11 amount of \$0.810 million in the projected test year are both reasonable and prudent, and
12 supported by the LTSA contract language. As such, I recommend that Ms. York's
13 recommended disallowance be rejected by the Commission. Instead, the Commission
14 should adopt the proposed amounts supported by Ms. Maio.

15 **Q. Beginning at page 23, line 11, of her direct testimony, Ms. York discusses the**
16 **Company's project for Jackson LTSA extras not included in the contract and on**
17 **page 24, line 7, states "[s]imilar to Covert and Zeeland, these are speculative**
18 **projections associated with issues that might be discovered during the bridge period**
19 **and projected test year, based on Consumers' past experience." Ms. York goes on to**
20 **state "the projected costs are significantly out of line with historical costs." Do you**
21 **agree with Ms. York's conclusion?**

22 A. No. I don't agree that the projected costs are significantly out of line with historical costs.
23 The Company's 2021 capital expenditures amount for LTSA extra work was

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1 \$4.192 million as indicated by Ms. York; however, Ms. York's actual cost of a negative
2 \$180,921 for 2022 was incorrect. That negative amount was related to a credit to the 2018
3 LTSA extra work capital expenditure amount. As reflected on my workpaper WP-16, the
4 2022 LTSA extra work capital expenditure amount was \$3.920 million. The LTSA extra
5 work capital expenditure amounts for 2023 and 2024 were \$0.497 million and
6 \$0.330 million, respectively.

7 **Q. Has the Company updated its projected capital expenditures for Jackson LTSA extra**
8 **work?**

9 A. Yes. As presented on Staff witness Maio's Exhibit S-8.1, the Company has increased its
10 projected bridge period spend from \$2.115 million to \$3.472 million. The Company has
11 not changed its projected capital expenditure for LTSA extra work in the test year from
12 \$0.315 million.

13 **Q. Has the Company incurred actual LTSA extra work capital expenditures at Jackson**
14 **in 2025?**

15 A. Yes. As presented on Staff witness Maio's Exhibit S-8.0, the Company's actual capital
16 expenditures through June 2025 totaled \$2.758 million (\$3.426 million through
17 September). As such the Company's increased bridge period investment of \$3.472 million
18 is not highly speculative, rather it is relatively certain. The revised project amount of
19 \$3.472 million in the bridge period and projected amount of \$0.315 million in the projected
20 test year are both reasonable and prudent, and supported by the LTSA contract language.
21 As such, I recommend that Ms. York's recommended disallowance be rejected by the
22 Commission. Instead, the Commission should adopt the proposed amounts supported by
23 Ms. Maio.

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REBUTTAL OF ATTORNEY GENERAL WITNESS COPPOLA

Q. Beginning at page 73, line 2, of his direct testimony, Mr. Coppola summarizes his review of the Company's presentation of proposed capital expenditures for the Covert Generating Station. Mr. Coppola appears to conclude that the Company bought the plant without completing satisfactory due diligence. Do you agree with Mr. Coppola's inference?

A. No. The Company performed a thorough evaluation of the Covert plant purchase and demonstrated that the acquisition was both reasonable and prudent in its 2021 IRP Case No. U-21090, a proposal to which no party contested. The Company's IRP presentation included a projected LTSA capital expenditure amount of approximately \$43 million for the years 2025 through 2027 and a projected LTSA extra work capital expenditure amount of approximately \$24 million.¹ These amounts did not include other capital work related to equipment which was not under warranty by Mitsubishi per the LTSA. The Company did not purchase a brand-new plant, otherwise the acquisition cost would have been significantly higher. Like the purchase of a used car, there is an expectation of incremental maintenance to maintain it; even a new car requires periodic maintenance. Mr. Coppola's hyperbole regarding the lack of technical due diligence should be ignored.

Q. Beginning at page 74, line 11, of his direct testimony, Mr. Coppola discussed two Covert Generating Station projects for which he recommends a disallowance. The first of these two projects is the replacement of the two Load Commutated Inverter ("LCI") Static Frequency Converters ("SFC"). The second project was the upgrade of the station control systems (Netmation). Mr. Coppola goes on to state that

¹ Exhibit A-55 (NJK-6)

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1 “[c]ustomers should not pay for the cost of a recently purchased power plant and
2 shortly thereafter pay for significant upgrades that should have been discovered in
3 the technical due diligence and deducted from the purchase price. I recommend that
4 the Commission disallows the total bridge period capital expenditures of \$4,227,000
5 and remove the \$11,454,000 for the projected test year for the two systems discussed
6 above from inclusion in rate base.” Do you agree with Mr. Coppola’s conclusion and
7 recommendation?

8 A. No. The conclusion that the Company did not perform sufficient due diligence is
9 completely unsupported by Mr. Coppola. As provided in response to discovery, until the
10 Company was in a position to operate the plant, it was not capable of performing the level
11 of equipment condition assessments and detailed engineering evaluations which it employs
12 at all of its other generating plants. The equipment being replaced for both projects is
13 original to the plant, is obsolete, and is no longer supported. The failure to replace this
14 equipment is a threat to continued reliability of the plant as well as supports the Company’s
15 requirements to comply with North American Electric Reliability Corporation (“NERC”)
16 Critical Infrastructure Protection (“CIP”) standards, which emphasize regular updates and
17 maintenance to safeguard control systems. This type of investment is routinely performed
18 at all of the Company’s generating facilities.

19 **Q. Did the Company prepare business cases for each of these projects?**

20 A. Yes. The Company prepared solid business cases for each of these projects which strongly
21 support their implementation. The business case for replacement of the LCI SFCs was
22 included in the Company’s direct filing as Exhibit A-46 (RTB-7) and the business case for
23 the upgrade of the Netmation station control systems was included in the Company’s direct

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1 filing as Exhibit A-48 (RTB-9). As such, I recommend that the Commission reject
2 Mr. Coppola's unsupported recommendation to disallow each of these projects.

3 **Q. Beginning at page 76, line 5, of his direct testimony, Mr. Coppola discusses the**
4 **Company's projected capital expenditures for both the bridge period and test year at**
5 **Ludington Pumped Storage Facility, postures that the work shouldn't be required so**
6 **soon after the units were upgraded and states "The Company has not provided**
7 **sufficient evidence to justify that the capital upgrades it seeks to recover in this rate**
8 **case as [sic] necessary at this time given the recent overhaul of the plant. Therefore, I**
9 **recommend that the Commission [remove] the forecasted bridge period capital**
10 **expenditures of \$15,225,000 and also remove the \$13,282,000 for the projected test**
11 **year from the Company's forecasted capital expenditures for the Ludington power**
12 **plant." Do you agree with Mr. Coppola's conclusion and recommendation?**

13 **A.** Absolutely not. First, as the Company indicated in discovery, the projects proposed for
14 implementation in both the bridge period and test year were not part of the scope for the
15 overhaul and upgrade and, as such, cost for these projects were not included or recovered
16 in the overhaul and upgrade. The overhaul and upgrade project did not obviate the need for
17 maintenance and other work at the plant going forward, particularly for components that
18 were not part of the scope of the overhaul and upgrade. Second, an arbitrary and
19 unsupported recommendation to disallow all capital expenditures at the Ludington facility
20 is absurd and would jeopardize the Company's ability to maintain its Federal Energy
21 Regulatory Commission ("FERC") operating license. The Company received a favorable
22 50-year extension of its operating license through 2069, and the Company has a
23 responsibility to maintain the plant in compliance with that license.

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1 **Q. Are there reasons that these other projects were not included in the overhaul and**
2 **upgrade?**

3 A. Yes. There are at least two reasons that these current projects were not included in the
4 overhaul and upgrade. First, the proposed projects were not necessarily required at the
5 time the scope of the overhaul and upgrade project was developed more than 15 years ago.
6 Second, integration of these projects into the overhaul and upgrade project would have
7 made that project schedule significantly more difficult, likely requiring longer outage times
8 and higher costs during that already complex project. The Company is not proposing in
9 this case to recover costs for work previously performed during the major overhaul and
10 upgrade, but instead proposing to recover costs for new and different work that is needed
11 now.

12 **Q. Is the Company performing other work, not included in this case, to address**
13 **workmanship of the prior overhaul and upgrade contractor?**

14 A. Yes. The Company is already performing corrective work to address workmanship
15 performed by the prior contractor during the overhaul and upgrade project. Costs for that
16 work are being settled to the regulatory asset approved by the Commission in Case No.
17 U-21310 and are not included in this case. This highlights a clear distinction between the
18 new projects being proposed in this case - which were not in scope for the prior major
19 overhaul and upgrade - and the work actually performed during that prior major overhaul
20 and upgrade, portions of which require corrective work.

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1 **Q. Has the Company supported each of the major Ludington projects presented on**
2 **Exhibit A-12 (RTB-3), Schedule B-5.2?**

3 A. Yes. Each of these projects were described in detail in my direct testimony, as
4 acknowledged by Mr. Coppola. In response to discovery, the Company provided business
5 cases for each of the Ludington projects presented on Exhibit A-12 (RTB-3),
6 Schedule B-5.2, pages 8-9. I have attached those business cases as Exhibits A-192
7 (RTB-14) through A-197 (RTB-19). Each of these business cases fully support the
8 decisions regarding the chosen project alternative and speak for themselves. Mr. Coppola
9 argues that the Company didn't provide evidence that these projects weren't part of the
10 overhaul, which I disagree with. Regardless, the business cases provide additional
11 evidence that was already provided to Mr. Coppola.

12 **Q. What is your recommendation regarding Mr. Coppola's recommended disallowance**
13 **of the entirety of the Company's projected Ludington capital expenditures?**

14 A. I recommend that the Commission reject Mr. Coppola's proposed disallowance.
15 Mr. Coppola has not provided any sound basis for not moving forward with any of the
16 projects, most of which are underway. As reflected on Ms. Maio's exhibit S-8.0, the
17 Company has already invested approximately \$3.8 million through June 2025. These
18 projects are both well supported and necessary for the continued safe, reliable, and
19 compliant operation of the Ludington facility.

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1 **Q. Beginning at page 79, line 6, of his direct testimony, Mr. Coppola discusses the**
2 **Company's Waste Water Treatment System project noting that it is still in the**
3 **planning phase of development and doesn't appear that it has advanced sufficiently**
4 **to be completed in the rate case. Mr. Coppola goes on to state "In light of the**
5 **continued operation of the Campbell plan, the uncertainty surrounding the length**
6 **and manner of its operation under FERC jurisdiction, and the still preliminary phase**
7 **of development of the project, I recommend that these costs be removed from the**
8 **Company's forecasted capital expenditures for the bridge period and projected test**
9 **year in the amount of \$17,782,000 and \$9,600,000, respectively." Do you agree with**
10 **Mr. Coppola's conclusion and recommendation?**

11 **A.** Not entirely. As an initial matter, the Company's projected bridge period capital
12 expenditure for this project is \$12.4 million rather than \$17.782 million. This amount is
13 presented on Exhibit A-12 (RTB-3), Schedule B-5.2, page 8, and also on page 98 of my
14 direct testimony. Further, the Company updated the bridge period projection to
15 \$12.420 million in response to discovery from Staff and this adjusted amount is presented
16 on Staff Exhibit S-8.0.

17 The Company agrees that in light of the continuing operation of the Campbell plant
18 pursuant to the emergency orders issued by the U.S. Department of Energy, the Company
19 can no longer achieve project implementation before the end of the projected test year.
20 Despite that fact, continuing operations at Campbell does not stop work on this project.
21 The Company will continue to make progress toward completing this project during the
22 bridge period and test year of this case as can be accommodated by the plant operating
23 status. The continued operating status merely delays completion and project closure; it

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1 does not stop work for this project. The capital expenditures associated with this project
2 should not be disallowed as the project is still viable and necessary. Given the project
3 closure status, the Company will offset the capital expenditure amounts incurred with
4 Allowance for Funds Used During Construction ("AFUDC") such that there is no impact
5 to the revenue requirement in this case. That change is reflected in the updated revenue
6 requirement supported by Company witness Patrick D. Daly in his rebuttal testimony.

7 **Q. Beginning at page 80, line 5, of his direct testimony, Mr. Coppola discusses the other**
8 **capital projects for the generation fleet that are in the planning phase or recently**
9 **entered the design/engineering phase. Mr. Coppola identifies three additional**
10 **projects: (1) Covert spare GSU, (2) Zeeland Phase II gas turbine advanced gas path**
11 **replacement and axial fuel staging project, and (3) Zeeland spare GSU which he**
12 **recommends for disallowance. Mr. Coppola states "[t]he projects are still in the early**
13 **stage of development and not sufficiently certain they will proceed at the forecasted**
14 **cost and timeline. Therefore, I recommend that the Commission remove the**
15 **\$18,722,000 from the Company's forecasted capital expenditures for the projected**
16 **test year." Do you agree with Mr. Coppola's conclusion and recommendation?**

17 **A.** No. I do not agree that these projects should be disallowed. There is no validity to the
18 reasons cited by Mr. Coppola. I will discuss each of these projects separately. As presented
19 on Attorney General Exhibit AG-21, the next phase of the Zeeland spare GSU project is
20 manufacturing and that phase is scheduled to end in April 2026. The spare GSU is not a
21 piece of equipment which will be installed in the plant so the completion of manufacturing
22 and the shipment and storage of the spare GSU at the site are the final steps for completion.
23 As such, there is no uncertainty with respect to project delivery during the projected periods

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1 in this case. The business case for this project was presented in the Company's initial filing
2 as Exhibit A-47 (RTB-8).

3 **Q. Please discuss the capital expenditures for the Covert spare GSU and the Zeeland**
4 **Phase II gas turbine advanced gas path replacement and axial fuel staging project.**

5 A. The Company has been planning for the implementation of these projects for some time;
6 however, neither of the projects were projected to close prior to the end of the test year.
7 As such, both of these projects have been offset with AFUDC such that the projected capital
8 expenditures have no impact on the Company's revenue requirement. Each of the projects
9 have been strongly supported with a business case in response to discovery in this
10 proceeding and neither project should be disallowed. The business cases for the Covert
11 spare GSU and Zeeland Phase II gas turbine advanced gas path replacement and axial fuel
12 staging project are provided as Exhibits A-198 (RTB-20) and A-199 (RTB-21),
13 respectively.

14 **Q. Please discuss the projected benefits of the gas turbine advanced gas path**
15 **replacement and axial fuel staging project on Zeeland Phase II.**

16 A. As presented in Exhibit A-199 (RTB-21), the projected improvements for Phase II include
17 a 51 MW increase in power output and a 2.5% improvement in heat rate, resulting in a
18 \$45.5 million net present value for customers. This improvement is in addition to the same
19 project for Zeeland Phase I.

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1 **Q. Has the Company implemented the gas turbine advanced gas path replacement and**
2 **axial fuel staging project on Zeeland Phase I?**

3 A. Yes. The Company successfully implemented this project on Zeeland Phase I units earlier
4 this year and the results of the project are very positive. I have attached the performance
5 report for the Zeeland Phase I units as Exhibit A-200 (RTB-22).

6 **Q. Please discuss the results of the gas turbine advanced gas path replacement and axial**
7 **fuel staging project on Zeeland Phase I.**

8 A. As presented in Exhibit A-200 (RTB-22), the project was implemented in the spring of
9 2025. Performance data was taken before and after project implementation to validate the
10 effectiveness of the project. The performance data measured in June of this year reflects
11 that Zeeland Unit 1A realized a 25.1 MW improvement in power output and a
12 131.9 Btu/kWh improvement in heat rate. Zeeland Unit 1B realized a 25.6 MW
13 improvement in power output and a 332.5 Btu/kWh improvement in heat rate. Except for
14 the targeted heat rate improvement for Unit 1A, the performance measures exceeded the
15 improvements estimated by the OEM. The project completion allows the Company to
16 serve its customers more reliably and economically for many years to come. The same
17 project on Phase II should be fully supported by the Commission as it provides substantial
18 value to customers.

19 **Q. What is your recommendation for the following projects: (1) Covert spare GSU,**
20 **(2) Zeeland Phase II gas turbine advanced gas path replacement and axial fuel staging**
21 **project, and (3) Zeeland spare GSU?**

22 A. I recommend that the Commission reject Mr. Coppola's proposal to remove the capital
23 expenditures from the projected test year. The Company has provided a sound basis for

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the completion of the Zeeland spare GSU and has offset the remaining two projects with AFUDC, resulting in no impact to the revenue requirement. All three projects are well supported with sound business cases and, as such, should not be disallowed.

REBUTTAL OF STAFF WITNESS MAIO

Q. Beginning on page 7, line 6, of her direct testimony, Ms. Maio discusses her adjustment to the bridge period capital expenditures presented on Staff Exhibit S-8.0. What are your thoughts about Ms. Maio's adjustment?

A. The Company concurs with Ms. Maio's recommendation regarding the Company's adjustments to projects greater than \$1 million presented on Exhibit A-12 (RTB-3), Schedule B-5.2, page 8, in response to discovery question U21870-ST-CE-0002. As presented on Staff Exhibit S-8.0, the adjustments reflect a downward adjustment of \$5.453 million.

Q. Did Ms. Maio's adjustment include all the updates that the Company provided in response to discovery question U21870-ST-CE-0002?

A. No. The Company identified three additional projects in its update to projects greater than \$1 million, namely (1) D.E. Karn ("Karn") Unit 4 Transformer Fire Capital, (2) Covert Main Steam Tee Header Replacements, and (3) Covert Unit 3 Main Steam Tee Header Replacements totaling \$6,920,267. Each of these projects reflect emergent work that was required to be performed and, through June 2025, represented a total actual capital expenditure of \$3,238,054. While the Company's original investment plan included implementation of the projected bridge investment for the named projects, it had to re-prioritize work that was more critical to the generation fleet's continued safe and reliable operation.

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Q. Why has the Company prioritized these emergent projects?

A. After the Company's initial filing in this case, the Company determined that the new projects are higher priority than some level of investment within the originally identified projects on Exhibit A-12 (RTB-3), Schedule B-5.2, page 8. It would be inappropriate to disallow the \$5.453 million originally requested in rates for the bridge period projects based upon the Company's re-prioritization of that capital to critical emergent projects totaling \$4,078,267 for the 2025 calendar year and \$6,920,267 for the entirety of the 16-month bridge period. The Company respectfully requests the Commission to consider inclusion of the emergent projects based upon the Company's re-prioritization. The Company consistently evaluates the priority of various projects and makes adjustments to accommodate the needs of its generation fleet.

Q. Please discuss the Karn Unit 4 transformer fire capital project.

A. In February 2025, the Company experienced a fire on its main unit transformer for Karn Unit 4. The capital expenditures incurred to restore the unit to operation were not originally planned as part of the Company's electric rate case request. However, due to the need to restore the unit to operability in a timely manner, the Company prioritized this investment in order to provide maximum customer value. The table below represents the capacity value that the unit provided in the MISO planning resource auction in March 2025.

	Summer	Fall	Winter	Spring	PY25
	6/1/2025	9/1/2025	12/1/2025	3/1/2026	6/1/2025
	8/31/2025	11/30/2025	2/28/2026	5/31/2026	5/31/2026
Karn 4 (ZRC)	539.0	437.9	390.8	374.2	1,742
ACP (\$/MW-day)	666.5	91.6	33.2	69.6	62.8
Karn 4 (\$k)	32,691	3,610	1,155	2,368	39,824

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As can be clearly seen, the Company made a reasonable and prudent decision in its re-prioritization of capital and should not be penalized for making the best decision on behalf of customers.

Q. Please discuss the Covert Main Steam Tee Header Replacements projects.

A. During the spring 2025 major inspection outage at Covert Unit 2, the high energy piping surveillances ("HEPS") identified the following work requirements which could not be avoided:

- Both the main steam and hot reheat outlet header (external to the heat recovery steam generator ("HRSG")) were fully inspected via either dye penetrant and/or phased array ultrasonic testing down to their respective outlet isolation valves.
 - All rejectable indications, that were deemed not suitable for continued service, were either blended out and/or had welded repairs performed.
 - On the main steam line, the transition from the HRSG outlet manifold (downstream of the safety relief valve) to the low point drain were deemed not suitable for continued service and are being replaced.
- The branch connection connecting the IPS-105 line to the hot reheat line had linear indications at the toe of the weldolet to the 20" steam line. This indication was ground out and a weld repair performed.
- The branch connection connecting the 12" main steam line to the 4" gas turbine cooling steam line, was inspected with no findings and deemed suitable for continued service.
- The 12"x12" tee connecting the main steam line to the high-pressure bypass system was identified to have ID initiated linear cracking on either side of the transition into the branch connection as well as having rejectable indications in the connection welds. This component is being replaced by a fabricated tee assembly following consultation with industry experts.
- The 20" x 20" tee connecting the hot reheat steam line to the hot reheat bypass system was identified as having significant rejectable midwall indications in all three connection welds. This component is being replaced by a fabricated tee assembly following consultation with industry experts.

Based upon the findings during the Covert Unit 2 inspection, the same work is expected during the subsequent Covert Unit 1 and Covert Unit 3 inspections.

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1 **Q. Beginning on page 7, line 21, of her direct testimony, Ms. Maio discusses her second**
2 **adjustment which reflects a proposed \$7.455 million disallowance of test year capital**
3 **expenditures based upon the Company's cost class estimates for each project. Does**
4 **the Company agree with Ms. Maio's proposed disallowance?**

5 A. Ms. Maio's second recommendation is a downward adjustment to 17 projects in the
6 projected test year which are presented on my Exhibit A-12 (RTB-3), Schedule B-5.2,
7 page 9. The proposed adjustment is based on the class cost estimate for these projects
8 which have a class estimate of 2 or higher. In total, Ms. Maio proposes a disallowance for
9 17 projects, all but five of which are non-routine. The total recommended disallowance
10 for the projected test year is \$7.455 million. Ten of the projects are supported by the
11 Company's Association for the Advancement of Cost Engineering ("AACE") Class 2
12 estimates with five projects having an AACE Class 3 estimate.

13 **Q. How does Ms. Maio support Staff's proposed disallowances?**

14 A. Ms. Maio primarily relies on the lower bound of the expected accuracy range for each
15 project's estimate class to support Staff's recommended adjustments. The expected lower
16 bound of the accuracy range for each project's estimate class is shown in Staff
17 Exhibit S-8.4 for the 17 projects for which Ms. Maio proposed a class estimate reduction.

18 **Q. Do you agree with the methodology employed by Ms. Maio to develop her**
19 **recommendations?**

20 A. No. It appears that Ms. Maio performed a thorough review of the various information that
21 the Company included in its filing including direct testimony, exhibits, and Part III filing
22 requirements, as well as the responses that the Company provided to Staff through
23 discovery. Through this process, Staff supported the Company's historical capital

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expenditures as well as most of the Company's updated cost projections for the bridge period. However, I disagree with the use of the low end of the accuracy range for every project in the test year for which Ms. Maio proposes a disallowance.

Q. Please explain what you mean by the low end of the accuracy range.

A. At page 7 of her direct testimony, Ms. Maio included Table 1 - Consumers Energy's Cost Estimate Classes. For each of the estimate class levels, Class 1 through Class 5, with Class 1 being the most mature, an expected accuracy range exists. For each project, Ms. Maio used the low end of the accuracy range to determine a proposed disallowance. For instance, Ms. Maio recommends a \$1.392 million disallowance for the Phase II Gas Turbine Advanced gas path replacement and axial fuel staging project. The total projected capital expenditure for this project in the test year is \$13.923 million and this projected amount includes no contingency. The project cost was based upon a Class 3 estimate, which has an expected accuracy range of -10% to +25%. Ms. Maio used the low end of the low range (-10%) to determine the total proposed disallowance.

Q. What is the impact of using the lower end of the accuracy range for all large generation projects?

A. This approach guarantees that, for the portion of costs the Company incurs above the artificially low estimate, the Company will not recover actual costs expended for the completion of those projects for at least the first year those projects are in service. The Company will begin depreciating that investment as soon as it is in service to reflect the amount of the investment "used up" in the first year of service, but will not be collecting compensation from the customers using it. Assuming the investment is put into rates in the second year, the Company will be compensated for the amount of the investment used

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1 throughout the remaining life of the asset, but it will never be reimbursed for the first year
2 of uncompensated use at a later time.

3 In addition, the use of the low end of the accuracy range guarantees that, for the
4 portion of costs the Company incurs above the artificially low estimate, the Company will
5 not recover any return for its reasonably and prudently incurred investments during the first
6 year that investment is in service for customers.

7 **Q. Do you have other concerns with the application of a disallowance for all 17 projects?**

8 A. Yes. As I discussed in response to Attorney General witness Coppola earlier in this rebuttal
9 testimony, not all of the test year projects are projected to close during the test year.
10 Specifically, there are two projects (Covert spare GSU project and Zeeland Phase II gas
11 turbine advanced gas path replacement and axial fuel staging project) which will not close
12 and their revenue requirement is offset by AFUDC. As such, the \$0.591 million for the
13 Covert spare GSU and the \$1.392 million for the Zeeland Phase II gas turbine advanced
14 gas path replacement and axial fuel staging project should be rejected, regardless of any
15 other determinations.

16 **Q. What is the likely result of only awarding recovery of projects at the low end of the**
17 **accuracy range?**

18 A. The likely result is that the Company will de-prioritize several projects to account for the
19 disallowance to reduce investment to the amount awarded by the Commission. Forgoing
20 execution of the projects that are deprioritized will certainly result in degradation of
21 reliability and safety that those projects would have produced had the projects been
22 completed as planned. It is statistically improbable that all 17 of the Company's larger
23 projects in the test year will result in actual costs at the bottom end of a range of accuracy

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1 based on extent of project development. Because of what that range represents, it is
2 statistically probable that some projects will result in actual costs at the higher end of the
3 range and some at the lower end of the range, such that, collectively, the actual costs will
4 come out about at the estimated value proposed by the Company.

5 **Q. Do you have any other concerns with proposed class estimate disallowances?**

6 A. Yes. As discussed in my direct testimony beginning on page 50, the Company accounts
7 for the uncertainty of less mature estimates by including contingency in its cost estimates.
8 However, based upon prior Commission orders which have consistently disallowed the
9 recovery of contingency in projected capital expenditures, the Company has not included
10 them in its request for investment recovery. As such, the Company's projected capital
11 expenditure amounts already reflect a 5% reduction to the project cost based upon the
12 removal of contingency. As such, the 5% contingency amount is being removed twice
13 with the use of the low end of the accuracy range. At the very least, the recommended
14 disallowance levels should be reduced by the 5% contingency amount that has already been
15 removed from the projected capital expenditures.

16 **Q. What is your recommendation?**

17 A. I recommend that the proposed disallowance based upon the low end of the accuracy range
18 be rejected by the Commission. Based on historical experience, actual cost for a portfolio
19 of projects settle around the projected cost. In 2024, the total capital for all generation
20 projects (excluding the battery storage energy system projects which are offset by AFUDC)
21 implemented in that year was higher than the projected capital for those same projects.
22 This can be validated by reviewing the 2024 projected and actual costs for all generation
23 projects as sponsored in the Company's electric rate cases. Each of the ranges by class

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level have an 80% confidence interval, as such, there is a very low to zero probability that 100% of the projects have an actual cost at the low end of the accuracy range. The probability represented by the range suggests that some estimates will turn out to be low and some will turn out to be right on or nearly right on. The assumption that every single Company estimate will turn out to be inaccurately high, such that the actual cost is at the very bottom of the accuracy range for the estimate, is unreasonable. To the extent that a disallowance is ordered by the Commission, the proposed disallowance amounts for the Covert spare GSU project and the Zeeland Phase II gas turbine advanced gas path replacement and axial fuel staging project should be removed and the disallowance for the remaining projects should be reduced by the 5% contingency amount that has already been removed by the Company.

Q. Beginning on page 12, line 17, of her direct testimony, Ms. Maio states: "Staff recommends the removal of \$2.849 million related to the Emergent Reliability Funding expense included in the Admin/Generation Commons expense since this amount is in addition to the Emergent Reliability Fund expense already incorporated in the historical expense (2024), and there is no assurance that this additional requested amount is needed or will be spent in the test year." Do you agree with Ms. Maio's recommendation?

A. No. While it is a true statement that the actual emergent reliability expense was included in the historical expense for each plant that incurred this expense in 2024, it is not true that the historical amount of emergent reliability expense was included in the forecasted O&M expense for any of the plants in the projected test year. As I discussed in my direct testimony beginning on page 102 of my direct testimony, the O&M expense for the

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projected test year is developed based on maintenance needs at each site or on specific units, rather than a simple escalation of historical year actual expenses. The fact that the projected test year O&M expense of \$103.732 million reflects a \$24.706 million decrease from the historical year, not including escalation, reflects that fact. When considering escalation, the projected test year O&M expense is reduced by \$31.625 million when compared to an amount developed simply by escalating the 2024 actual amount. This result is illustrated on Exhibit A-43 (RTB-4), page 2 of 3, column (i).

Q. Has the Company consistently incurred emergent reliability expense?

A. Yes. For the years 2022 through 2024, the Company incurred emergent reliability expense of \$9.452 million, \$4.866 million, and \$8.346 million, respectively. For 2025 year to date through September, the Company has incurred \$12.744 million in emergent reliability expense. I have presented the details of this spending in Exhibit A-201 (RTB-23). Below is a breakdown of the 2024 emergent reliability expense by plant.

Site	Spend '\$000
Covert	3,987
Hydro	463
Jackson	1,057
Karn	1,530
Ludington	844
Zeeland	465
Total	8,346

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1 **Q. Please provide an example of 2024 emergent reliability expense which demonstrates**
2 **that this historical plant expense is not included in the test year for that same plant.**

3 A. I will use Jackson Generating Station as an example. Of the \$8.346 million emergent
4 reliability expense for the generation fleet in 2024, a total of \$1.057 million was allocated
5 to Jackson Generating Station for both base O&M and major maintenance O&M (primarily
6 major maintenance). The total O&M expense for Jackson Generating Station in 2024 was
7 \$11.616 million, including the \$1.057 million of emergent reliability spending but the
8 projected test year total O&M is only \$10.269 million, a decrease of \$1.347 million. As
9 such, it is evident that the Company didn't simply escalate the historical year O&M
10 expense to arrive at the projected test year O&M expense amount.

11 **REBUTTAL OF MNSC WITNESS COMINGS**

12 **Q. Beginning at page 16, line 10, of his direct testimony, Mr. Comings states "I**
13 **recommend that costs be disallowed for two projects at the Jackson plant. The first**
14 **project is project ID 13478 – 'JGS - Generator Step Up Transformer (GSU) Site**
15 **Spare,' where the Company is requesting \$1.33 million in the bridge period and \$2.33**
16 **million in the projected test period. The second project is project ID 13475, Jackson**
17 **Plant 'LM1-6 VIGV(variable inlet guide vane),' where the Company is requesting**
18 **\$7,885 in the historic test period, \$646,911 in the bridge period and \$960,102 in the**
19 **projected test period." Do you agree with Mr. Comings' recommendation?**

20 A. No. As Mr. Comings indicated in his direct testimony, the Company received approval of
21 these projects in its 2024 electric rate case, Case No. U-21585, and has continued to move
22 forward with their implementation in good faith. Mr. Comings is not proposing to disallow
23 the historical costs and is only recommending the disallowance of the costs which are

RICHARD T. BLUMENSTOCK
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1 above those which were approved in Case No. U-21585. Neither project was projected to
2 close before the end of the test year in Case No. U-21585 and, as such, the amount approved
3 (and ultimately offset by AFUDC) did not reflect the entire cost of the projects.

4 **Q. How much was approved for each project in Case No. U-21585?**

5 A. The Commission approved the recovery of \$1,036,667 in Case No. U-21585 for the
6 Jackson LM1-6 variable inlet guide vane project and \$916,667 for the Jackson spare GSU.
7 The Company has requested a total of \$3,666,667 for the Jackson spare GSU in this
8 proceeding (which includes the \$916,667 previously approved) and \$1,614,698 for the
9 Jackson LM1-6 variable inlet guide vane project (which includes the \$1,036,667 previously
10 approved).

11 **Q. What is the basis for Mr. Comings' proposed disallowance of the capital expenditures**
12 **for the Jackson spare GSU?**

13 A. Mr. Comings identified several reasons for his proposed disallowance including
14 overstatement of the derate (104 MW versus 47 MW), overstatement of the capacity factor,
15 overstatement of the energy value during the potential outage resulting from a failure, and
16 overstatement of the probability that failure will occur.

17 **Q. How does the Company respond to Mr. Comings' concern regarding an**
18 **overstatement of the capacity factor?**

19 A. The Company agrees with this observation made by Mr. Comings. The original modeling
20 projected a capacity factor between 65% and 84%, while historical operation has been
21 between 31% and 39% due to NO_x emission limitations, which materially constrains
22 dispatch and reduces achievable run hours compared to an unconstrained economic model.

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1 ~~Q. How did the Company remedy Mr. Comings' concern regarding an overstatement of~~
2 ~~the capacity factor?~~

3 ~~A. To correct the capacity factor, the Company incorporated historical and forecasted capacity~~
4 ~~factors from the current Power Supply Cost Recovery ("PSCR") case. These values~~
5 ~~incorporate emissions constraints and represent the most accurate planning assumptions.~~

6 **Q. How does the Company respond to Mr. Comings' concern regarding an**
7 **overstatement of the derate?**

8 A. The Company does not agree that the derate amount is overstated. After engineering review
9 with plant operations, the Company confirmed that a 47 MW derate is not physically
10 possible. Each LM GSU has one high-side and two low-side connections, serving two LM
11 units. If the GSU fails, both LM units tied to that transformer must come offline; isolation
12 of a single LM cannot be achieved. This configuration results in a conservative derate of
13 approximately 104 MW based on loss of two LM units and associated loss of steam
14 generation. Maintaining this assumption ensures the analysis reflects actual failure modes
15 and electrical design, not an exaggerated worst case.

16 ~~Q. How does the Company respond to Mr. Comings' concern regarding an~~
17 ~~overstatement of the probability of failure?~~

18 ~~A. Mr. Comings indicated that the original analysis did not incorporate the probability of~~
19 ~~failure into the economic analysis. The Company's revised analysis now integrates~~
20 ~~probability into both the Lost Generation Risk Model and the Financial Risk Model (used~~
21 ~~for potential capacity losses).~~

22 ~~The probability of failure curve was applied as follows:~~

- 23 ~~• 5% in 2026;~~
- 24 ~~• 10% in 2027; and~~

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1 ~~• 15% in 2028, increasing by 5 percentage points annually until December 2039.~~

2 ~~— This probability was applied to the previously calculated capacity loss exposure of~~
3 ~~\$28 million, based on a 1,080-day derate of 104 MW and MISO's rolling three-year Zonal~~
4 ~~Resource Credit ("ZRC") accreditation methodology.~~

5 ~~Q. Please summarize the actions the Company has taken for the spare Jackson GSU~~
6 ~~transformer project.~~

7 ~~A. The Company has prepared a revised concept approval aligned with the Company's~~
8 ~~response to Mr. Comings. I have attached the updated concept approval as Exhibit A-202~~
9 ~~(RTB-24) which reflects the following:~~

- 10 ~~• Capacity factor assumptions now reflect emissions constraints using PSCR-~~
11 ~~based values;~~
- 12 ~~• The 104 MW derate assumption is accurate given the GSU's configuration and~~
13 ~~failure mode; and~~
- 14 ~~• Probability of failure is integrated into the economic model.~~

15 **Q. Beginning at page 19, line 12, of his direct testimony, Mr. Comings states "I**
16 **recommend a disallowance of the \$3.66 million bridge and test period costs being**
17 **requested for this project due to the Company vastly overstating the potential benefits**
18 **of the project." Do you agree with this recommendation?**

19 **A. No.** ~~As discussed above, the Company has revised its economic modeling of this project~~
20 ~~and the resulting analysis supports the customer benefits of implementing this project.~~
21 ~~Beyond the additional modeling,~~ the Company would also dispute the proposed
22 disallowance amount. Of the total project cost, \$916,667 was previously approved by the
23 Commission in Case No. U-21585. Therefore, the maximum disallowance amount should
24 be limited to the incremental amount of \$2.75 million.

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1 **Q. What is the basis for Mr. Comings' proposed disallowance of the capital expenditures**
2 **for the Jackson LM1-6 variable inlet guide vane project?**

3 A. On page 20, line 14, of his direct testimony, Mr. Comings claims that the Company failed
4 to provide satisfactory analytical support for this project.

5 ~~Q. How has the Company responded to Mr. Comings' position regarding a lack of~~
6 ~~analytical support for the Jackson LM1-6 variable inlet guide vane project?~~

7 ~~A. The Company has provided a revised concept approval which is attached as Exhibit A-203~~
8 ~~(RTB-25). The revised concept approval corrects for the overstated capacity factor, like~~
9 ~~the Jackson spare GSU transformer project, and the results still fully support the economic~~
10 ~~viability of the project. In response to discovery, the Company provided a detailed~~
11 ~~explanation of the various models which support the economic calculations.~~

12 **Q. What is your recommendation for this project?**

13 A. I recommend that the Commission reject Mr. Comings proposed disallowance of
14 \$1.61 million for this project. While Mr. Comings indicated he was not recommending
15 disallowance of any historical costs or amounts approved in Case No. U-21585, his
16 recommended disallowance amount did just that. The Commission approved \$1,036,667
17 in Case No. U-21585 and the Company is asking for \$1,614,698 in this case, which
18 includes that amount already approved. As such, while no disallowance amount is
19 warranted, the amount should be no greater than \$578,031. The Company has provided
20 solid evidence that the performance of this project provides benefits to customers, just as
21 it did when first presented in Case No. U-21585.

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1 **Q. Did Mr. Comings make any other recommendations?**

2 A. Yes. Mr. Comings recommended that the Company provide more transparency with
3 economic assessment calculations, including access to any models used in such
4 calculations and auditable derivations of calculations done outside of those models. In
5 addition, Mr. Comings disagreed with the Company's calculation of net energy value
6 ("NEV"). I will address each of these topics separately.

7 **Q. How does the Company respond to this request for increased transparency with**
8 **economic calculations?**

9 A. The Company employs a modeling tool called Copperleaf for its economic modeling for
10 generation projects. The hard-coded calculations contained within Copperleaf are
11 embedded into software and not able to be downloaded to a report or spreadsheet. The
12 Company provided a procedure in response to discovery² which it developed to explain the
13 assumptions made in each risk model and also provided multiple attachments in discovery
14 which included both generic and specific examples of how the calculations are made for
15 the two most used models. I have included the Company-prepared Copperleaf procedure
16 as Exhibit A-205 (RTB-27). In addition, the Company provided attachments in discovery
17 which included PSCR case values which are direct inputs for the models. This should be
18 sufficient to represent that the Company is employing systematic and conservative
19 approach to quantifying the risks associated with not doing a particular project.

² U21870-MNSC-CE-0224_ATT_0001

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1 **Q. Beginning on page 7, line 8, of his direct testimony, Mr. Comings states “The**
2 **Company overstates the NEV of the Jackson plant for 2020 through 2024 by assuming**
3 **lower variable costs than what it reports elsewhere. The Company reported historical**
4 **fuel costs in filing Attachments 126 B, D, F, and J. These documents also provide**
5 **“total production costs.” Do you agree with Mr. Comings’ assessment?**

6 A. No. While the Company does consider major maintenance expense as a cost that varies
7 with equipment condition and operating hours, the Company’s variable costs for purposes
8 of calculating NEV only include variable costs which are directly attributable to operating
9 the unit in the market such as chemical reagent costs.

10 **Q. Do you have any other thoughts about Mr. Comings’ direct testimony?**

11 A. Yes. Mr. Comings’s direct testimony seems to focus on the economics of the Jackson
12 Generating Station as compared to the Company’s other gas generating sites, Covert and
13 Zeeland. The electric rate case is not the proper venue to make decisions about the future
14 of generating assets. The Company’s approved 2021 IRP reflected the operation of
15 Jackson Generating Station through the foreseeable future. To the extent that Mr. Comings
16 takes issue with the plant’s continuing operation, the appropriate venue for that discussion
17 is the Company’s 2026 IRP.

18 **REBUTTAL OF CEO WITNESS BOEHNKE**

19 **Q. Have you reviewed the direct testimony of CEO witness Boehnke?**

20 A. Yes. Mr. Boehnke supports the opportunity to leverage virtual power plants (“VPPs”) to
21 serve customer load in a more affordable manner versus battery storage or gas generation.
22 Mr. Boehnke provides a number of recommendations. I will address his immediate
23 recommendation related to IRP modeling.

RICHARD T. BLUMENSTOCK
U-21870 REVISED REBUTTAL TESTIMONY

1 **Q. Beginning on page 62 of his direct testimony, Mr. Boehnke states that “[t]he**
2 **Commission can require that VPPs be included in the Company’s Integrated**
3 **Resource Planning (IRP) process, not only to support the fulfillment of the**
4 **Company’s past commitment that 20% of energy demand be met by EWR programs**
5 **by 2030 but to expand up on it to deliver affordable services to ratepayers.” Do you**
6 **believe this instant case is the proper forum in which to establish IRP modeling**
7 **requirements?**

8 **A.** No. The Commission has approved IRP Filing Requirements and revisions to those
9 requirements in Case No. U-18461. The Commission has also established Case No.
10 U-21570 to consider updates to the Michigan Integrated Resource Planning Parameters
11 (“MIRPP”) and IRP Filing Requirements in response to Public Act 235 of 2008 (“Act
12 235”) and Public Act 231 of 2023 (“Act 231”). See MPSC Case No. U-21570, February 8,
13 2024 Order, pages 6-8. The Commission should not adopt separate IRP filing requirements
14 in this case that only apply to Consumers Energy, but should instead address IRP modeling
15 requirements in the separate proceedings that the Commission has opened for that purpose.

16 **REBUTTAL OF GLREA WITNESS KENWORTHY**

17 **Q. Have you reviewed the direct testimony of CEO witness Kenworthy?**

18 **A.** Yes. Mr. Kenworthy’s testimony supports a greater focus on the use of distributed energy
19 resources and VPPs to provide less costly resources to serve customers. Mr. Kenworthy
20 provides a number of recommendations. I will address his immediate recommendation
21 related to IRP modeling.

RICHARD T. BLUMENSTOCK
U-21870 REVISED REBUTTAL TESTIMONY

1 **Q. Beginning on page 22 of his direct, Mr. Kenworthy states “[i]n the Company’s last**
2 **IRP settlement, Consumers committed to develop a ‘distributed generation as a**
3 **resource’ modeling approach. That commitment requires bundling customer-level**
4 **distributed solar into a resource that can be evaluated alongside supply-side options,**
5 **consistent with how the Company models energy waste reduction. I recommend that**
6 **Consumers build on this commitment by also modeling Virtual Power Plants (VPPs).**
7 **A VPP integrates distributed generation with storage and demand response,**
8 **producing a more reliable, dispatchable resource with superior capacity value**
9 **compared to distributed generation alone. Adapting the existing distributed**
10 **generation model to include VPP portfolios would allow the Commission to evaluate**
11 **their peak demand impact, transmission and distribution deferral value, and overall**
12 **contribution to system reliability.” Do you agree with Mr. Kenworthy’s**
13 **recommendation?**

14 **A.** Not necessarily. As I stated earlier, I don’t believe this is the proper forum in which to
15 establish IRP modeling requirements. In addition to previously established IRP and
16 MIRPP modeling requirements, the Commission has also established Case No. U-21570
17 to consider updates to the MIRPP and IRP Filing Requirements in response to Act 235 and
18 Act 231. The Commission should not adopt separate IRP filing requirements in this case
19 that only apply to Consumers Energy, but should instead address IRP modeling
20 requirements in the separate proceedings that the Commission has opened for that purpose.

RICHARD T. BLUMENSTOCK
U-21870 REVISED REBUTTAL TESTIMONY

REBUTTAL OF MNSC WITNESS BUNCH

Q. Have you reviewed the direct testimony of MNSC witness Bunch?

A. Yes. Mr. Bunch performed a review of the Company's efforts to increase productivity and the associated support of those efforts in the Company's direct filing in this proceeding.

Q. Beginning on page 25, line 12, Mr. Bunch provides a summary of his review of your testimony with respect to efforts to reduce costs for the generation business. In reference to your direct testimony, Mr. Bunch states, "However, he provides no evidence clarifying the relative contribution from each factor, leaving it unclear whether the decrease reflects real operational efficiency or a shift of costs from the rate case to the REP." Do you agree with Mr. Bunch's summary?

A. Not entirely. While it is true that my direct testimony did not include an all-inclusive plant-by-plant breakdown of the change in O&M expense from the 2024 historical year to the projected test year, I did provide a discussion of the relative change for the major drivers of the change in O&M expense. For instance, I contrasted the change in expense at the Karn site beginning on page 105, line 16, of my direct testimony and showed that the actual increase in O&M expense for the plant was only 0.51% annually. Beginning on page 106, line 9, I discussed the change in O&M expense for the Campbell site, followed by a discussion of the Covert Generating Station, the Ludington Pumped Storage Facility, and the River Hydros. The discussion of the O&M increase for the Covert Generating Station revealed that the increase was primarily due to major maintenance which is based upon both asset condition and also historic maintenance intervals, as discussed in my direct testimony at page 112. When considering the Covert base O&M expense, the total increase from 2024 to the projected test year reflects a total increase of 1.78% or much less than 1%

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on an annualized basis. I have attached my workpaper WP-24 revised (corrected in response to discovery question U21870-ST-CE-0018), as Exhibit A-204 (RTB-26) which provides the year-over-year details for all of the O&M types by unit or plant.

Q. Please discuss the increase to Ludington Pumped Storage Facility base O&M expense.

A. As presented on Exhibit A-204 (RTB-26), the base O&M increased from \$6.017 million in the 2024 historical year to \$6.877 million in the projected test year, an increase of \$0.860 million. As discussed in my direct testimony, there are three projects which led to that increase: (1) FERC Assessments, (2) license initiatives, and (3) fish protection. The Company's 51% share of 2024 historical O&M expense for these projects was \$1.272 million, \$1.872 million, and \$2.135 million, respectively, for a total of \$5.280 million. The Company's share of the projected test year O&M expense for these three projects is \$1.442 million, \$2.321 million, and \$2.361 million, respectively, for a total of \$6.123 million. The increase in projected expense for these three projects totals \$0.843 million; basically comprising the entirety of the base O&M increase. Each of these projects are required as part of the Company's FERC 50-year license and, as such, cannot be avoided. This means the balance of the base O&M expense was basically held to historical levels.

Q. Does the Company's projected test year O&M expense reflect a reduction in expense associated with the removal of renewable energy assets?

A. Not exactly. While it is true that none of the O&M expense associated with renewable energy projects has been included in the projected test year O&M, the Company also removed that same historical expense in order to provide an apples-to-apples comparison.

RICHARD T. BLUMENSTOCK
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1 In actuality, no portion of the 9% annual decrease in generation O&M expense is
2 attributable to the renewable energy plan assets not being recovered through the renewable
3 energy plan.

4 **CONCLUSION**

5 **Q. What will be the impact if the Commission disallows funding based on disallowance**
6 **recommendations from Staff, MNSC, ABATE, and the Attorney General?**

7 A. The Company is requesting recovery for projects that support the ongoing safe and reliable
8 operations of its equipment. The Company ultimately prioritizes its project plans based on
9 funding approved by the Commission. If the Commission chooses to disallow the projects,
10 the Company will not complete the projects and the reliability and safety benefits of the
11 projects will not be realized. This could result in risk to reliability and safety of the
12 generation system.

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

14 A. Yes, it does.

1 JUDGE THOITS: Is the ABATE ready to bind in?

2 MR. CAMPBELL: Yes, Your Honor, we're happy to
3 do so.

4 JUDGE THOITS: All right. Please proceed.

5 MR. CAMPBELL: On behalf of the Association of
6 Businesses Advocating Tariff Equity, this time, I move to
7 bind in the pre-file direct and rebuttal testimony of
8 ABATE witnesses James Dauphinais, Jessica York, Colin
9 Fitzhenry, Chris Walters, and Brian Andrews, and as
10 applicable, I move for the admission of their associated
11 exhibits. Mr. Dauphinais' pre-filed direct testimony
12 consists of a cover page, a table of contents, 26 pages of
13 questions and answers, and an appendix A setting up his
14 qualifications. And along with his pre-file direct
15 testimony, Mr. Dauphinais sponsored Exhibit AB-1. Mr.
16 Dauphinais' pre-filed rebuttal testimony consists of a
17 cover page, a table of contents, and five pages of
18 questions and answers. Ms. Yorks --

19 JUDGE THOITS: All right.

20 MR. CAMPBELL: Sorry.

21 JUDGE THOITS: No. Yeah. Excuse me, Mr.
22 Campbell, but we're going to go one witness at a time.

23 Are there any objections to the admission of
24 direct and rebuttal testimony of James Dauphinais and the
25 admission of Exhibit AB-1?

1 Hearing none. The direct and rebuttal testimony
2 of James Dauphinais is bound into the record, and Exhibit
3 AB-1 is admitted.

**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 generation and distribution of)
 electricity and for other relief.)

Case No. U-21870

Direct Testimony and Exhibits of

James R. Dauphinais

On behalf of

Association of Businesses Advocating Tariff Equity

September 30, 2025



Project 11862

**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	)	Case No. U-21870
the generation and distribution of	)	
electricity and for other relief.	)	
_____	)	

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Direct Testimony of James R. Dauphinais**

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Appendix A: Qualifications of James R. Dauphinais

Exhibit AB-1: Case No. U-21859, Consumers Response to Data Request U21859-DCC-CE-0045.

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) Case No. U-21870
the generation and distribution of)
electricity and for other relief.)
_____)

Direct Testimony of James R. Dauphinais

I. INTRODUCTION

1

2 Q PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

3 A James R. Dauphinais. My business address is 16690 Swingley Ridge Road, Suite 140,
4 Chesterfield, MO 63017.

5 Q WHAT IS YOUR OCCUPATION?

6 A I am a consultant in the field of public utility regulation and a Managing Principal with
7 the firm of Brubaker & Associates, Inc. ("BAI"), energy, economic and regulatory
8 consultants.

9 Q PLEASE DESCRIBE YOUR EDUCATIONAL BACKGROUND AND EXPERIENCE.

10 A This information is included in Appendix A to my testimony.

11 Q ON WHOSE BEHALF ARE YOU APPEARING IN THIS PROCEEDING?

12 A I am appearing on behalf of the Association of Businesses Advocating Tariff Equity
13 ("ABATE"). ABATE consists of large usage customers that purchase substantial
14 amounts of electric power and/or delivery service from Consumers Energy Company

1 (“Consumers” or “Company”). They primarily take service under Consumers’ Rate
2 GPD, Rate GPTU, Rate EIP, Rate GP, Rate GSG-2 and/or Rate LTILRR.

3 **Q HAVE YOU PRESENTED TESTIMONY IN PRIOR ELECTRIC REGULATORY**
4 **PROCEEDINGS BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION**
5 **(“COMMISSION”)?**

6 A Yes. Over my 28 years of employment by BAI, I have provided testimony to the
7 Commission on several occasions regarding issues that include electric rate design,
8 class cost of service, Power Supply Cost Recovery (“PSCR”), standby service rates,
9 resource planning, transmission planning and transmission line routing. In recent years
10 this has included providing testimony in the most recent general rate cases of
11 Consumers (Case Nos. U-20963, U-21224, U-21389 and U-21585), DTE Electric
12 Company (“DTE”) (Case Nos. U-18014, U-18255, U-20162, U-20561, U-20836,
13 U-21297, U-21534 and U-21860) and Indiana Michigan Power Company (Case Nos.
14 U-18370, U-20359 and U-21461) as well as in the original Section 6w State Reliability
15 Mechanism (“SRM”) Capacity Charge proceedings of Consumers (Case No. U-18239)
16 and DTE (Case No. U-18248). I also provided testimony in the 2020 PSCR
17 Reconciliation cases of Consumers (Case No. U-20526) and DTE (Case No. U-20528)
18 as well as the most recent Integrated Resource Plan (“IRP”) proceedings of Consumers
19 Energy Company (Case No. U-21090), DTE (Case No. U-21193) and Indiana Michigan
20 Power Company (Case No. U-21189).

**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 four witnesses. They include myself and my colleagues Jessica A. York, Colin T. Fitzhenry and Christopher C. Walters.

I provide an overview of the direct testimony of ABATE’s witnesses and then address: (i) Consumers’ use of a projected test year, (ii) Consumers’ Distribution Investment Recovery Mechanism (“IRM”) proposal in this proceeding, (iii) Consumers’ proposal in this proceeding to add a facilities allowance for new service under its Large Economic Development Rate (“Rate LED”); and (iv) Consumers’ proposal in this proceeding to modify its charges and credits related to power factor performance under Rate LED in a manner that is inconsistent with the charges and credits related to power factor performance under Rates GSD, GP, GPD, GPTU, EIP and GSG-2 that were just recently approved by the Commission in Case No. U-21585.

Ms. York addresses Consumers’ proposed projected Operation and Maintenance (“O&M”) expenses and certain Consumers’ proposed projected capital expenditures.

Mr. Fitzhenry addresses issues with Consumers’ distribution investment programs included in this rate case filing that have been proposed for recovery through Consumers’ base rate and Distribution IRM proposals in this proceeding.

Mr. Walters addresses Consumers’ proposed Return on Equity (“ROE”) and capital structure.

Table JRD-1 below summarizes ABATE’s recommended downward adjustments to Consumers’ proposed projected test year revenue requirement in this proceeding, inclusive of the amounts Consumers proposes to recover through its

Distribution IRM and proposed DR Surcharge. In total, ABATE's adjustments reduce Consumers' claimed projected test year revenue deficiency of \$460.2 million by \$154.5 million (33.6%). The Capital Expenditure adjustments of Ms. York and Mr. Fitzhenry in Table JRD-1 assume the Commission adopts Mr. Walters' rate of return recommendation of an authorized ROE of 9.5% for Consumers with a 50.00% common equity ratio. If despite Mr. Walters' recommendation the Commission were to instead adopt an authorized ROE greater than 9.5% and/or an equity ratio in excess of 50.00%, the listed downward revenue requirement adjustment associated with capital expenditures would be larger.

TABLE JRD-1	
ABATE	
<u>Revenue Requirement Adjustments</u>	
(\$ Millions)	
<u>Description</u>	<u>Amount</u>
<u>Downward Adjustments:</u>	
O&M Expenses (York)	\$34.1
Production & Dist. Base Rate Cap. Expenditures (York) ¹	\$18.5
Dist. Base Rate Capital Expenditures (Fitzhenry)	\$22.0
Dist. IRM Capital Expenditures (Fitzhenry)	\$5.6
<u>ROE and Capital Structure (Walters)</u>	<u>\$74.3</u>
Total of ABATE Revenue Requirement Adjustments	\$154.5

Table JRD-2, below, summarizes ABATE's recommended minimum downward adjustments to Consumers' proposed investments under its proposal² in this

¹ This is at ABATE's recommended ROE of 9.5% and 50.00% permanent common equity ratio. At Consumers' proposed ROE of 10.25% and permanent common equity ratio of 50.75%, the projected capital expenditure revenue requirement adjustment would be \$19.2 million (Base Rates - York), \$22.9 million (Base Rates - Fitzhenry) and \$5.8 million (Distribution IRM – Fitzhenry).

² Direct Testimony of Consumers witness Myers at 24-27.

proceeding for its Distribution IRM for the periods of May 1, 2026 through April 30, 2027 (Consumers' proposed projected test year in this proceeding) and May 1, 2027 through April 30, 2028. The downward adjustments for the May 1, 2026 through April 30, 2027 period reflect Mr. Fitzhenry's recommended adjustments to Consumers' proposed projected test year distribution Line Reliability – LVD investment programs. The revenue requirement impact of that adjustment is \$5.6 million as shown in Table JRD-1. The recommended downward adjustments for May 1, 2027 through April 30, 2028 are set to maintain the same level of authorized capital expenditures for May 1, 2027 through April 30, 2028 as are approved for May 1, 2026 through April 30, 2027, assuming Consumers is authorized to continue to have a Distribution IRM and ABATE's recommendations for the May 1, 2026 through April 30, 2027 Distribution IRM period are adopted.

TABLE JRD-2		
<u>ABATE Investment Adjustments to Consumers' Distribution IRM Proposal</u>		
(\$ Millions)		
<u>Description</u>	<u>5/1/26 – 4/30/27</u>	<u>5/1/27 – 4/30/28</u>
<u>Downward Adjustments:</u>		
Lines Reliability – LVD	\$108.8	\$108.8
Resiliency – Fractionalization	\$0.0	\$0.0
System Protection	\$0.0	\$0.0
Repetitive Outages – LVD	\$0.0	\$0.0
<u>Vulnerable Communities</u>	<u>\$0.0</u>	<u>\$0.0</u>
Total of ABATE IRM Investment Adjustments	\$108.8	\$108.8

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 for its May 1, 2026 through April 30, 2027 projected test year, or to Consumers' proposed investments under its Distribution IRM for the May 1, 2026 through April 30, 2027 and May 1, 2027 through April 30, 2028 periods.

Q PLEASE BRIEFLY SUMMARIZE YOUR CONCLUSIONS AND RECOMMENDATIONS IN THIS PROCEEDING.

A My conclusions and recommendations are as follows:

1. Consumers, in this proceeding, is requesting to increase its electric rates by \$460.2 million (9.7%)³ fresh on the heels of it being granted a rate increase of \$175.6 million (3.8%) pursuant to the Commission's March 21, 2025 Order in Case No. U-21585⁴ and despite a history, in all but four of its nine most recent general rate cases, of collecting revenues in its historical test year between \$13 to \$26 million in excess of that necessary for it to earn its authorized rate of return.
2. As discussed later in my testimony, Consumers' recent rate increases have been driven by aggressive capital expenditures⁵ coupled with the filing of frequent rate cases and the use of projected rather than historical test years for ratemaking.

³ \$361.7 million through base rates, \$51.9 million through its DR surcharge, \$22.2 million through a proposed Year 3 distribution IRM surcharge, and \$24.3 million through a 12-month distribution Electric Rate Case ("ERC") deferral surcharge

⁴ \$90.2 million through base rates, \$58.5 million through an approved DR surcharge, \$5.2 million through the approved Year 2 distribution IRM surcharge, and \$21.8 million through the approved 12-month distribution Electric Rate Case ("ERC") deferral surcharge.

⁵ With respect to capital expenditures, since at least Case No. U-17990, Consumers in electric rate case applications has generally cited new investments in infrastructure as one of the largest, if not the largest, contributor to its requested rate relief. For example, in Case No. U-17990, Consumers attributed \$161 million of its requested rate relief of \$225 million to investment-related costs (Case No. U-17990 Application at Paragraph 8). As another example, in Case No. U-20134, Consumers identified infrastructure investment contributing \$100 million toward its proposed rate relief of \$58 million (Case No. U-20134, Rate Case Summary at page 3). In the current proceeding, Consumers continues to identify infrastructure investment as a significant driver of it requested rate relief (Rate Case Summary at 2 and 7).

- 1 3. As is also discussed later in my testimony, based on Consumers' track record
2 with respect to the use of a projected test year, the Commission should be
3 vigilant to ensure the following: (i) that the projected expenses and investments
4 included in Consumers' projected test year are truly necessary to provide
5 reliable electric service at the lowest reasonable cost; (ii) that Consumers is
6 essentially irrevocably committed to incur them or otherwise cannot avoid them;
7 and (iii) they are precisely quantified by Consumers with respect to their amount
8 and timing.
- 9 4. To that end, at a minimum, the following adjustments should be made to
10 Consumers' projected test year amounts in this proceeding based on the direct
11 testimony of Ms. York, Mr. Fitzhenry, and Mr. Walters:
 - 12 a. As detailed in Ms. York's direct testimony, Consumers' projected test year
13 O&M expense should be reduced by at least \$34.1 million. This captures
14 her recommended reductions in Consumers' projected O&M spend for
15 various subprograms within the Electric Division – Electric and Common
16 category, and Forestry categories as shown in Table JAY-5 of her direct
17 testimony.
 - 18 b. As detailed in Ms. York's direct testimony, Consumers' projected production
19 (generation) and distribution capital expenditures for the bridge period and
20 test year should be reduced by at least \$358.6 million for the generation and
21 distribution projects identified in Ms. York's Table JAY-6. In total, the
22 projected capital expenditure reductions recommended by Ms. York would
23 reduce Consumers' projected test year return, depreciation expenses, and
24 property taxes by \$18.5 million at ABATE's recommended ROE and
25 common equity ratio for Consumers.
 - 26 c. As detailed in Mr. Fitzhenry's direct testimony, the projected distribution
27 capital expenditures for the bridge period and test year that Consumers
28 proposes to recover through base rates should be reduced by at least
29 \$292.1 million in areas shown in Mr. Fitzhenry's Table CTF-4. In total, these
30 projected distribution capital expenditures reductions, which are in addition
31 to those proposed by Ms. York, would reduce Consumers' projected test
32 year return, depreciation expenses, and property taxes recovered through
33 base rates by an additional \$22.0 million at ABATE's recommended ROE
34 and common equity ratio for Consumers.
 - 35 d. As detailed in Mr. Fitzhenry's direct testimony, the projected distribution
36 capital expenditures for the test year that Consumers proposes to recover
37 through its Distribution IRM surcharge should be reduced by at least \$108.8
38 million in the subareas of the Lines Reliability – LVD IRM cost category
39 shown in Mr. Fitzhenry's Table CTF-3. In total, these projected distribution
40 capital expenditure reductions would reduce Consumers' projected test
41 year return, depreciation expenses, and property taxes that would be
42 recovered through Consumers' Distribution IRM by \$5.6 million at ABATE's
43 recommended ROE and common equity ratio for Consumers.
 - 44 e. As detailed in the direct testimony of Mr. Walters, Consumers should not be
45 authorized an ROE greater than 9.5% or a permanent common equity ratio

1 in excess of 50.00%. Mr. Walters' recommendation would reduce
2 Consumers' projected test year return by \$74.3 million.

3 5. With these adjustments recommended by Ms. York, Mr. Fitzhenry, and Mr.
4 Walters, at least \$154.5 million (approximately 33.6%) of Consumers' proposed
5 \$460.2 million rate increase in this proceeding is unwarranted, unsupported, or
6 both. As a minimum, this portion of Consumers' proposed base rate increase
7 should be denied.

8 6. In addition, for the reasons detailed in my testimony herein and in the direct
9 testimony of Mr. Fitzhenry, the Commission should as a minimum reduce
10 Consumers' proposed level of authorized investment included in its Distribution
11 IRM for the May 1, 2026 through April 30, 2027 (Year 3) period and May 1, 2027
12 through April 30, 2028 (Year 4) period by \$108.8 million.

13 7. The Commission should approve Consumers' proposed Rate LED facilities
14 allowance with sales margins limited to system contribution charge and delivery
15 service charge revenues. This is a reasonable minor reform that would increase
16 the competitiveness of Consumers' Rate LED by reducing the upfront cost for
17 participation by customers under Rate LED.

18 8. The Commission should reject Consumers' proposal in this proceeding to
19 modify its charges and credits related to power factor performance under Rate
20 LED in a manner that is inconsistent with charges and credits related to power
21 factor performance under Rates GSD, GP, GPD, GPTU, EIP and GSG-2 that
22 were just recently approved by the Commission in Case No. U-21585.

23 **II. PROJECTED TEST YEAR**

24 **Q YOU HAVE ALLEGED THAT, ALONG WITH THE PURSUIT OF AGGRESSIVE**
25 **CAPITAL EXPENDITURES, CONSUMERS' USE OF A PROJECTED TEST YEAR IS**
26 **A MAJOR DRIVER OF CONSUMERS' PROPOSED RATE INCREASE IN THIS**
27 **PROCEEDING. PLEASE EXPLAIN WHY THIS IS THE CASE.**

28 **A** The best starting point for exploring this issue is to compare Consumers' own historical
29 and projected test year calculations for this case and its six most recent general rate
30 cases. I present this comparison below in Table JRD-3.

TABLE JRD-3			
Historic Test Year and Projected Test Year			
Rate Sufficiency / (Deficiency)			
<u>Case</u>	<u>Historical Test Year Sufficiency / (Deficiency)</u>	<u>Projected Test Year Sufficiency / (Deficiency)</u>	<u>Difference Between Historical and Projected</u>
U-17990	\$13,967,000	(\$225,413,000)	(\$239,380,000)
U-18322	\$26,118,000	(\$172,758,000)	(\$198,876,000)
U-20134	\$17,354,000	(\$57,900,000)	(\$75,254,000)
U-20697	\$21,835,000	(\$244,357,000)	(\$266,192,000)
U-20963	\$25,071,000	(\$225,102,000)	(\$250,173,000)
U-21224	(\$83,384,000)	(\$266,442,000)	(\$183,058,000)
U-21389	(\$99,164,000)	(\$207,084,000)	(\$107,920,000)
U-21585	(\$47,985,000)	(\$302,579,000)	(\$254,594,000)
U-21870	<u>(\$2,033,000)</u>	<u>(\$435,881,000)</u>	<u>(\$433,848,000)</u>
Total	(\$128,221,000)	(\$2,137,516,000)	(\$2,009,295,000)
Sources:	Case No. U-17990, Exhibit A-1 and Exhibit A-6, Schedule A-1 Case No. U-18322, Exhibit A-1 and Exhibit A-6, Schedule A-1 Case No. U-20134, Exhibit A-1 and Exhibit A-11, Schedule A-1 Case No. U-20697, Exhibit A-1 and Exhibit A-11, Schedule A-1 Case No. U-20963, Exhibit A-1 and Exhibit A-11, Schedule A-1 Case No. U-21224, Exhibit A-1 and Exhibit A-11, Schedule A-1 Case No. U-21389, Exhibit A-1 and Exhibit A-11, Schedule A-1 Case No. U-21585, Exhibit A-1 and Exhibit A-11, Schedule A-1 Case No. U-21870, Exhibit A-1 and Exhibit A-11, Schedule A-1		

1 What this table shows is that even under Consumers' own numbers,
2 Consumers would not have been able to seek the large rate increases it has sought in
3 its last eight general rate cases, and is seeking in this proceeding, until such time
4 Consumers was actually experiencing the costs it was projecting, but for being
5 permitted to use a projected test year. To put it another way, the use of a projected
6 test year allows Consumers to begin recovering "costs" before those costs have been

1 verified as being real and prudently incurred. This has and continues to have several
2 adverse impacts on customers.

3 First, it has caused and continues to cause customers to experience rate
4 increases sooner than they would under the use of a historical test year.

5 Second, it has eliminated and continues to eliminate the incentive for
6 Consumers to contain costs that would otherwise exist due to the regulatory lag effect
7 associated with the use of a historical test year.

8 Third, it has allowed and continues to allow Consumers to fill its projections with
9 proposed capital expenditures and expenses that either Consumers has not irrevocably
10 committed to making or otherwise can avoid if it finds it advantageous to do so to
11 improve its realized rate of return for its shareholders. This can allow Consumers to
12 collect revenue from its customers for capital expenditures or expenses it does not
13 ultimately incur or has not yet incurred when rates are placed into effect. This
14 unreasonably benefits Consumers' shareholders at the expense of Consumers'
15 customers to the extent the Commission Staff and intervenors are unable to uncover
16 and bring to the Commission's attention such problematic projected costs before they
17 are incorporated into Consumers' base rates. This can also unreasonably benefit
18 Consumers' shareholders at the expenses of Consumers' customers to the extent
19 these problematic projected costs are brought to the Commission's attention by the
20 Commission Staff and intervenors, but the Commission chooses not to disallow their
21 inclusion in Consumers' projected test year costs.

22 Finally, the use of a projected test year greatly handicaps the Commission Staff
23 and intervenors in reviewing Consumers' rate filings to ensure the projected capital
24 expenditures and expenses are reasonable because they are not actual capital
25 expenditures and expenses reflected on Consumers' books, but rather projections

1 developed over many separate cost subaccounts and revenue categories. This
2 requires much more time and greater resources than are necessary in a rate
3 proceeding that utilizes a historical test year, all while the rate case timing has been
4 compressed down to a ten-month time frame. As a result, while some inappropriate or
5 unreasonable cost projections may be identified and successfully disallowed as a result
6 of Commission Staff and intervenor review of Consumers' projections, many others
7 may be missed and inappropriately included in Consumers' rates at the expense of its
8 customers, as outlined above.

9 **Q IS THERE ANY EVIDENCE THAT SUGGESTS THAT CONSUMERS HAS**
10 **COLLECTED EXCESSIVE REVENUE AS A RESULT OF BEING ALLOWED TO USE**
11 **A PROJECTED TEST YEAR?**

12 A Yes. As my Table JRD-3 shows, in five of its most recent general rate case filings,
13 Consumers has reported a revenue sufficiency of approximately \$13 to \$26 million for
14 its historical test year. This means that, in those years, Consumers received revenues
15 \$13 to \$26 million higher than necessary to earn its authorized rate of return during
16 those historical test years. If ratemaking with projected test years was working
17 properly, about half the time Consumers' historical test years would have a revenue
18 deficiency and about half the time Consumers' historic test years would have a revenue
19 sufficiency, such that over time on average, Consumers is just receiving enough
20 revenues to earn its authorized rate of return. This has clearly not been happening.

21 It is also important to note that the historical test year values presented in my
22 Table JRD-3 are Consumers' reported historical test year values. If these historical
23 test year values were closely examined, they might very well reveal costs that are not
24 recoverable in rates. As a result, Consumers' actual revenues in excess of its

1 authorized rate of return may have been well in excess of the approximately \$13 to
2 \$26 million it has reported in five of its nine most recent general rate cases.

3 **Q IS THE COMMISSION REQUIRED TO SET RATES USING A PROJECTED TEST**
4 **YEAR?**

5 A No. As the Commission discussed in its November 2, 2009 order in Case No. U-15645,
6 p. 8, Section 6a(1) of Act 286, MCL 460.6a(1), provides that a utility “may use projected
7 costs and revenues for a future consecutive 12-month period” to develop its requested
8 rates and charges. The Commission added that the Staff and intervenors should direct
9 their focus “upon the strengths and weaknesses of the evidentiary presentations of the
10 parties regarding specific expense and revenue projections.” In a case where a utility
11 decides to base its filing on a fully projected test year, however, the utility bears the
12 burden to substantiate its projections.⁶ Recognizing the statutory time constraints
13 present in a base rate case, the Commission has directed utilities to include all
14 evidence (or sources or evidence) in support of their test year projections in their initial
15 rate case filings.⁷ If the utility cannot or will not provide sufficient support for a particular
16 revenue or expense item (particularly for an item that substantially deviates from the
17 historical data), “the Commission may choose an alternative method for determining
18 the projection.”⁸ That alternative method should be the use of the historical test year
19 amount for that item, adjusted for only known and measurable changes to the amount
20 for that item.

⁶ *In re Detroit Edison Application for Rate Increase*, MPSC Case No. U-15768, January 11, 2010 Order, p. 9.

⁷ *Id.*

⁸ *Id.*

Q IF THE COMMISSION ALLOWS CONSUMERS TO USE A PROJECTED TEST YEAR IN THIS PROCEEDING, WHAT DO YOU INSTEAD RECOMMEND TO THE COMMISSION?

A I recommend the Commission continue to be 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 electric service at 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.

ABATE believes the Commission has made progress in this regard with respect to Consumers, starting with Case No. U-20963. However, the drop in Consumers' historical test year revenue deficiency in this proceeding to only approximately \$2.0 million, as shown in Table JRD-3, raises some concern. It is very important the Commission continues the progress it began to make with respect to greater vigilance, starting in Case No. U-20963, to ensure that the risk of Consumers earning a rate of return higher than authorized by the Commission in this proceeding, through abuse of its use of a projected test year, is minimized when Consumers' May 1, 2026 through April 30, 2027 projected test year in this proceeding actually occurs.

1 **III. CONSUMERS' DISTRIBUTION**
2 **INVESTMENT RECOVERY MECHANISM**

3 **Q DOES THE COMPANY CURRENTLY HAVE AN IRM?**

4 A Yes. In Case No. U-21389, the Commission for the first time authorized an IRM for the
5 Company for certain categories of distribution investments in the amount of
6 approximately \$49.3 million for Year 1 (twelve months ending February 28, 2025) and
7 \$49.3 million for Year 2 (twelve months ending February 28, 2026).⁹ It is important to
8 note that the Commission, in Case No. U-21389, denied the Company's request for a
9 Year 3 (twelve months ending February 27, 2027) for its distribution IRM with a
10 proposed investment of \$101.8 million.

11 Specifically, the Commission states:

12 With specific consideration for safety and reliability in making this
13 determination, the Commission accordingly finds the capital programs
14 for LVD Lines Reliability, excluding Circuit Exit Enhancements and
15 ROW/Easement Procurement; Resiliency, excluding Overhead to
16 Underground; and System Protection to be reasonable and prudent for
17 inclusion in the IRM, **with IRM approval for two years, as opposed to**
18 **three, to allow time for the IRM to move forward but for reevaluation**
19 **to take place as to whether the IRM should continue beyond Year**
20 **2.** This review of whether the IRM should continue will consider how the
21 concerns raised by UCC, MNSC, the CEOs, the Attorney General, and
22 others are addressed and whether they outweigh the benefits of the
23 IRM.¹⁰

24 Finally, it is important to note that the Commission reduced Consumers' proposed Year
25 1 and 2 distribution IRM capital investments from Consumers' proposed level of \$101.8
26 million for each year to \$49.3 million for each year.¹¹

27 In Consumers' subsequent rate case proceeding, Case No. U-21585, which
28 was also Consumers' most recent past rate case proceeding, Consumers proposed to
29 dramatically expand its authorized \$49.3 million of capital expenditures for Year 2

⁹ Case No. U-21389 Final Order at 273.

¹⁰ Case No. U-21389 Final Order at 272-273 (emphasis added).

¹¹ Case No. U-21389, Final Order at 273.

(twelve months ending February 28, 2026) for its distribution IRM by 465% to \$278.6 million. The Company proposed to do this based on an asserted desire to align the authorized capital spending for the distribution IRM for Year 2 with the total proposed projected test year capital spending for the three categories of distribution investments that have been authorized for Consumers' distribution IRM. The Company claimed this would maximize the customer benefits of the IRM.¹²

Ultimately, the Commission, in Case No. U-21585, decided that Consumers should be permitted to align the authorized capital spending for the distribution IRM for Year 2 with the total projected test year capital spending for the three categories of distribution investments that have been authorized for Consumers' distribution IRM, but with the latter reduced down from Consumers' proposed \$278.6 million to only \$86.3 million, consisting of \$68.5 million for LVD Lines Reliability, \$12.6 million for Resiliency and \$5.2 million for System Protection.¹³

Q WHAT HAS CONSUMERS PROPOSED FOR ITS DISTRIBUTION IRM IN THIS CURRENT PROCEEDING?

A Consumers' proposal is to: (i) add a Year 3 (corresponding to its proposed projected test year in this proceeding of May 1, 2026 through April 30, 2027) and a Year 4 (May 1, 2027 through April 20, 2028) to its Distribution IRM; (ii) approximately quadruple its annual capital expenditures in the LVD Line Reliability cost category from \$68.5 million per year to \$276.2 million per year; (iii) add a new "Repetitive Outages – LVD" cost category with annual capital expenditures of \$30.3 million; and (iv) add a new "Vulnerable Communities" cost category with annual capital expenditures of

¹² Case No. U-21585, Consumers witness Myers Direct at 29-30.

¹³ Case No. U-21585, Final Order at 364-366.

1 \$30.0 million.¹⁴ In total, for Year 3 of its Distribution IRM, Consumers would increase
2 its authorized annual capital expenditures by \$266.0 million (308%) from its Case No.
3 U-21585 authorized annual capital expenditure level for Year 2 of its Distribution IRM
4 (March 1, 2025 through February 28, 2026), and then maintain that increased level of
5 authorized annual capital expenditures for Year 4 of its Distribution IRM.¹⁵

6 **Q HOW DO YOU RESPOND TO CONSUMERS' DISTRIBUTION IRM PROPOSAL IN**
7 **THIS PROCEEDING?**

8 **A**Under a regime where projected test years are permitted to be used, there is
9 conceptual merit for using a Distribution IRM for distribution investments necessary to
10 meet an urgent and undisputed need that has been robustly demonstrated to be most
11 cost effectively met by making the proposed investments. Specifically, where projected
12 test years are permitted to be used, conceptually, a Distribution IRM can provide
13 greater accountability, transparency and certainty of investment by breaking out project
14 and unit costs, providing for stakeholder input and review, requiring refunds to
15 customers for cost recovery provided for authorized investment levels that were not
16 actually achieved by the utility, and "ring fencing" the included authorized distribution
17 investments into different categories to ensure a utility cannot make up for falling short
18 of authorized spending in one category by making above authorized investments in a
19 different category. However, great care should be taken to ensure: (i) there is in fact
20 an urgent and undisputed need for each included investment and each such investment
21 has been robustly shown to be the most cost-effective way to address the need, (ii) the
22 years authorized for the Distribution IRM do not go beyond the projected test year any
23 more than necessary, and (iii) the categories are not defined overly wide, such that the

¹⁴ Consumers witness Myers Direct at 24-26.

¹⁵ *Id.*

1 utility is able to avoid a greatly needed authorized investment in a cost category by
2 making up for it with investment in the same category that has a lower degree of need.
3 Unless this care is taken, there is a great risk Consumers' Distribution IRM will become
4 a mechanism that allows Consumers to unreasonably and greatly expand its
5 distribution investments at the expense of its ratepayers, regardless of the need and
6 cost effectiveness of those investments, by receiving advanced authorization for such
7 investments well beyond the projected test year and providing single-issue ratemaking
8 surcharge recovery of the costs of those investments from ratepayers between base
9 rate proceedings.

10 Considering all of the foregoing, with respect to Consumers' Distribution IRM
11 proposal in this proceeding, I have a concern with Consumers' very aggressive
12 proposal to approximately quadruple the level of authorized annual capital
13 expenditures proposed in the LVD Line Reliability costs category of \$207.7 million,
14 which accounts for approximately 78% of the total \$266.0 million (308%) increase in
15 annual Distribution IRM capital expenditures that Consumers has proposed in this
16 proceeding. This proposed level of annual investment growth on its face raises a
17 serious question with respect to whether the proposed included investments are in fact
18 urgently and indisputably needed and are the most cost-effective way to address any
19 needs. Furthermore, this magnitude of expansion in annual capital expenditures for
20 the Distribution IRM in this proceeding, if accepted by the Commission as filed, would
21 cause Consumers' Distribution IRM to problematically become a mechanism that
22 allows Consumers to unreasonably and greatly expand its distribution investments at
23 the expense of its ratepayers, regardless of the need and cost effectiveness of those
24 investments.

1 **Q PLEASE EXPLAIN THIS CONCERN FURTHER.**

2 **A In Case No. U-21585, Consumers' last general rate proceeding, Consumers proposed**
3 **a similar very large increase in authorized annual capital expenditures of \$223.9 million**
4 **for the LVD Lines Reliability cost category. The Commission, based on the record in**
5 **that proceeding, ultimately reduced Consumers' proposed increase in annual**
6 **authorized spending in this cost category down to an increase of only \$31.6 million.¹⁶**
7 **This included a 79.4% decrease in Consumers' proposed Zonal Health Improvement**
8 **investments,¹⁷ a 50.2% decrease in Consumers' proposed Secondary Wire Conversion**
9 **investments,¹⁸ and a 61.7% decrease in Consumers' proposed Right of Way**
10 **Acquisition investments.¹⁹**

11 With respect Zonal Health Improvements, among other things, the Commission
12 noted:

13 [W]hile the Commission sees potential value in expanding
14 activities to enhance zonal health, it remains unclear whether the
15 proposed levels of capital investment represent an optimized approach
16 for maximizing customer benefit, including a reduction in SAIDI,
17 particularly given the relatively flat level of expenditures focused on tree
18 trimming. Prior to approving a 500% increase in capital spending for
19 zonal health between the bridge period and test year, the Commission
20 will want to see more analysis of the most cost-effective opportunities to
21 drive improvement in reliability performance, using the results of the
22 recent third-party audit in Case No. U-21305 as a starting point.²⁰

23 With respect to Secondary Wire Conversions, the Commission noted:

24 The Commission finds persuasive the Attorney General's
25 testimony that the company's planned investments target a relatively
26 few number of customers and involves a significant ramp up in
27 spending, from \$1.0 million in the bridge period to over \$28 million in the
28 test year. The Commission finds that additional details supporting the

365. ¹⁶ \$31.6 million = \$68.523 million - \$36.880 million; Case No. U-21585, Final Order at 360 and

¹⁷ 79.4% = \$178.0 million / \$224.2 million; Case No. U-21585, Final Order at 54-56 and 62.

¹⁸ 50.2% = \$14.1 million / \$28.1 million; Case No. U-21585, Final Order at 54-56 and 64.

¹⁹ 61.7% = \$7.4 million / \$12.0 million; Case No. U-21585, Final Order at 54-56 and 62.

²⁰ Case No. U-21585, Final Order at 63.

benefits of these conversions are necessary prior to approval for inclusion in rate base of such a significant increase in expenditures.²¹

Finally, with respect to Right of Way Acquisitions, the Commission noted:

As to the ROW acquisitions, the Commission agrees with the Attorney General's position that the company's evidence supporting the projected expenditure was lacking the detail necessary in terms of specific projects and lines or miles of lines tied to needed easements to be fully supported.²²

Given all of the above, the Commission has set a very high bar for Consumers to demonstrate its similar \$207.7 million request in annual authorized LVD Lines Reliability spending in this proceeding should be approved.

Q WHAT IS YOUR RECOMMENDATION TO THE COMMISSION WITH RESPECT TO THIS ISSUE?

A Based on my testimony above and the direct testimony of ABATE witness Mr. Fitzhenry with respect to the LVD Lines Reliability cost category, I recommend that the Commission, as a minimum, reduce Consumers' proposed annual authorized capital expenditure amount of \$276.2 million per year for the LVD Lines Reliability cost category for Year 3 (twelve months ending April 30, 2027) and Year 4 (twelve months ending April 30, 2028) of Consumers' Distribution IRM by at least \$108.8 million per year. This would reduce the total annual authorized capital expenditures under Consumers' Distribution IRM for Years 3 and 4 to no more than \$243.6 million per year.

²¹ Case No. U-21585, Final Order at 64.

²² Case No. U-21585, Final Order at 64.

IV. RATE LED

Q PLEASE SUMMARIZE THE CHANGES THAT CONSUMERS IS PROPOSING TO ITS RATE LED IN THIS PROCEEDING.

A First, Consumers is proposing to update the production capacity charge under Rate LED to be based on the latest MISO Cost of New Entry (“CONE”).²³

Second, Consumers proposes to offer prospective customers a facilities allowance toward the cost of any incremental distribution investments necessary to serve the customer based on the expected sales margins (the expected contribution toward Consumers’ embedded costs) that would be provided by the customer over the initial five years of service to the customer.²⁴ Consumers notes that five years corresponds to the standard Contribution in Aid of Construction Allowance offered to standard primary customers.²⁵

Finally, Consumers is also proposing to add power factor provisions to Rate LED that mirror those approved by the Commission in Case No. U-21585 for Rates GP, GPD, GPTU and EIP except, instead of applying a charge for power factor below 0.875 and a credit for power factor above 0.875, they would apply a charge for power factor below 0.909 and a credit for power factor above 0.909.²⁶

²³ Consumers witness Connolly Direct at 11.

²⁴ Consumers witness Connolly Direct at 11-12.

²⁵ *Id.*

²⁶ Consumers witness Connolly Direct at 12-13.

Q DO YOU HAVE ANY ISSUE WITH THE UPDATE OF THE RATE LED PRODUCTION CAPACITY CHARGE?

A No. To correctly reflect the incremental cost to providing new service under Rate LED, it is appropriate to update the production capacity charge under the rate to reflect the latest available MISO CONE price for capacity.

Q HOW DO YOUR RESPOND TO CONSUMERS' PROPOSED CHANGE TO RATE LED TO ADD A FACILITIES ALLOWANCE FOR RATE LED FOR PROSPECTIVE CUSTOMERS UNDER THE RATE?

A Depending on circumstances outside the control of prospective customers, there can be significant costs to interconnect the customer to the utility distribution system. The proposed change, which would offer a facilities allowance toward the incremental cost of any required distribution investments necessary to serve a customer, addresses concerns that such prospective customers can have with respect to there being no facility allowance of any amount under Rate LED despite one being available under similar economic development tariffs offered by other utilities, including under DTE's Rate D13.

Q DOES ABATE SUPPORT THIS PROPOSED CHANGE TO ADD A FACILITIES ALLOWANCE TO RATE LED?

A ABATE supports the proposed change, but only to the extent the sale margins used in determining the allowance are limited to the expected system contribution and delivery service revenues of the customer consistent with the Commission's final order in U-21585.²⁷ Expected power supply revenues should not be included. It appears this

²⁷ Case No. U-21585, Final Order at 424-425.

1 is what Consumers means in its proposal, but to be clear, ABATE only supports
2 Consumers' proposal to the extent the sale margins used in determining the allowance
3 are limited to the expected system contribution and delivery service revenues of the
4 customer.

5 ABATE generally supports competitive economic development rates of a
6 reasonable, defined contract term that fully cover the incremental cost to serve the new
7 or expanded load of the participating customer while also providing a contribution
8 toward the utility's embedded costs. This ensures that the remaining customers of the
9 utility are not subsidizing the new or expanded electric service that is being provided,
10 and those customers receiving the benefit of the new or expanded load at some point
11 in the future pay a normally allocated share of the utility's embedded cost of service.
12 Consumers' Rate LED is such an economic development rate. Furthermore, the
13 proposed change in question would improve the competitiveness of Consumers' Rate
14 LED versus other utility economic development rates while continuing to ensure the
15 rate fully covers the incremental cost to provide the new or expanded electric service,
16 while also providing a contribution toward Consumers' embedded costs after the initial
17 five years of service.

18 **Q PLEASE EXPLAIN IN DETAIL WHY CONSUMERS' PROPOSAL TO OFFER A**
19 **FACILITIES ALLOWANCE TO PROSPECTIVE RATE LED CUSTOMERS IS**
20 **REASONABLE.**

21 **A** Other utility economic development rates, such as DTE Rate D13, provide for such an
22 allowance. Furthermore, sales margins (i.e., contribution to Consumers' embedded
23 costs) are provided by Rate LED customers from the system contribution and delivery
24 service charges they pay that would not be provided, but for the new or expanded load

1 of these customers. As a result, it is reasonable to allow Consumers to provide a
2 facilities allowance based on the sales margins that would be provided by the customer
3 through the system contribution and delivery service charges the customer is expected
4 to pay over the first five years of service with Consumers. It would improve the
5 competitiveness of Consumers' Rate LED versus the economic development rates of
6 other utilities while still ensuring the incremental cost to serve the customer and a
7 contribution toward Consumers' embedded costs are still being covered. Finally, as
8 Consumers has noted, five years corresponds to the standard Contribution in Aid of
9 Construction Allowance offered to its standard primary customers.

10 **Q PLEASE EXPLAIN WHY ABATE IS NOT AT THIS TIME SUPPORTIVE OF**
11 **INCLUDING NON-ENERGY POWER SUPPLY REVENUES IN CONSIDERING THE**
12 **MARGINS A RATE LED CUSTOMER WOULD PROVIDE OVER THE TERM OF ITS**
13 **CONTRACT WHEN DETERMINING A RATE LED FACILITIES ALLOWANCE FOR**
14 **THAT CUSTOMER.**

15 A Consumers, in Case No. U-21646, found it necessary to increase the power supply
16 production demand charge due to rising market prices for capacity.²⁸ Given this, Rate
17 LED non-energy power supply revenues are likely just sufficient to cover Consumers'
18 incremental capacity and transmission cost to serve a new Rate LED customer. As a
19 result, ABATE, at this time, cannot support the inclusion of expected Rate LED
20 non-energy power supply charges in the determination of the facilities allowance for a
21 new Rate LED customer. Only expected system contribution charge and delivery
22 service charge revenues should be considered. Again, I believe this is Consumers'
23 intention, but want to be clear that only expected system contribution charge and

²⁸ Case No. U-21646, Consumers' Application, April 26, 2024 at 2-3.

1 delivery service charge revenues should be considered at this time for the Rate LED
2 facilities allowance.

3 **Q HOW DO YOU RESPOND TO CONSUMERS' PROPOSAL TO ADD POWER**
4 **FACTOR PROVISIONS TO RATE LED THAT MIRROR THOSE APPROVED BY THE**
5 **COMMISSION IN CASE NO. U-21585 FOR RATES GP, GPD, GPTU AND EIP**
6 **EXCEPT, INSTEAD OF APPLYING A CHARGE FOR POWER FACTOR BELOW**
7 **0.875 AND A CREDIT FOR POWER FACTOR ABOVE 0.875, THEY WOULD APPLY**
8 **A CHARGE FOR POWER FACTOR BELOW 0.909 AND A CREDIT FOR POWER**
9 **FACTOR ABOVE 0.909?**

10 **A** ABATE supports applying the power factor provisions that the Commission approved
11 in Case No. U-21585 for Rates GP, GPD, GPTU, and EIP to Rate LED customers,
12 given that they pay the same delivery service charges as customers under Rates GP,
13 GPD, GPTU, and EIP. However, ABATE opposes using a 0.909 power factor threshold
14 for determining whether per kVAR charges or credits apply, rather than the 0.875 power
15 factor threshold approved by the Commission in Case No. U-21585 for Rates GP, GPD,
16 GPTU, and EIP.

17 In defending its proposed 0.909 power factor threshold for Rate LED customers,
18 Consumers first points to the power factor provisions of its FERC-jurisdictional
19 Distribution-Transmission Interconnection Agreement ("DTIA") with the Michigan
20 Electric Transmission Company ("METC"), which requires that at system load levels
21 above 90% of peak, Consumers must maintain an average power factor of 0.98 or
22 better across all interconnection points with METC.²⁹ Then it indicates that while
23 historically this has not been an issue for Consumers, customers on Rate LED will have

²⁹ Consumers witness Connolly Direct at 12-13.

1 larger loads than that of Consumers' current customer base and could have a greater
2 impact on the Company's total system power factor.³⁰ However, Consumers provides
3 absolutely no evidence or analysis in its direct testimony to support that either its
4 existing contracted Rate LED customers, or any potential Rate LED customers that
5 are currently in its economic development pipeline, either alone or in aggregate,
6 threaten its ability to comply with the DTIA.

7 Furthermore, Consumers has provided no evidence in direct testimony that, in
8 combination, Consumers' Rate LED delivery service charges, and the application of
9 the power factor provisions for Rates GP, GPD, GPTU, and EIP approved in Case No.
10 U-21585 to Rate LED customers, would not provide sufficient contribution from Rate
11 LED customers toward covering the cost of power factor correction on Consumers'
12 system. Larger customers would have higher demand and a higher level of kVAR
13 deviation for the same amount of power factor deviation. This means that for the same
14 level of power factor deviation, these customers will pay higher delivery service charges
15 and higher per kVAR charges than a smaller customer under Rates GP, GPD, GPTU,
16 or EIP.

17 Finally, it is also important to note that Consumers did not include a similar
18 0.909 power factor threshold for per kVAR charges and credits in its proposed Rate
19 GPD Data Center Load Amendments in Case No. U-21859, despite reporting over
20 15 GW (15,000 GW) of data center load in its economic pipeline and providing a
21 discovery response in that proceeding that showed the vast majority of the proposed
22 data center load additions were 300 MW or larger in size, with some as large as a 1,000
23 MW in size.³¹ Consumers has provided no evidence in direct testimony that the

³⁰ *Id.*

³¹ Case No. U-21859, Consumers' Response to Data Request U21859-DCC-CE-0045. A copy of this Data Request response is provided in Exhibit JRD-1.

1 proposed load additions in its Rate LED economic pipeline, either individually or in
2 aggregate, are comparable in size to the proposed data center load additions in its
3 economic pipeline. This, combined with the fact that Consumers did not propose a
4 similar 0.909 power factor threshold under its proposed Data Center Load
5 Amendments for rate GPD in Case No. U-21859, further illustrates the
6 unreasonableness of Consumers' proposal in this proceeding to set the power factor
7 threshold for per kVAR charges and credits for Rate LED customers to 0.909 power
8 factor rather than 0.875 power factor.

9 **Q WHAT DO YOU RECOMMEND TO THE COMMISSION?**

10 A I recommend that the Commission in this proceeding adopt for Rate LED the same
11 power factor provisions approved for Rates GP, GPD, GPTU, or EIP in Case No.
12 U-21585, including the use of a 0.875 power factor threshold for per kVAR charges and
13 credits. For the reasons I have discussed, the Commission should reject Consumers'
14 proposal to apply a 0.909 power factor threshold for per kVAR charges and credits to
15 Rate LED customers.

16 **Q DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?**

17 A Yes, it does.

1 **Qualifications of James R. Dauphinais**

2 **Q PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.**

3 A James R. Dauphinais. My business address is 16690 Swingley Ridge Road, Suite 140,
4 Chesterfield, MO 63017, USA.

5 **Q PLEASE STATE YOUR OCCUPATION.**

6 A I am a consultant in the field of public utility regulation and a Managing Principal with
7 the firm of Brubaker & Associates, Inc. ("BAI"), energy, economic and regulatory
8 consultants.

9 **Q PLEASE SUMMARIZE YOUR EDUCATIONAL BACKGROUND AND EXPERIENCE.**

10 A I graduated from Hartford State Technical College in 1983 with an Associate's Degree
11 in Electrical Engineering Technology. Subsequent to graduation, I was employed by
12 the Transmission Planning Department of the Northeast Utilities Service Company¹ as
13 an Engineering Technician.

14 While employed as an Engineering Technician, I completed undergraduate
15 studies at the University of Hartford. I graduated in 1990 with a Bachelor's Degree in
16 Electrical Engineering. Subsequent to graduation, I was promoted to the position of
17 Associate Engineer. Between 1993 and 1994, I completed graduate level courses in
18 the study of power system analysis, power system transients and power system
19 protection through the Engineering Outreach Program of the University of Idaho. By
20 1996 I had been promoted to the position of Senior Engineer.

¹In 2015, Northeast Utilities changed its name to Eversource Energy.

1 In the employment of the Northeast Utilities Service Company, I was
2 responsible for conducting thermal, voltage and stability analyses of the Northeast
3 Utilities' transmission system to support planning and operating decisions. This
4 involved the use of load flow, power system stability and production cost computer
5 simulations. It also involved examination of potential solutions to operational and
6 planning problems including, but not limited to, transmission line solutions and the
7 routes that might be utilized by such transmission line solutions. Among the most
8 notable achievements I had in this area include the solution of a transient stability
9 problem near Millstone Nuclear Power Station, and the solution of a small signal (or
10 dynamic) stability problem near Seabrook Nuclear Power Station. In 1993 I was
11 awarded the Chairman's Award, Northeast Utilities' highest employee award, for my
12 work involving stability analysis in the vicinity of Millstone Nuclear Power Station.

13 From 1990 to 1996, I represented Northeast Utilities on the New England Power
14 Pool Stability Task Force. I also represented Northeast Utilities on several other
15 technical working groups within the New England Power Pool ("NEPOOL") and the
16 Northeast Power Coordinating Council ("NPCC"), including the 1992-1996 New York-
17 New England Transmission Working Group, the Southeastern Massachusetts/Rhode
18 Island Transmission Working Group, the NPCC CPSS-2 Working Group on Extreme
19 Disturbances and the NPCC SS-38 Working Group on Interarea Dynamic Analysis.
20 This latter working group also included participation from a number of ECAR, PJM and
21 VACAR utilities.

22 From 1990 to 1995, I also acted as an internal consultant to the
23 Nuclear Electrical Engineering Department of Northeast Utilities. This included
24 interactions with the electrical engineering personnel of the Connecticut Yankee,

1 Millstone and Seabrook nuclear generation stations and inspectors from the Nuclear
2 Regulatory Commission ("NRC").

3 In addition to my technical responsibilities, from 1995 to 1997, I was also
4 responsible for oversight of the day-to-day administration of Northeast Utilities' Open
5 Access Transmission Tariff. This included the creation of Northeast Utilities' pre-FERC
6 Order No. 889 transmission electronic bulletin board and the coordination of Northeast
7 Utilities' transmission tariff filings prior to and after the issuance of Federal Energy
8 Regulatory Commission ("FERC" or "Commission") FERC Order No. 888. I was also
9 responsible for spearheading the implementation of Northeast Utilities' Open Access
10 Same-Time Information System and Northeast Utilities' Standard of Conduct under
11 FERC Order No. 889. During this time, I represented Northeast Utilities on the Federal
12 Energy Regulatory Commission's "What" Working Group on Real-Time Information
13 Networks. Later I served as Vice Chairman of the NEPOOL OASIS Working Group
14 and Co-Chair of the Joint Transmission Services Information Network Functional
15 Process Committee. I also served for a brief time on the Electric Power Research
16 Institute facilitated "How" Working Group on OASIS and the North American Electric
17 Reliability Council facilitated Commercial Practices Working Group.

18 In 1997 I joined the firm of Brubaker & Associates, Inc. The firm includes
19 consultants with backgrounds in accounting, engineering, economics, mathematics,
20 computer science and business. Since my employment with the firm, I have filed or
21 presented testimony before the Federal Energy Regulatory Commission in Consumers
22 Energy Company, Docket No. OA96-77-000; Midwest Independent Transmission
23 System Operator, Inc., Docket No. ER98-1438-000; Montana Power Company, Docket
24 No. ER98-2382-000; Inquiry Concerning the Commission's Policy on Independent
25 System Operators, Docket No. PL98-5-003; SkyGen Energy LLC v. Southern

1 Company Services, Inc., Docket No. EL00-77-000; Alliance Companies, et al., Docket
2 No. EL02-65-000, et al.; Entergy Services, Inc., Docket No. ER01-2201-000;
3 Remediating Undue Discrimination through Open Access Transmission Service,
4 Standard Electricity Market Design, Docket No. RM01-12-000; Midwest Independent
5 Transmission System Operator, Inc., Docket No. ER10-1791-000; NorthWestern
6 Corporation, Docket No. ER10-1138-001, et al.; Illinois Industrial Energy Consumers
7 v. Midcontinent Independent System Operator, Inc., Docket No. EL15-82-000;
8 Midcontinent Independent System Operator, Inc., Docket No. ER16-833-000;
9 Midcontinent Independent System Operator, Inc., Docket No. ER17-284-000; and
10 Midcontinent Independent System Operator, Inc. and Ameren Services Company
11 Docket No. ER18-463-000. I have also filed or presented testimony before the Alberta
12 Utilities Commission, the California Public Utilities Commission, the Colorado Public
13 Utilities Commission, the Connecticut Department of Public Utility Control, the Florida
14 Public Service Commission, the Idaho Public Service Commission, the Illinois
15 Commerce Commission, the Indiana Utility Regulatory Commission, the Iowa Utilities
16 Board, the Kentucky Public Service Commission, the Louisiana Public Service
17 Commission, the Michigan Public Service Commission, the Missouri Public Service
18 Commission, the Montana Public Service Commission, the Nevada Public Utilities
19 Commission, the New Mexico Public Regulation Commission, the Council of the City
20 of New Orleans, the Oklahoma Corporation Commission, the Public Utility Commission
21 of Texas, the Public Service Commission of Utah, the Virginia State Corporation
22 Commission, the Wisconsin Public Service Commission, the Wyoming Public Service
23 Commission, Federal District Court and various committees of the Illinois, Missouri and
24 South Carolina state legislatures. This testimony has been given regarding a wide
25 variety of issues including, but not limited to, ancillary service rates, avoided cost

1 calculations, certification of public convenience and necessity, class cost of service,
2 cost allocation, fuel adjustment clauses, fuel costs, generation interconnection,
3 interruptible rates, market power, market structure, off-system sales, prudence,
4 purchased power costs, resource adequacy, resource planning, rate design, retail open
5 access, standby rates, transmission losses, transmission planning, transmission rates
6 and transmission line routing.

7 I have also participated on behalf of clients in the Southwest Power Pool
8 Congestion Management System Working Group, the Alliance Market Development
9 Advisory Group and several committees and working groups of the Midcontinent
10 Independent System Operator, Inc. ("MISO"), including the Congestion Management
11 Working Group; Economic Planning Users Group; Loss of Load Expectation Working
12 Group; Market Subcommittee; Michigan Transmission Studies Task Force; Planning
13 Subcommittee; Regional Expansion, Criteria and Benefits Working Group; Resource
14 Adequacy Subcommittee (formerly the Supply Adequacy Working Group); and
15 Reliability Subcommittee. I am currently a member of the MISO Advisory Committee
16 in the end-use customer sector on behalf of industrial customer groups in Illinois,
17 Louisiana, Michigan and Texas. I am also the past Chairman of the Issues/Solutions
18 Subgroup of the MISO Revenue Sufficiency Guarantee ("RSG") Task Force.

19 In 2009, I completed the University of Wisconsin-Madison High Voltage Direct
20 Current ("HVDC") Transmission course for Planners that was sponsored by MISO. I
21 am a member of the Power and Energy Society ("PES") of the Institute of Electrical and
22 Electronics Engineers ("IEEE").

23 In addition to our main office in St. Louis, the firm also has branch offices in
24 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 generation and distribution of)
 electricity and for other relief.)

Case No. U-21870

Rebuttal Testimony of

James R. Dauphinais

On behalf of

Association of Businesses Advocating Tariff Equity

October 21, 2025



Project 11862

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	)	Case No. U-21870
the generation and distribution of	)	
electricity and for other relief.	)	
_____	)	

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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	)	Case No. U-21870
the generation and distribution of	)	
electricity and for other relief.	)	
_____	)	

Rebuttal Testimony of James R. Dauphinais

I. INTRODUCTION

1

2 **Q PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.**

3 A James R. Dauphinais. My business address is 16690 Swingley Ridge Road, Suite 140,
4 Chesterfield, MO 63017.

5 **Q ARE YOU THE SAME JAMES R. DAUPHINAIS WHO PREVIOUSLY FILED**
6 **TESTIMONY IN THIS PROCEEDING?**

7 A Yes. I filed Direct Testimony on behalf of the Association of Businesses Advocating
8 Tariff Equity ("ABATE") on September 30, 2025.

9 **Q WHAT IS THE PURPOSE OF YOUR REBUTTAL TESTIMONY?**

10 A My rebuttal testimony addresses the portion of the direct testimony of Michigan
11 Environmental Counsel ("MEC"), Natural Resources Defense Council ("NRDC"), Sierra
12 Club ("SC"), and Citizens Utility Board of Michigan ("CUB") (collectively, "MNSC")
13 Witness Caroline Palmer related to Consumers Energy Company's ("Consumers" or

1 “the Company”) Rate LED.¹ My colleague, Brian C. Andrews, is separately filing
2 rebuttal testimony on behalf of ABATE with respect to the portion of MNSC Witness
3 Palmer’s direct testimony related to cost of service studies.²

4 My silence in this testimony, and that of my colleague Mr. Andrews in his
5 rebuttal testimony, with regard to any issue raised in MNSC Witness Palmer’s direct
6 testimony or the other direct testimonies of intervenors and Staff should not be
7 construed as an endorsement of their respective positions on that issue.

8 **II. RESPONSE TO MNSC WITNESS**
9 **PALMER ON RATE LED FACILITIES ALLOWANCE**

10 **Q PLEASE BRIEFLY SUMMARIZE MNSC WITNESS PALMER’S DIRECT**
11 **TESTIMONY WITH RESPECT TO CONSUMERS’ PROPOSED FACILITIES**
12 **ALLOWANCE FOR RATE LED TO WHICH YOU ARE RESPONDING.**

13 **A** MNSC Witness Palmer recommends that the Michigan Public Service Commission
14 (“MPSC” or “Commission”) reject Consumers’ proposed facilities allowance for Rate
15 LED because she is concerned Consumers has not demonstrated that the total
16 distribution revenues that would be collected from the customer (from the customer’s
17 facilities charge payments and standard distribution charge payments) are sufficient to
18 not only cover the facilities allowance provided to the customer and the cost of the
19 dedicated infrastructure for the customer, but also the marginal cost associated with
20 higher demand on the rest of the shared distribution system. She argues costs for
21 other customers will increase unless this is shown.³

¹ MNSC Witness Palmer Direct at 26-33.

² MNSC Witness Palmer Direct at 5-20.

³ MNSC Witness Palmer Direct at 27-29.

Q HOW DO YOU RESPOND?

A This recommendation should be rejected, and the Commission should approve Consumers' proposed facilities allowance based on system contribution charge revenue and delivery (distribution) revenues that would be collected from the customer, consistent with my direct testimony for the reasons I explained in that testimony.⁴ MNSC Witness Palmer has provided no evidence to support her contention there would be a marginal distribution cost for Consumers to serve a Rate LED customer beyond the cost of dedicated facilities, never mind one beyond the cost of dedicated facilities which would not be fully covered by the remaining distribution facilities charge and standard distribution charge revenues collected from the customer after deducting the customer's facility allowance and the cost for the dedicated facilities necessary to serve the customer. Without such evidence, her argument for rejecting the proposed facilities allowance is purely theoretical and thus baseless. Furthermore, she did not account for system contribution charge revenues, which is another source of sales margins from the customer that would not exist but for the customer taking service from Consumers.

**III. RESPONSE TO MNSC WITNESS
PALMER ON RATE LED DISCOUNT PERIOD**

Q PLEASE BRIEFLY SUMMARIZE MNSC WITNESS PALMER'S DIRECT TESTIMONY WITH RESPECT TO THE DISCOUNT PERIOD FOR RATE LED.

A Currently, the minimum allowed contract term under Rate LED is 15 years, and the maximum allowed contract term is 20 years.⁵ The maximum allowed term of 20 years was added in Case No. U-21389. It was added in response to ABATE testimony recommending a maximum allowed term of 20 years be added to Rate LED to place a

⁴ ABATE Witness Dauphinais Direct at 21-24.

⁵ MPSC No. 14 – Electric, Consumers Energy Company, First Revised Sheet No. D-78.10.

1 reasonable limit on the maximum term that Consumers can negotiate with a customer
2 under Rate LED to protect the rest of Consumers' customers against contract terms
3 that never lead to Rate LED customers paying a normally allocated share of
4 Consumers' embedded cost of service.⁶ In this proceeding, MNSC Witness Palmer
5 recommends that the maximum allowed term for rate LED now be dramatically reduced
6 from 20 years to 7 years.⁷ To try to support her recommendation, she points to a
7 number of utilities that have shorter economic development rate maximum contract
8 terms ranging from 5 to 10 years.⁸ She further argues that Consumers has not justified
9 why it should provide rate discounts for as long as 20 years.⁹

10 **Q HOW DO YOU RESPOND?**

11 A Consumers should be provided sufficient leeway to prudently negotiate a contract term
12 with a prospective Rate LED customer in order to successfully bring that customer to
13 the Consumers service territory. As such, MNSC's proposal to dramatically lower the
14 maximum allowed term for Rate LED from 20 years to seven years is unreasonable
15 and should be rejected. Also, it is important to note that only production cost charges
16 under Rate LED are not at fully embedded costs. Specifically, Rate LED customers
17 pay for transmission based on Consumers' cost for transmission service from MISO,
18 which is ultimately principally based on METC's fully embedded cost for transmission
19 service. In addition, Rate LED customers pay Consumers' fully embedded costs for
20 delivery (distribution) service pursuant to Consumers' standard delivery service rates.¹⁰

⁶ Case No. U-21389, ABATE Witness Dauphinais Direct at 31-32 and Case No. U-21389, March 1, 2024, Order at 252-253.

⁷ MNSC Witness Palmer at 33.

⁸ MNSC Witness Palmer at 32-33.

⁹ MNSC Witness Palmer at 33.

¹⁰ MPSC No. 14 – Electric, Consumers Energy Company, Third Revised Sheet No. D-78.20 and Fifth Revised Sheet No. D-78.30.

1 Thus, the transmission and distribution charges Rate LED customers pay are not being
2 discounted versus what other customers pay. It is only Rate LED production charges
3 that are not based on Consumers' fully embedded costs. However, even though the
4 production charges under Rate LED are not based on Consumers' fully embedded
5 costs for production, they are designed to fully cover Consumers' incremental fixed
6 production costs and incremental variable production costs to serve Rate LED
7 customers. This ensures Consumers' other customers are not subsidizing the
8 production costs Consumers needs to incur to serve Rate LED customers – customers
9 that, in many cases, might not have come to the Consumers service territory, or
10 expanded their operations in the Consumers service territory, but for the availability of
11 Rate LED and its allowed term of up to 20 years.

12 **Q DOES THIS CONCLUDE YOUR REBUTTAL TESTIMONY?**

13 **A** Yes, it does.

1 MR. CAMPBELL: Thank you, Your Honor. Ms.
2 York's pre-direct testimony consists of a cover page, a
3 table of contents, 31 pages of questions and answers, and
4 an appendix A setting up her qualifications, and along
5 with her pre-filed direct testimony, Ms. York sponsored
6 Exhibits AB-2 and AB-3. And Ms. York did not have any
7 rebuttal testimony.

8 JUDGE THOITS: Are there any objections to the
9 admission of this testimony or these exhibits?

10 Hearing none. The direct testimony of Jessica
11 York is bound into the record, and exhibits AB-2 and AB-3
12 are admitted.

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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 generation and distribution of)
 electricity and for other relief.)
 _____)

Case No. U-21870

Direct Testimony and Exhibits of

Jessica A. York

On behalf of

Association of Businesses Advocating Tariff Equity

September 30, 2025



Project 11862

**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	)	Case No. U-21870
the generation and distribution of	)	
electricity and for other relief.	)	
	)	

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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) Case No. U-21870
the generation and distribution of)
electricity and for other relief.)
_____)

Direct Testimony of Jessica A. York

I. INTRODUCTION

1

2 Q PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

3 A Jessica A. York. My business address is 16690 Swingley Ridge Road, Suite 140,
4 Chesterfield, MO 63017.

5 Q WHAT IS YOUR OCCUPATION?

6 A I am a consultant in the field of public utility regulation and a Principal with the firm of
7 Brubaker & Associates, Inc. ("BAI"), energy, economic and regulatory consultants.

8 Q PLEASE DESCRIBE YOUR EDUCATIONAL BACKGROUND AND EXPERIENCE.

9 A This information is included in Appendix A to my testimony.

10 Q ON WHOSE BEHALF ARE YOU APPEARING IN THIS PROCEEDING?

11 A I am appearing on behalf of the Association of Businesses Advocating Tariff
12 Equity ("ABATE"). ABATE consists of large usage customers that purchase substantial
13 amounts of electric power and/or delivery service from Consumers Energy

Company ("Consumers" or "Company"). They primarily take service under Consumers' Rate GPD, Rate GPTU, Rate EIP, Rate GP, Rate GSG-2 and/or Rate LTILRR.

Q WHAT IS THE PURPOSE OF YOUR DIRECT TESTIMONY?

A The purpose of my testimony is to propose certain adjustments to Consumers' requested revenue requirement. In particular, I will address Consumers' projected test year Operation and Maintenance ("O&M") expense. I will also propose some modifications to Consumers' projected capital expenditures. In total, I support a reduction of \$53.248 million to Consumers' claimed revenue deficiency, based on Consumers' proposed Return on Equity ("ROE") of 10.25%. Using Mr. Walters' capital structure of 50% equity, and an ROE of 9.5%, my downward adjustments would total to \$52.613 million on a revenue requirement basis.

My silence with respect to any position taken by Consumers in its Application or Direct Testimony 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:

1. Consumers, in this proceeding, is requesting to increase its electric rates by \$460.2 million.¹ It is also important to note that Consumers' projected costs are not guaranteed to be incurred. However, if the Michigan Public Service Commission ("Commission") allows the use of projected costs, then at a minimum, the following adjustments should be made to the Company's projected test year amounts in this proceeding:
 - a. Consumers' projected test year O&M expense should be reduced by at least \$34.098 million. This captures reductions in the Company's projected O&M

¹ \$435.9 million through base rates, Consumers' proposed DR surcharge and IRM surcharge, and \$24.3 million through its 2024 distribution deferral surcharge.

1 spend for various subprograms within the Electric Division – Electric and
2 Common category, and Forestry categories.

3 b. I recommend that Consumers' projected generation capital expenditures for
4 the Bridge Period and Test Year be reduced by \$42.725 million for the
5 generation projects listed in Table JAY-6. Details supporting this
6 recommendation are provided in Section III of this testimony.

7 c. I recommend that Consumers' projected distribution capital expenditures for
8 the Bridge Period and projected Test Year be reduced by \$315.895 million,
9 as shown in Table JAY-6. Details supporting this recommendation are
10 provided in Section III of this testimony.

11 **II. O&M EXPENSE**

12 **Q PLEASE DISCUSS CONSUMERS' HISTORICAL 2024 OTHER (NON-POWER**
13 **SUPPLY) O&M EXPENSE AND THE AMOUNT OF OTHER O&M EXPENSE**
14 **INCLUDED IN THE PROJECTED TEST YEAR ENDING APRIL 2027.**

15 A As shown in Exhibit A-13 (PDD-42), Schedule C-5.1, the adjusted historical test year
16 level of non-power supply O&M expense for 2024 is \$663.802 million. Consumers
17 projects that non-power supply O&M expenses will increase to \$804.952 million for the
18 test year ending April 2027. This represents an increase of \$141.150 million, or about
19 21.3% relative to the 2024 historical level. The \$141.150 million increase is comprised
20 of inflation adjustments amounting to \$21.974 million, and Other Adjustments
21 amounting to \$119.176 million.² Consumers uses inflation factors based on the
22 Consumer Price Index ("CPI"), as forecasted by S&P Global market Intelligence,³ to
23 project both labor and non-labor O&M expenses.

² Exhibit A-13 (PDD-42), Schedule C-5.1, line 25, columns (d) through (g).

³ Direct Testimony of Patrick Daly at pages 14-15.

1 **Q IS CONSUMERS' PROJECTED TEST YEAR O&M EXPENSE REASONABLE?**

2 A No. I am concerned that Consumers' projected test year O&M expense is excessive
3 and inconsistent with the Company's ongoing efforts to minimize costs through
4 productivity improvements and capital improvement projects.⁴

5 **Q CAN YOU ILLUSTRATE HOW THE PROJECTED O&M EXPENSE FOR THE**
6 **FUTURE TEST YEAR COMPARES TO RECENT HISTORICAL ANNUAL O&M**
7 **SPENDING?**

8 A Yes, this information is presented in Table JAY-1.

TABLE JAY-1			
<u>Annual O&M Cost (\$000)</u>			
<u>Line</u>	<u>Description</u>	<u>Amount</u>	<u>Sources</u>
		(1)	(2)
1	YE Dec 2022	\$ 654,549	See Note 1.
2	YE Dec 2023	682,566	See Note 1.
3	YE Dec 2024	663,802	See Note 2.
4	YE Feb 2025	641,572	See Note 1.
5	YE Feb 2026	647,104	See Note 3.
6	Average	\$ 657,919	
7	FTYE Apr 2027	\$ 804,952	
8	Increase vs. Avg.	22.3%	
Sources and Notes:			
	¹ Actual cost from U-21870-AB-CE-0173.		
	² Exhibit A-13 (PDD-42), Schedule C-5.1.		
	³ Approved cost from U-21870-AB-CE-0173.		

⁴ Direct Testimony of Heidi Myers at 31-32, and Consumers' response to discovery request U21870-AB-CE-0178 (Exhibit AB-2 at 3).

As shown in the table, the Company's actual annual O&M spending shown on lines 1 through 4 has consistently stayed in the range of about \$640 million to \$680 million for various 12-month periods over the last few years. Further, the Commission approved annual O&M expense of just under \$650 million for the test year ending February 2026, which is in line with the average annual O&M spend shown on line 6 of the table.

For the projected test year ending April 2027, the Company requests approval to recover in rates \$804.952 million of annual O&M expense. This represents approximately a 22% increase relative to the average historical level.

Q HAVE YOU IDENTIFIED SPECIFIC AREAS OF PROJECTED O&M EXPENSE FOR WHICH YOU BELIEVE ADJUSTMENTS ARE WARRANTED?

A Yes. I recommend adjustments to the Company's projected test year O&M expense for programs included in the following categories:

- Electric Division – Electric and Common
- Forestry

II.A. Electric Division – Electric and Common

Q PLEASE DESCRIBE THE ELECTRIC DIVISION – ELECTRIC AND COMMON O&M EXPENSE CATEGORY.

A As shown on the Company's Exhibit A-13 (PDD-42), Schedule C-5.1, line 1, the Company forecasts test year O&M spending in this category of \$300.994 million, representing an increase of \$54.373 million or approximately 22% from the actual 2024 spending level. As shown on that exhibit, the projected test year spending for this category is comprised of \$10.185 million of inflation adjustments and \$44.188 million of Other Adjustments.

1 The Company includes projected O&M expenses for multiple programs and
2 subprograms within this line item, which are discussed in the direct testimony of
3 Company witness Michael Kelly. The subprograms for which I recommend
4 adjustments to Consumers' projected test year O&M expenses fall into the following
5 categories:

- 6 • Non-Forestry Reliability
- 7 • Operations, Maintenance and Metering without Service Restoration
- 8 • Field Operations

9 **II.A.i. Non-Forestry Reliability**

10 **Q PLEASE DESCRIBE THE SUBPROGRAMS CONTAINED IN THIS O&M EXPENSE**
11 **CATEGORY FOR WHICH YOU RECOMMEND ADJUSTMENTS.**

12 A Non-Forestry Reliability includes O&M expenses for Low Voltage Distribution ("LVD")
13 Lines Reliability, High Voltage Distribution ("HVD") Lines Reliability, HVD Pole
14 Inspections, LVD Substations Reliability and HVD Substations Reliability.⁵ I have
15 concerns with Consumers' projected test year O&M expense for LVD Lines Reliability,
16 HVD Lines Reliability, and LVD Substations Reliability.

17 **Q WHAT IS CONSUMERS' PROJECTED TEST YEAR O&M EXPENSE FOR THESE**
18 **SUBPROGRAMS?**

19 A This information is shown in Table JAY-2.

⁵ Exhibit A-124 (MPK-14), lines 4 through 8.

TABLE JAY-2						
<u>Non-Forestry Reliability O&M (\$000)¹</u>						
Line	Description	2024 Actual Amount	Projected Test Year Amount	Test Year vs. 2024	5-year Average	Test Year vs. 5-Yr Avg.
		(1)	(2)	(3)	(4)	(5)
1	LVD Lines Reliability	\$ 580	\$ 8,000	1280%	\$ 574	1295%
2	HVD Lines Reliability	109	891	715%	214	316%
3	LVD Substations Reliability	3,565	5,475	54%	2,964	85%
4	Total	\$ 4,254	\$ 14,366	238%	\$ 3,752	283%

Source:
¹ Exhibit A-124 (MPK-14).

- 1 **Q PLEASE DESCRIBE YOUR CONCERNS WITH CONSUMERS' PROJECTED O&M**
2 **EXPENSE FOR THE SUBPROGRAMS INCLUDED IN TABLE JAY-2.**
- 3 A As is evident from the table, Consumers' projected O&M expense for these
4 subprograms drastically exceeds the historical five-year average and historical actuals
5 for 2024. Further, the Company's Exhibit A-128 (MPK-18), page 1 of 6, shows that
6 these increases are in large part due to "Other Adjustments." Specifically, for the
7 projects listed in Table JAY-2, the "Other Adjustments" account for \$10.003 million⁶ or
8 99% of the increase from 2024 to the future test year.
- 9 My concern is that the "Other Adjustments" have not been adequately
10 supported.

⁶ Exhibit A-128 (MPK-18), page 1, sum of column (i), lines 3 through 5.

1 **Q WHY DO YOU SAY THE “OTHER ADJUSTMENTS” AMOUNTS HAVE NOT BEEN**
2 **ADEQUATELY SUPPORTED?**

3 A I state this because the Company’s testimony does not specifically describe or show
4 the basis for how it derived these amounts. Mr. Kelly’s direct testimony makes relatively
5 vague statements about how the projected test year amounts were determined.
6 Specifically, he provides the following descriptions:

7 *LVD Lines Reliability*

8 This spending amount is based on the Company’s costs to complete the
9 inspection and maintenance work described above. In particular, the
10 Company is projecting to spend \$3,500,000 in the test year on
11 maintaining disconnect switches, \$2,200,000 on the groundline pole
12 inspection program, and \$500,000 on padmount inspections. The
13 remaining \$1,800,000 will be spent on the other LVD inspections
14 defined in the Reliability Roadmap.⁷

15 *HVD Lines Reliability*

16 This spending amount is based on the projected amount of work
17 expected in this sub-program, specifically HVD pole inspections, testing
18 of MABS and MOABS battery replacements. The increase in spending
19 is being driven by increased inspections and testing to support projected
20 investment increases in the HVD Lines Reliability capital program.⁸

21 For the LVD Substation Reliability category, the Company’s testimony simply
22 comments on reasons why the projected O&M is increasing, rather than describing a
23 basis for the cost estimate. Specifically, it states the following:

24 *LVD Substation Reliability*

25 The Company is increasing the O&M spending in the substation O&M
26 programs to get onto the nominal cycles provided in the ESR-1
27 guidelines and clear maintenance backlogs. The projected spending
28 level in the instant case will accomplish this.⁹

29 Lastly, in response to discovery request U21870-ST-CE-0015 (included as
30 Exhibit AB-2 at 4-5), the Company admitted that the “Other Adjustments” column simply

⁷ Direct Testimony of Michael Kelly at 130.

⁸ *Id.* at 132.

⁹ *Id.* at 135-136.

reflects the difference between Consumers' historical actual spend and its projected test year spend. While the referenced discovery response pertains to projected generation costs, it appears the same explanation applies to the Company's projected distribution costs.

Q WHAT IS YOUR RECOMMENDATION WITH RESPECT TO THE COMPANY'S PROJECTED TEST YEAR O&M EXPENSE FOR THE SUBPROGRAMS LISTED IN TABLE JAY-2?

A I recommend reducing the projected O&M expense by \$10.003 million, which is the amount of "Other Adjustments" included in the projections.

II.A.ii. O&M and Metering without Service Restoration

Q PLEASE DESCRIBE THE SUBPROGRAMS CONTAINED IN THIS O&M EXPENSE CATEGORY.

A This category of spend includes O&M expenses for several subprograms, which are shown on Exhibit A-124 (MPK-14), lines 9 through 22. My testimony will address Consumers' projected expenses for a subset of these subprograms including HVD Lines Demand, LVD Substation Demand, HVD Substations Demand, Staking, and Meter Services.

Q WHAT IS CONSUMERS' PROJECTED TEST YEAR O&M EXPENSE FOR THESE SUBPROGRAMS?

A This information is shown in Table JAY-3.

TABLE JAY-3						
<u>O&M and Metering without Service Restoration (\$000)¹</u>						
Line	Description	2024 Actual Amount (1)	Projected Test Year Amount (2)	Test Year vs. 2024 (3)	5-year Average (4)	Test Year vs. 5-Yr Avg. (5)
1	HVD Lines Demand	\$ 898	\$ 2,979	232%	\$ 790	277%
2	LVD Substations Demand	4,302	6,398	49%	3,720	72%
3	HVD Substations Demand	4,050	5,311	31%	3,177	67%
4	Staking	6,148	13,948	127%	3,999	249%
5	Meter Services	11,165	17,088	53%	9,856	73%
6	Total	\$26,564	\$ 45,725	72%	\$21,542	112%

Source:
¹ Exhibit A-124 (MPK-14).

1 **Q PLEASE DESCRIBE YOUR CONCERNS WITH CONSUMERS' PROJECTED O&M**
2 **EXPENSE FOR THE SUBPROGRAMS INCLUDED IN TABLE JAY-3.**

3 A As shown in the table, Consumers' projected O&M expense for these subprograms
4 drastically exceeds the historical five-year average and historical actuals for 2024. In
5 addition, the Company's testimony and workpapers do not clearly support such
6 significant increases in O&M spending relative to the historical amounts.

7 **Q HOW HAS THE COMPANY DEVELOPED ITS PROJECTED TEST YEAR O&M FOR**
8 **EACH OF THESE SUBPROGRAMS?**

9 A In some cases, the Company's testimony provides a high-level description of its
10 approach to developing its projected O&M spending. In other cases, rather than
11 describing the basis for its projection, the Company focuses on why the projected
12 spending level is higher than historical amounts. Consumers witness Mr. Kelly's direct
13 testimony provides the following information in this regard:

1 The projected spending amount for HVD Lines Demand was determined
2 based on the projected number of HVD lines work orders that the
3 Company will have to complete in the test year.¹⁰

4 Regarding LVD and HVD Substations Demand programs, the Company states:

5 The Company is increasing the O&M spending in all four substation
6 O&M programs to get onto the nominal cycles provided in the ESR-1
7 guidelines and clear maintenance backlogs. The projected spending
8 level in the instant case will accomplish this.¹¹

9 Regarding Staking, the Company explains:

10 Spending in this subprogram is primarily driven by staking request
11 volume (units)...An anticipated volume increase of 7% is included in the
12 test year projection relative to 2024 contract services.¹²

13 The Company also notes that its test year projection for contractor services related to
14 staking requests includes an anticipated unit cost increase.¹³

15 Regarding Meter Services, the spending amounts were determined by
16 considering projected workload.¹⁴ The Company projects a volume of work based on
17 historical data and expected growth from areas like New Business.¹⁵

18 **Q HAS THE COMPANY PROVIDED ITS CALCULATIONS OF THE PROJECTED TEST**
19 **YEAR SPEND FOR THESE SUBPROGRAMS?**

20 **A** While the spending projections are shown in various exhibits, such as Exhibit A-128
21 (MPK-18), the supporting data included in those exhibits reflects underlying inputs that
22 do not explicitly show how the Company arrived at its test year projections. For
23 example, while the projected spend for HVD Lines Demand is based on a projected
24 number of work orders,¹⁶ Mr. Kelly's direct testimony does not appear to identify the

¹⁰ Direct Testimony of Michael Kelly at 140.

¹¹ *Id.* at 142-143.

¹² *Id.* at 149-150.

¹³ *Id.* at 150.

¹⁴ *Id.* at 156.

¹⁵ *Id.* at 156.

¹⁶ *Id.* at 140.

number of historical actual or projected work orders that form the basis of the projection. Similarly, Mr. Kelly's direct testimony does not appear to identify the expected volume of work driving the increase in Meter Services projected spending.

In addition, the Company projects a 7% increase in the volume of staking requests, despite historical data showing significant year-over-year volatility with no apparent trend.¹⁷

Q WHAT IS YOUR RECOMMENDATION REGARDING THE PROJECTED O&M EXPENSES FOR THESE SUBPROGRAMS?

A In order to address the concerns identified above, I recommend reducing the projected O&M expense for these subprograms by \$18.118 million. This is equivalent to the removing the "Other Adjustments" for these subprograms shown on Exhibit A-128 (MPK-18), lines 7 through 9, and lines 11 and 12, and brings the projected spend more in line with the five-year average.

II.A.iii. Field Operations

Q PLEASE DESCRIBE THE SUBPROGRAMS CONTAINED IN THIS O&M EXPENSE CATEGORY.

A This category of spend includes O&M expenses for several subprograms, which are shown on Exhibit A-124 (MPK-14), lines 25 through 33. My testimony will address Consumers' projected expenses for the Training subprogram included in this category of spending.

¹⁷ Direct Testimony of Michael Kelly at 151 (Figure 51).

1 Q WHAT IS CONSUMERS' PROJECTED TEST YEAR O&M EXPENSE FOR THE
2 TRAINING SUBPROGRAM?

3 A This information is shown in Table JAY-4.

TABLE JAY-4						
<u>Field Operations (\$000)¹</u>						
<u>Line</u>	<u>Description</u>	<u>2024 Actual Amount (1)</u>	<u>Projected Test Year Amount (2)</u>	<u>Test Year vs. 2024 (3)</u>	<u>5-year Average (4)</u>	<u>Test Year vs. 5-Yr Avg. (5)</u>
1	Training	\$11,107	\$ 15,833	43%	\$10,070	57%
Source:						
¹ Exhibit A-124 (MPK-14).						

4 Q HOW HAS THE COMPANY DEVELOPED ITS PROJECTED TEST YEAR O&M FOR
5 THE TRAINING SUBPROGRAM?

6 A The Company states that the expenses for this subprogram were determined based on
7 the number of employees, apprentices, and external candidates, multiplied by the
8 expected hours of training they will receive each year.¹⁸

9 Q WHAT ARE YOUR CONCERNS REGARDING THE PROJECTED TEST YEAR O&M
10 FOR TRAINING?

11 A As shown in the table, the projected test year spend is significantly in excess of
12 historical amounts. While the calculation described by Mr. Kelly does not appear to be
13 included in his testimony or exhibits, Consumers' witness Caitlin Tetrick at least
14 identifies the expected number of employees required to implement the Company's

¹⁸ Direct Testimony of Michael Kelly at 168.

1 HVD and LVD workplan.¹⁹ However, it remains unclear what assumptions the
2 Company has made with respect to the new number of employees, apprentices, and
3 external candidates that will actually require training during the projected test year, and
4 whether that projection is reasonable and likely to be accurate. Further, the Company
5 acknowledges in the testimony of Ms. Stewart and Mr. Blumenstock that challenges in
6 obtaining the necessary crews can occur, resulting in projects not being completed as
7 planned.²⁰

8 **Q WHAT IS YOUR RECOMMENDATION REGARDING O&M FOR TRAINING?**

9 A In order to address the concerns described above, I recommend reducing the
10 Company's projected test year O&M expense by \$4.793 million, as shown on Exhibit
11 A-128 (MPK-18), line 21. This adjustment brings this projected test year spend closer
12 in line with the five-year average.

13 **II.B. Forestry**

14 **Q PLEASE DESCRIBE THE FORESTRY O&M EXPENSE CATEGORY.**

15 A As shown on the Company's Exhibit A-13 (PDD-42), Schedule C-5.1, line 2, the
16 Company forecasts test year O&M spending in this category of \$186.684 million,
17 representing an increase of \$76.459 million or approximately 69% from the actual 2024
18 spending level.

19 The Company includes projected O&M expenses for its Line Clearing Program
20 in this category, which are discussed in the direct testimony of Company witness Sara
21 Stewart. The Line Clearing Program is divided into two parts: 1) HVD Line Clearing

¹⁹ Exhibit A-178 (CMT-1) and Exhibit A-179 (CMT-2).

²⁰ Direct Testimony of Mr. Blumenstock at 114; Direct Testimony of Ms. Stewart at 19.

1 and 2) LVD Line Clearing.²¹ My concerns are associated with the Company's projected
2 test year O&M for the HVD Line Clearing Program.

3 **Q WHAT IS CONSUMERS' PROJECTED TEST YEAR O&M EXPENSE FOR THE HVD**
4 **LINE CLEARING PROGRAM?**

5 A Consumers projects test year O&M of \$11.840 million for the HVD Line Clearing
6 Program.²² However, actual spending on this subprogram has averaged about
7 \$10.586 million from 2020 through 2024.²³ Thus, Consumers' projected O&M for this
8 subprogram represents an increase of about 12% relative to the historical average.

9 **Q WHAT ARE YOUR CONCERNS WITH THE COMPANY'S PROJECTED O&M**
10 **SPENDING FOR THE HVD LINE CLEARING PROGRAM.**

11 A My concern is that Consumers' projection may be overstated. As shown in Figure 1 on
12 page 12 of Ms. Stewart's direct testimony, the Company has consistently underspent
13 its planned HVD Line Clearing O&M amounts from 2020 through 2024. Ms. Stewart's
14 Figure 1 shows that, in total, the Company underspent its planned O&M by about 10%
15 from 2020 through 2024, while successfully clearing its planned number of miles each
16 year. Figure 11 on page 34 of Ms. Stewart's testimony shows that, on an annual basis
17 through 2030, the Company expects to continue clearing a similar number of miles of
18 HVD lines each year, using the same number of crews that have been used for several
19 years.

²¹ Direct Testimony of Sara Stewart at 3.

²² Exhibit A-170 (SES-1), line 2, column (o).

²³ *Id.* Average of line 2, columns (d) through (h).

1 **Q WHAT IS YOUR RECOMMENDATION WITH RESPECT TO THE PROJECTED TEST**
2 **YEAR O&M EXPENSE FOR THE HVD LINE CLEARING PROGRAM?**

3 A Based on the Company's track record of maintaining consistency in 1) underspending
4 planned amounts, 2) the number of HVD line miles cleared, and 3) the number of crews
5 used to accomplish that goal, I recommend reducing the Company's projected test year
6 HVD Line Clearing O&M by 10%, or \$1.184 million.

7 **Q PLEASE SUMMARIZE YOUR RECOMMENDED O&M EXPENSE ADJUSTMENTS.**

8 A Table JAY-5 presents a summarizes all of my recommended O&M expense
9 adjustments.

TABLE JAY-5		
Summary of O&M Expense Disallowances (\$000)		
Line	Description	Amount
		(1)
	Non-Forestry Reliability	
1	LVD Lines Reliability	\$ 7,411
2	HVD Lines Reliability	776
3	LVD Substations Reliability	1,816
	O&M w/o Service Restoration	
4	HVD Lines Demand	2,037
5	LVD Substations Demand	1,991
6	HVD Substations Demand	1,147
7	Staking	7,469
8	Meter Services	5,474
	Field Operations	
9	Training	4,793
	Forestry	
10	HVD Line Clearing	<u>1,184</u>
11	Total	\$ 34,098

III. CAPITAL EXPENDITURES AND RATE BASE

Q PLEASE SUMMARIZE CONSUMERS' PROPOSED LEVEL OF CAPITAL EXPENDITURES ADDED TO RATE BASE.

A As shown on Exhibit A-11 (PDD-30), Schedule A-3, Consumers proposes a rate base level of \$15.368 billion for the projected test year. This represents an increase of about \$1.126 billion, or 7.9%, relative to the historical 2024 test year level of \$14.241 billion. The increase in rate base is primarily driven by \$3.949 billion²⁴ of new capital expenditures proposed by Consumers during the 28-month period ending April 30, 2027.

Q HAVE YOU IDENTIFIED SPECIFIC AREAS WHERE CAPITAL EXPENDITURES CAN BE REDUCED?

A Yes. I have reviewed Consumers' forecasted capital expenditures by major department or functional area and have identified adjustments that would result in expenditure levels that are more reasonable than those proposed by Consumers. These adjustments are summarized in Table JAY-6 and are described below in greater in detail.

²⁴Exhibit A-12 (PDD-35), Schedule B-5, line 12, sum of columns (f) and (g).

TABLE JAY-6				
<u>ABATE Recommended Capital Expenditure Disallowances</u>				
(\$ Millions)				
Line	Description	Bridge Period	Test Year	Total
		(1)	(2)	(3)
Generation				
	LTSA Extra Work			
1	Covert	\$ 21.163	\$ 13.618	\$ 34.781
2	Zeeland	4.703	0.810	5.513
3	Jackson	2.115	0.315	2.430
Distribution				
4	LVD Asset Relocations	\$ 46.409	\$ 27.587	\$ 73.996
5	LVD Lines Rehab	2.975	5.078	8.053
6	LVD New Business Capacity	11.958	3.908	15.866
7	LVD Transformers	105.077	84.896	189.973
8	HVD Strategic Customers New Business	4.340	-	4.340
9	ROW Acquisition	12.667	11.000	23.667
10	Total	\$211.408	\$147.212	\$358.619

1 **Q WHAT IS THE ESTIMATED REVENUE REQUIREMENT IMPACT OF YOUR**
2 **RECOMMENDED CAPITAL EXPENDITURE ADJUSTMENTS?**

3 A The estimated impact on rate base is a reduction of \$130.697 million. Multiplying this
4 by Consumers' proposed pre-tax rate of return of 7.85%²⁵ produces a revenue
5 requirement impact of \$10.255 million. Combined with the estimated impact on
6 depreciation expense and property taxes, the estimated revenue requirement impact
7 is a reduction of \$19.150 million. At ABATE's proposed pre-tax rate of return, I estimate
8 the revenue requirement impact of my capital expenditure adjustments to be about
9 \$18.515 million.

²⁵ Rate of Return Summary, tab BD1 of Company workpaper model A-1 (PDD-1), Sch A-1 to A-13 (PDD-50), Sch C-13, WP-PDD-1-5.xlsx.

1 **Q PLEASE EXPLAIN WHY REDUCING CONSUMERS' PROJECTED CAPITAL**
2 **EXPENDITURES BY \$358.619 MILLION RESULTS IN A \$130.697 MILLION**
3 **REDUCTION TO TOTAL RATE BASE.**

4 A Rate base primarily consists of utility plant-in-service, offset by accumulated
5 depreciation. The Company's projected plant-in-service for the test year was
6 calculated as the 13-month average of utility plant-in-service from April 2026 through
7 April 2027.²⁶ However, I have approximated the impact of my recommended capital
8 expenditure adjustments based on a simple average approach, including the impact of
9 accumulated depreciation. Note, however, that the exact impact would depend on the
10 timing of when the various projects are placed into service. In addition, modifications
11 to the Company's capital expenditures will necessitate adjustments to depreciation
12 expense and property taxes, which I have approximated based on ratios derived from
13 Consumers' class cost of service study.

14 **III.A. Generation Capital Expenditures**

15 **Q WHAT LEVEL OF CAPITAL EXPENDITURES HAS CONSUMERS PROPOSED FOR**
16 **ITS TOTAL GENERATION OPERATIONS?**

17 A As shown on Exhibit A-12 (PDD-35), Schedule B-5, Consumers proposes generation
18 capital expenditures amounts of \$275.408 million during the Bridge Period and
19 \$188.638 million in the projected test year. This is an increase in capital expenditures
20 of about \$464.045 million²⁷ between the historical year and the projected test year.

²⁶ Consumers' workpaper labeled WP-PDD-21. See Exhibit AB-3 at 1.

²⁷ Exhibit A-12 (PDD-35), Schedule B-5, line 3, sum of columns (f) and (g).

III.A.i. Covert Plant

**Q PLEASE IDENTIFY THE EXPENDITURES FOR WHICH YOU RECOMMEND
DISALLOWANCES.**

A I recommend disallowances for the following projects associated with the Covert plant:

Bridge Period

- Units 2 and 3 Long-Term Service Agreement (“LTSA”) Extra Work (\$21.163 million).

Test Year

- Units 1 and 3 LTSA Extra Work (\$13.618 million)

**Q PLEASE DISCUSS THE PROPOSED CAPITAL EXPENDITURES FOR THE
COVERT CAPITAL EXTRAS NOT INCLUDED IN THE LTSA.**

A Consumers proposes to include \$21.163 million in the Bridge Period for work that is not covered under normal planned maintenance in the Covert Plant LTSA.²⁸ In addition, the Company proposes to include in the Test Year capital expenditures of \$9.525 million for Unit 1 and \$4.093 million for Unit 3, all of which are for extra work not covered under normal planned maintenance in the LTSA.²⁹ In summary, Mr. Blumenstock’s testimony indicates that, based on historical outage experience, there are typical items discovered that are not covered under the LTSA, but which need to be addressed.³⁰

²⁸ Direct Testimony of Richard Blumenstock at 62-63.

²⁹ *Id.* at 67-68.

³⁰ *Id.* at 62-63, and 67-68.

1 **Q DO YOU AGREE WITH INCLUDING IN RATES THE PROJECTED CAPITAL**
2 **EXPENDITURES ASSOCIATED WITH EXTRAS NOT INCLUDED IN THE LTSA?**

3 A No. While Mr. Blumenstock provided more detail about the types of issues that might
4 occur and would be covered by this category of investment in the instant case relative
5 to prior cases, the projections are still speculative, may or may not be incurred, and are
6 out of line with historical actuals. Regarding historical actuals, Mr. Blumenstock's
7 workpapers (WP-RTB-17 and WP-RTB-18)³¹ show actual costs in 2023 of \$86,688 and
8 in 2024 of \$1,339,561 for this spending category.

9 Because 1) this category of cost is associated with issues that *might* be
10 discovered that are not covered under the LTSA and 2) historical annual amounts vary
11 significantly from year-to-year with no clear trend, I believe it is premature to include
12 them in rates at this time.

13 Therefore, I recommend the Commission disallow Consumers' projected
14 Bridge Period and Test Year capital expenditures for extra work not covered by the
15 LTSA from recovery through customer rates at this time. A disallowance would be
16 consistent with the Commission's findings in Consumers' prior electric rate cases.³²

³¹ See Exhibit AB-3 at 22-59.

³² Case No. U-21389, Order dated March 1, 2024 at pages 55-56 and Case No. U-21585, Order dated March 21, 2025 at page 149.

III.A.ii. Zeeland

Q ARE THERE PROJECTS AT THE ZEELAND PLANT FOR WHICH YOU RECOMMEND DISALLOWANCES?

A Yes. I recommend disallowances for the following projects associated with Zeeland:

Bridge Period

- Zeeland Plant LTSA Supplementals Not Included in Contract (\$4.703 million).

Test Year

- Zeeland Plant LTSA Supplementals Not Included in Contract (\$0.810 million).

Q PLEASE DISCUSS THE ZEELAND LTSA EXTRAS NOT INCLUDED IN THE CONTRACT.

A Consumers proposes to include \$4.703 million of capital expenditures in the Bridge Period and \$0.810 million in the Test Year for work that is not covered under normal planned maintenance in the LTSA. Mr. Blumenstock's testimony indicates that, based on historical outage experience, there are typical items discovered that are not covered under the LTSA, but which need to be addressed.³³

Q DO YOU AGREE WITH INCLUDING IN RATES THE PROJECTED CAPITAL EXPENDITURES ASSOCIATED WITH EXTRAS NOT INCLUDED IN THE LTSA FOR ZEELAND?

A No. These are speculative projections associated with issues that *might* be discovered during the bridge period and projected test year, based on Consumers' past experience. However, the projected costs are significantly out of line with historical

³³ Direct Testimony of Richard Blumenstock at page 80 and 83.

actuals. Specifically, Mr. Blumenstock's workpapers WP-RTB-15 through WP-RTB-18 provide actual historical costs that fall into this category.³⁴ In 2021 and 2022, the actual cost was approximately \$0.5 million. In 2024, the actual cost was negative \$191,534. In 2023, the actual cost was \$15.2 million.

Thus, there is no clear trend in the capital expenditures associated with this category, and the amounts proposed by Consumers for inclusion in rates are highly speculative and may or may not be incurred. Therefore, I recommend the Commission disallow Consumers' total proposed capital expenditures for this extra work not included in the LTSA from recovery through customer rates at this time.

III.A.iii. Jackson

Q ARE THERE PROJECTS AT THE JACKSON PLANT FOR WHICH YOU RECOMMEND DISALLOWANCES?

A Yes. I recommend disallowances for the following projects associated with Jackson:

Bridge Period

- Jackson Plant LTSA Extra Work (\$2.115 million).

Test Year

- Jackson Plant LTSA Extra Work (\$0.315 million).

Q PLEASE DISCUSS THE JACKSON LTSA EXTRAS NOT INCLUDED IN THE CONTRACT.

A Consumers proposes to include \$2.115 million of capital expenditures in the Bridge Period and \$0.315 million in the Test Year for work that is not covered under normal

³⁴ See Exhibit AB-3 at 2-59.

planned maintenance in the LTSA.³⁵ Mr. Blumenstock's testimony indicates that, based on historical outage experience, there are typical items discovered that are not of the LTSA planned maintenance scope.³⁶

Q DO YOU AGREE WITH INCLUDING IN RATES THE PROJECTED CAPITAL EXPENDITURES ASSOCIATED WITH EXTRAS NOT INCLUDED IN THE LTSA FOR JACKSON?

A No. Similar to Covert and Zeeland, these are speculative projections associated with issues that *might* be discovered during the bridge period and projected test year, based on Consumers' past experience. However, the projected costs are significantly out of line with historical actuals. Specifically, Mr. Blumenstock's workpapers WP-RTB-15 through WP-RTB-18 provide actual historical costs that fall into this category.³⁷ In 2021, the actual cost was \$4.2 million. In 2022, the actual cost was negative \$180,921. In 2023 and 2024, the actual cost was less than \$0.5 million.

Thus, there is no clear trend in the capital expenditures associated with this category, and the amounts proposed by Consumers for inclusion in rates are highly speculative and may or may not be incurred. Therefore, I recommend the Commission disallow Consumers' total proposed capital expenditures for this extra work not included in the LTSA from recovery through customer rates at this time.

³⁵ Direct Testimony of Richard Blumenstock at 84 and 88.

³⁶ *Id.*

³⁷ See Exhibit AB-3 at 2-59.

III.B. Distribution Capital Expenditures

Q WHAT LEVEL OF CAPITAL EXPENDITURES HAS CONSUMERS PROPOSED FOR ITS TOTAL DISTRIBUTION OPERATIONS?

A As shown on Exhibit A-12 (PDD-35), Schedule B-5, Consumers proposes distribution capital expenditure amounts of \$1.598 billion during the Bridge Period and \$1.530 billion in the projected test year. This represents total capital expenditures of \$3.128 billion.³⁸ The majority of the projected distribution capital expenditures are associated with New Business, Reliability, and Demand Failures.³⁹

Q ARE YOU RECOMMENDING ANY ADJUSTMENTS TO CONSUMERS' PROPOSED DISTRIBUTION CAPITAL EXPENDITURES?

A Yes. I recommend adjustments for the following subcategories of distribution projects:

- LVD Lines Rehabilitation
- LVD New Business Capacity
- LVD Transformers
- LVD Asset Relocations
- HVD Strategic Customers New Business
- HVD Lines Reliability (ROW Acquisition)

³⁸ Exhibit A-12 (PDD-35), Schedule B-5, line 1, sum of columns (f) and (g).

³⁹ Exhibit A-12 (MPK-1), Schedule B-5.7.

Q PLEASE EXPLAIN YOUR RECOMMENDED ADJUSTMENT TO THE PROPOSED BRIDGE PERIOD AND TEST YEAR CAPITAL EXPENDITURES FOR THE LVD LINES REHABILITATION CATEGORY.

A This category includes two subprograms for which specific projects cannot be identified, namely, the Modem Replacement Program and Meter Voltage Anomalies. The Company explains that it only creates orders for specific modems close to the time that they are replaced, so there are no specific projects listed for this investment category, and projected spending is based on an assumption of the same volume of work going forward.⁴⁰ Similarly, the Company does not have specific projects identified for the Meter Voltage Anomalies subprogram and does not identify such projects until closer to the time of project execution.⁴¹

Because these two subprograms account for about 37%⁴² and 54%⁴³ of the projected Bridge Period and Test Year LVD Lines Rehabilitation spending, respectively, and the Company does not have specific projects identified at this time for these subprograms, I recommend that the projected Bridge Period and Test Year capital expenditures for the entire LVD Lines Rehabilitation category remain at the five-year average level shown on Exhibit A-113 (MPK-3), line 17. This adjustment removes \$2.975 million from the Bridge Period and \$5.078 million from the Test Year.

⁴⁰ Direct Testimony of Jennifer Partlan at 88.

⁴¹ *Id.*

⁴² Derived from Jennifer Partlan's Direct Testimony, Figure 42 on page 87.

⁴³ *Id.*

Q PLEASE EXPLAIN YOUR RECOMMENDED ADJUSTMENT TO THE PROPOSED BRIDGE PERIOD AND TEST YEAR CAPITAL EXPENDITURES FOR THE LVD NEW BUSINESS CAPACITY CATEGORY.

A The Company projects \$38.180 million of investment in the Bridge Period and \$30.130 million in the Test Year for this program.⁴⁴ However, spending in these categories is customer-driven,⁴⁵ and therefore largely uncertain. The Company's Exhibit A-166 (JMP-1), page 36 identifies only \$8.463 million of projects in this category that are expected to occur in the Bridge Period and notes that additional work will be required.⁴⁶ However, the Company acknowledges that it has not identified any specific projects for the Test Year.⁴⁷

Because actual spending in these categories will be driven by customer requests, which are unknown at this time, it would be more reasonable and prudent to limit the projected investment in this category to the five-year average actual spend shown on Exhibit A-113 (MPK-3), line 25 for both the Bridge Period and Test Year. This adjustment removes \$11.958 million from the Bridge Period and \$3.908 million from the Test Year.

Q PLEASE EXPLAIN YOUR RECOMMENDED ADJUSTMENT TO THE PROPOSED BRIDGE PERIOD AND TEST YEAR CAPITAL EXPENDITURES FOR THE LVD TRANSFORMER CATEGORY.

A The Company projects \$227.963 million of investment in the Bridge Period and \$207.782 million in the Test Year for this program.⁴⁸ These projections represent a

⁴⁴ Direct Testimony of Jennifer Partlan at 119-120.

⁴⁵ *Id.* at 120.

⁴⁶ *Id.* at 118-119.

⁴⁷ *Id.* at 118-119.

⁴⁸ *Id.* at 137.

dramatic increase relative to the five-year average annual historical spend of \$60.603 million and the 2024 actual spend of \$122.886 million.⁴⁹ Further, these increases are based on an estimated number of transformers needed, based on historical data, and expectations about the future.⁵⁰ The Company states that it is planning for continued significant increases in purchases of padmount transformers tied to increased ungrounding work for both new service connections, general new business work, the need to support customers adopting electric vehicles, and ensuring it has restocked its inventory.⁵¹

There is significant uncertainty around investment tied to new business and electric vehicle adoption. In addition, a desire to restock inventory does not mean transformers will become used and useful to customers during the Bridge Period and Test Year. Therefore, I believe a more reasonable and prudent approach to projecting capital expenditures for LVD Transformers would be to use 2024 actual capital expenditure amounts as the projection for both the Bridge Period and Test Year. This approach captures the significant increase in spend that occurred in 2024 relative to prior years but also recognizes the uncertainty I have described. This recommendation reduces the Company's projected capital expenditures by \$105.077 million and \$84.896 million for the Bridge Period and Test Year, respectively.

⁴⁹ Exhibit A-113 (MPK-3), line 5.

⁵⁰ Direct Testimony of Jennifer Partlan at 137.

⁵¹ *Id.* at 137-138.

1 **Q PLEASE EXPLAIN YOUR RECOMMENDED ADJUSTMENT TO THE PROPOSED**
2 **BRIDGE PERIOD AND TEST YEAR CAPITAL EXPENDITURES FOR THE LVD**
3 **ASSET RELOCATIONS CATEGORY.**

4 A The Company projects \$97.911 million of investment in the Bridge Period and \$79.090
5 million in the Test Year for this program.⁵² These projections represent a dramatic
6 increase relative to the five-year average annual historical spend of \$44.604 million and
7 the 2024 actual spend of \$51.502 million.⁵³ Consumers has identified specific projects
8 which account for about \$7 million of the projected spend in the Bridge Period and in
9 the Test Year.⁵⁴ The remainder is highly uncertain, as it is entirely driven by requests
10 from external stakeholders.⁵⁵ Further, the Company explained that customer
11 requested relocations are commonly associated with home remodeling work, which
12 slowed as interest rates rose at the end of 2023.⁵⁶

13 Given the uncertainty surrounding the level of external stakeholder requests
14 that will occur in the Bridge Period and Test Year, I recommend setting the projected
15 capital expenditures for this program in each of these periods equal to the actual level
16 experienced in 2024. This reduces the Company's projected capital expenditures by
17 \$46.409 million and \$27.587 million in the Bridge Period and Test Year, respectively.

⁵² *Id.* at 35.

⁵³ Exhibit A-113 (MPK-3), line 38.

⁵⁴ Direct Testimony of Jennifer Partlan at 35.

⁵⁵ *Id.* at 32.

⁵⁶ *Id.* at 37.

1 **Q WHAT IS YOUR RECOMMENDATION REGARDING THE PROPOSED BRIDGE**
2 **PERIOD AND TEST YEAR CAPITAL EXPENDITURES FOR THE HVD STRATEGIC**
3 **CUSTOMERS NEW BUSINESS CATEGORY?**

4 A This category of projected capital expenditures includes \$4.340 million⁵⁷ in the Bridge
5 Period associated with a customer whose contract was terminated after the customer's
6 postponement of construction continued for more than 12 months.⁵⁸ The Company
7 requests recovery of the Bridge Period expenditures it has already made in good faith,
8 and states that if and when the Company recovers these costs from the customer, that
9 money will be credited to this subprogram and netted back out of rate base.⁵⁹

10 I recommend removing this amount from the Company's projected capital
11 expenditures, rather than recovering it from other customers now and crediting rate
12 base in the future.

13 **Q WHAT IS YOUR RECOMMENDATION REGARDING THE COMPANY'S**
14 **PROJECTED CAPITAL EXPENDITURES FOR ROW ACQUISITION?**

15 A The Company projects capital expenditures of \$12.667 million in the Bridge Period and
16 \$11 million in the Test Year for ROW Acquisition.⁶⁰ The Company's testimony states
17 that it *may* need to acquire new rights of way or expand existing ones during these
18 periods.⁶¹ The Company's investment estimate is based on the most recent actual
19 ROW costs for an executed project.⁶² However, the Company's testimony does not
20 provide actual historical data for ROW Acquisitions or details associated with the "most

⁵⁷ Exhibit A-109 (MLH-3), page 11, line 2.

⁵⁸ Direct Testimony of Megan Hayward at 140.

⁵⁹ *Id.*

⁶⁰ *Id.* at 49.

⁶¹ *Id.* at 47.

⁶² *Id.* at 48.

recent actual ROW costs for an executed project.” Thus, I recommend that these capital expenditures not be allowed for recovery in customer rates at this time.

IV. IMPACT OF REVENUE REQUIREMENT ADJUSTMENTS

Q PLEASE IDENTIFY THE TOTAL REVENUE REQUIREMENT IMPACT OF ALL OF YOUR RECOMMENDED ADJUSTMENTS.

A In total, I recommend a minimum reduction of \$53.248 million to Consumers’ claimed revenue deficiency, based on the Company’s requested 10.25% ROE. However, at Mr. Walters’ recommended ROE of 9.5%, my adjustments would reduce the Company’s claimed revenue deficiency by \$52.613 million. This result is summarized in Table JAY-7.

TABLE JAY-7			
Summary of Revenue Requirement Adjustments (\$ Millions)			
Line	Description	Consumers ROE (1)	ABATE ROE (2)
1	Capital Expenditures*	\$ 19.150	\$ 18.515
2	O&M Expenses	34.098	34.098
3	Total Adjustments	\$ 53.248	\$ 52.613
* Includes estimated impact on rate base, depreciation, and property taxes.			

Q DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A Yes, it does.

Qualifications of Jessica A. York

1 **Q PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.**

2 A Jessica York. My business address is 16690 Swingley Ridge Road, Suite 140,
3 Chesterfield, MO 63017.

4 **Q PLEASE STATE YOUR OCCUPATION.**

5 A I am a consultant in the field of public utility regulation and a Principal with the firm of
6 Brubaker & Associates, Inc. ("BAI"), energy, economic and regulatory consultants.

7 **Q PLEASE IDENTIFY THE JURISDICTIONS IN WHICH YOU HAVE PREVIOUSLY**
8 **SPONSORED TESTIMONY.**

9 A I have sponsored expert testimony in front of the Idaho Public Utilities Commission, the
10 Illinois Commerce Commission, Indiana Utility Regulatory Commission, the Iowa
11 Utilities Commission, the Kansas Corporation Commission, the Kentucky Public
12 Service Commission, the Michigan Public Service Commission, the Minnesota Public
13 Utilities Commission, the Missouri Public Service Commission, the Public Utilities
14 Commission of Nevada, the Oklahoma Corporation Commission, the Virginia State
15 Corporation Commission, and the Public Service Commission of Wisconsin.

16 **Q PLEASE STATE YOUR EDUCATIONAL BACKGROUND AND PROFESSIONAL**
17 **EMPLOYMENT EXPERIENCE.**

18 A I graduated from Truman State University in 2008 where I received my Bachelor of
19 Science Degree in Mathematics with minors in Statistics and Actuarial Science. I
20 earned my Master of Business Administration Degree with a concentration in Finance
21 from the University of Missouri-St. Louis in 2014.

1 I joined BAI in 2011 as an analyst. Then, in March 2015, I joined the consulting
2 team of BAI.

3 I have worked in various electric, natural gas and water and wastewater
4 regulatory proceedings addressing cost of capital, sales revenue forecasts, revenue
5 requirement assessments, class cost of service studies, rate design, and various policy
6 issues. I have also conducted competitive power and natural gas solicitations on behalf
7 of large electric and natural gas users, have assisted those large power and natural
8 gas users in developing procurement plans and strategies, assisted in competitive
9 contract negotiations, and power and natural gas contract supply administration. In the
10 regulated arena, I have evaluated cost of service studies and rate designs proffered by
11 other parties in cases for various utilities, including in Idaho, Illinois, Indiana, Kansas,
12 Wisconsin and others. I have conducted bill audits, rate forecasts and tariff rate
13 optimization studies.

14 I have also provided support to clients with facilities in deregulated markets,
15 including drafting supply requests for proposals, evaluating supply bids, and auditing
16 competitive supply bills. I have also prepared and presented to clients reports that
17 monitor the electric market and recommend strategic hedging transactions.

18 BAI was formed in April 1995. BAI and its predecessor firm have participated
19 in more than 700 regulatory proceedings in forty states and Canada.

20 BAI provides consulting services in the economic, technical, accounting, and
21 financial aspects of public utility rates and in the acquisition of utility and energy
22 services through RFPs and negotiations, in both regulated and unregulated markets.
23 Our clients include large industrial and institutional customers, some utilities and, on
24 occasion, state regulatory agencies. We also prepare special studies and reports,
25 forecasts, surveys and siting studies, and present seminars on utility-related issues.

1 In general, we are engaged in energy and regulatory consulting, economic
2 analysis and contract negotiation.

3 In addition to our main office in St. Louis, the firm also has branch offices in
4 Corpus Christi, Texas; Louisville, Kentucky and Phoenix, Arizona.

1 MR. CAMPBELL: Thank you, Your Honor.

2 Mr. Fitzhenry's pre-filed direct testimony
3 consists of a cover page, a table of contents, 29 pages of
4 questions and answers, and an appendix A setting up his
5 qualifications, and along with his pre-file direct
6 testimony, Mr. Fitzhenry sponsored an Exhibit AB-4, and
7 Mr. Fitzhenry did not file any rebuttal testimony.

8 JUDGE THOITS: Are there any objections to the
9 admission of this testimony or this exhibit?

10 Hearing none. The direct testimony of Colin
11 Fitzhenry is bound into the record, and Exhibit AB-4 is
12 admitted.

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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 generation and distribution of)
 electricity and for other relief.)

Case No. U-21870

Direct Testimony and Exhibits of

Colin T. Fitzhenry

On behalf of

Association of Businesses Advocating Tariff Equity

September 30, 2025



Project 11862

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) Case No. U-21870
the generation and distribution of)
electricity and for other relief.)
_____)

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Direct Testimony of Colin T. Fitzhenry

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Appendix A: Qualifications of Colin T. Fitzhenry

Exhibit AB-4: 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) Case No. U-21870
the generation and distribution of)
electricity and for other relief.)
_____)

Direct Testimony of Colin T. Fitzhenry

I. INTRODUCTION

1

2 Q PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

3 A Colin T. Fitzhenry. My business address is 16690 Swingley Ridge Road, Suite 140,
4 Chesterfield, MO 63017.

5 Q WHAT IS YOUR OCCUPATION?

6 A I am a consultant in the field of public utility regulation and an Associate with the firm
7 of Brubaker & Associates, Inc. ("BAI"), energy, economic and regulatory consultants.

8 Q PLEASE DESCRIBE YOUR EDUCATIONAL BACKGROUND AND EXPERIENCE.

9 A This information is included in Appendix A to my testimony.

10 Q ON WHOSE BEHALF ARE YOU APPEARING IN THIS PROCEEDING?

11 A I am appearing on behalf of the Association of Businesses Advocating Tariff
12 Equity ("ABATE"). ABATE consists of large usage customers that purchase substantial
13 amounts of electric power and/or delivery service from Consumers Energy

Company ("Consumers" or "Company"). They primarily take service under Consumers' Rate GPD, Rate GPTU, Rate EIP, Rate GP, Rate GSG-2 and/or Rate LTILRR.

Q WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A The purpose of my testimony is to address the Company's current electric service reliability and the Company's proposed distribution capital expenditures. Specifically, I recommend adjustments to Investment Recovery Mechanism ("IRM") capital expenditures for Low Voltage Distribution ("LVD") Pole Replacements and LVD Targeted Circuit Improvement. Additionally, I recommend adjustments to base rate capital expenditures for Overhead to Underground Conversions, Line Regulator Controller Upgrades, High Voltage Distribution ("HVD") Lines Reliability, HVD Substations Reliability, and a 138 kV Dedicated Customer Substation.

My silence in this testimony, or that of my colleagues in their own testimonies, with regard to any issue should not be construed as an endorsement of Consumers' position on that issue.

Q PLEASE BRIEFLY SUMMARIZE YOUR CONCLUSIONS AND RECOMMENDATIONS IN THIS PROCEEDING.

A My conclusions and recommendations are as follows:

1. The Company's claim of improving reliability is based on a "cherry-picked" view of its data, selectively focusing on a metric that excludes major weather events. A broader comparison shows that Consumers consistently ranks at the bottom among peer utilities in neighboring states, with the average Consumers customer experiencing 339 more minutes of outages per year. This poor reliability performance has occurred despite a significant increase in capital spending. From 2020 to 2024, the Company's annual distribution capital expenditures increased by 49%, or \$287 million, without any meaningful reduction in customer outage minutes. To address this, the Commission should require the Company to demonstrate a clear link between its investments and quantifiable reliability improvements before approving any further rate increases.

2. I recommend adopting a 5% rejection rate for the LVD pole replacement program. This is a more realistic estimate based on utility comparisons. Using this rate would reduce capital expenses for pole replacement by 50%, resulting in an authorized IRM capital expenditure reduction of \$63,750,000 in the test year and year after.
3. I recommend denying the request for additional authorized capital expenditures for vintage underground cable rejuvenation in the test year, as it does not provide immediate safety or reliability benefits and is more of a preventative maintenance project, which is not appropriate for cost recovery through the IRM. This would reduce the proposed authorized IRM capital expenditures by \$45,057,250 in the test year and year after.
4. The proposed large-scale overhead to underground conversion program should be rejected entirely. The Company has not provided sufficient justification for the expansion past its pilot program, as its own data shows it is the most expensive option under the utility cost test. The Company has also shown a lack of ability to efficiently execute the program, citing significant real-world challenges with securing easements during the pilot phase. This recommendation would reduce projected test year capital expenditures by approximately \$20,000,000.
5. For the line regulator controller project, I recommend reducing the proposed pace to 25% of the planned installation rate. I am concerned about the Company's benefit-cost analysis, noting it excludes key costs such as taxes, Return on Equity, interest, and potential stranded costs, which are ultimately borne by customers. The analysis also makes an unreasonable assumption that all line regulators installed before the year 2000 will fail in the next ten years, which lacks supporting evidence. This reduction would decrease projected capital expenditures for this project by \$7,894,500 for the bridge period and \$3,840,000 for the test year.
6. I also recommend that the Company maintain current investment levels for the HVD Lines Reliability and HVD Substations Reliability programs. The Company's recent outage data does not support a need for increased investment in the HVD system, as almost all outages over the last three years were the result of a fault in the LVD system. This would reduce projected capital expenditures: by \$90,648,903 for the bridge period and \$75,403,427 for the test year for the HVD Lines Reliability program; and by \$39,711,365 for the bridge period and \$33,964,524 for the test year for the HVD Substations Reliability program.
7. Lastly, I recommend that the \$20.619 million in test year expenditures for a 138 kV dedicated customer substation be removed from the rate base because the project was canceled. Since the project was never completed and was designed for a single customer, it is not considered "used and useful." I recommend that the Company seek to recover any sunk costs from the customer who canceled the project.

My specific recommendations, which are based on the Company's historical lack of efficacy in past investment decisions result in the following reductions in the Company's proposed base rate revenue requirement and IRM expense:

- The proposed adjustments to the LVD Pole Replacements and LVD Targeted Circuit Improvement project reduce the Company's proposed authorized IRM capital expenditures by approximately \$108.8 million in the test year and the year after.
 - These two adjustments reduce the Company's IRM surcharge revenue requirement in the projected test year by \$5.781 million.
- Additional adjustments to Overhead for Underground Conversions, Line Regulator Controller Upgrades, HVD Lines Reliability, HVD Substations Reliability, and a 138 kV Dedicated Customer Substation reduce capital expenditures by approximately \$138.3 million and \$153.4 million for the bridge period and test year, respectively.
- These five adjustments reduce the Company's base rate revenue requirement by \$22.9 million, based on the Company's requested 10.25% ROE. However, at Mr. Walters' recommended ROE of 9.5%, my adjustments would reduce the Company's claimed revenue deficiency by \$22.0 million.

II. ELECTRIC SERVICE RELIABILITY

Q PLEASE BRIEFLY DESCRIBE THE COMPANY'S CURRENT ELECTRIC SERVICE RELIABILITY.

A The Company measures electric service reliability using several reliability metrics, most prominently the System Average Interruption Duration Index ("SAIDI"). Other metrics include System Average Interruption Frequency Index ("SAIFI"), Customer Average Interruption Duration Index ("CAIDI"), and Customers Experiencing Multiple Interruptions ("CEMI"). Based on the Company's data from 2015-2024, the SAIDI performance, excluding Major Event Days ("MEDs"), was 155 minutes in 2024, which was better than the projected 170 minutes.¹ According to the Company, this

¹ Kelly Direct at 29.

performance indicates that the Company's reliability investments are producing results.² However, in its audit report, Liberty Consulting Group assessed the Company's historical SAIDI performance and concluded that reliability had not improved over the past decade, despite increases in total capital and O&M expenditures.³ The Company aims to improve its reliability performance and reach a SAIDI performance of approximately 128 minutes, excluding MEDs, by 2029.⁴ According to Consumers, this would place the Company in the second quartile or better among peer utilities, demonstrating better than average reliability performance.⁵

Q HOW DOES THE COMPANY'S RECENT ELECTRIC SERVICE RELIABILITY METRICS COMPARE TO PEER UTILITIES?

A In the 2024 Liberty audit, it was noted that the Company's SAIDI and CAIDI metrics for 2022 and 2023 were in the 4th quartile, including MEDs, and the 3rd quartile, excluding MEDs.⁶ In order to clarify the specifics of Consumers' reliability metrics within its regional context, I have prepared an analysis to include 2024 data from EIA-861, Annual Electric Power Industry Report. In my analysis, I compared the Company's SAIDI with MEDs (All Days) and SAIDI without MEDs (No MEDs) to other investor owned utilities in Michigan and states sharing a land border with Michigan (Ohio, Indiana, and Wisconsin) for the period 2020-2024. The purpose of reducing the scope of the reliability comparison analysis to only include neighboring states is so the utilities included in the analysis share a similar geographic region and are thus impacted by similar weather patterns. This data is shown in Table CTF-1 below.

² Kelly Direct at 25.

³ Final Report Utility Distribution Audit of Consumers Energy, Part One, September 23, 2024, Page 71.

⁴ Kelly Direct at 22.

⁵ *Id.*

⁶ Kelly Direct at 26.

Table CTF-1												
<u>Investor Owned Utility Historical Reliability Performance (SAIDI IEEE Standard)</u>												
Line	Utility	State	2020		2021		2022		2023		2024	
			All Days	No MEDS	All Days	No MEDS	All Days	No MEDS	All Days	No MEDS	All Days	No MEDS
1	Duke Energy Ohio Inc	OH	211.9	106.4	144.3	124.9	541.2	113.3	168.2	103.6	321.1	102.5
2	Consumers Energy Co	MI	510.3	194.7	911.2	227.9	466.6	182.0	913.0	176.4	502.6	155.0
3	Dayton Power & Light Co	OH	174.3	122.3	179.6	108.0	182.0	108.9	170.5	96.2	502.6	106.4
4	DTE Electric Company	MI	351.8	141.9	927.4	135.6	583.9	146.2	1542.3	156.8	483.0	159.2
5	AES Indiana	IN	154.7	73.4	176.4	104.4	147.3	112.5	466.8	86.7	246.9	87.3
6	Indiana Michigan Power Co	IN	300.3	154.1	426.2	148.4	389.3	120.7	155.1	94.6	156.7	97.5
7	Indiana Michigan Power Co	MI	300.3	154.1	426.2	148.4	389.3	120.7	155.1	94.6	156.7	97.5
8	Madison Gas & Electric Co	WI	27.3	22.4	39.6	31.9	110.3	22.3	64.0	23.5	278.6	41.6
9	Northern States Power Co	MI	346.0	244.0	562.2	177.0	391.1	211.8	245.2	163.5	166.3	115.5
10	Northern States Power Co	WI	346.0	244.0	562.2	177.0	391.1	211.8	245.2	163.5	166.3	115.5
11	Ohio Power Co	OH	254.6	166.8	231.0	171.4	595.3	179.4	326.1	147.6	272.2	158.1
12	Superior Water and Light Co	WI	55.7	39.6	82.3	21.4	99.6	35.7	86.1	17.0	22.4	7.2
13	The Toledo Edison Co	OH	102.8	66.8	167.0	68.6	165.6	95.4	331.4	79.9	121.0	95.4
14	Upper Peninsula Power Company	MI	292.9	206.2	273.4	148.7	566.8	204.6	425.1	140.6	404.3	186.8
15	Wisconsin Electric Power Co	WI	140.0	94.0	417.0	102.0	279.0	121.0	272.0	85.0	296.0	109.0
16	Wisconsin Public Service Corp	WI	104.0	104.0	555.0	95.0	462.0	96.0	150.0	74.0	465.0	95.0
17	Upper Michigan Energy Resources	MI	253.0	222.0	779.0	239.0	799.0	286.0	365.0	187.0	1082.0	218.0
18	Consumers Rank		17	13	16	16	12	13	16	16	15	13
19	Average w/o Consumers		213.5	135.1	371.8	125.1	380.8	136.6	323.0	107.1	321.3	112.0
Source: Form EIA-861, Annual Electric Power Industry Report, 2020-2024												

As can be seen from Table CTF-1, of the 17 utilities represented, Consumers ranks between 12 and 17, depending on the metric and year, with an average rank of about 15 out of 17. This puts Consumers at or near the bottom in terms of reliability performance within its peer utilities over the last five years. In addition, the average SAIDI with MEDs for all utilities for the past five years has been approximately 322 minutes per year, but Consumers' SAIDI with MEDs average has been approximately 661 minutes per year, meaning the average Consumers' customer experienced approximately 339 minutes more of outages per year than the average customer in Michigan, Indiana, Wisconsin, and Ohio served by an Investor Owned Utility.

Q WHAT HAS BEEN THE PRIMARY CAUSE OF OUTAGES HISTORICALLY?

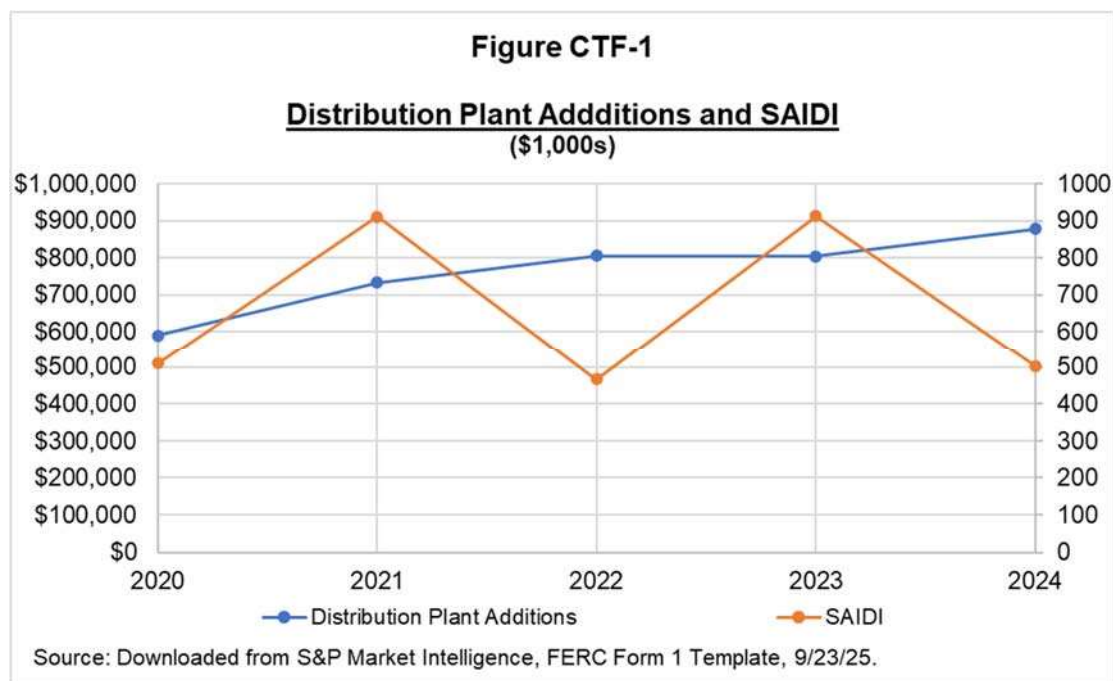
A I have summarized the amounts of customer minutes of power interruption ("CMI") by the outage cause for the last three years (2022-2024) in Table CTF-2 below.

Table CTF-2			
<u>Primary Cause of Outages (2022-2024)</u>			
<u>Line</u>	<u>Outage Cause</u>	Customer Minutes <u>Interrupted</u>	Percent of <u>Total</u>
1	No Specific Cause Found	188,416,635	5%
2	Unique Incident	57,626,749	1%
3	Animal	29,634,390	1%
4	Equipment Failure	358,224,514	9%
5	Trees	1,839,800,787	45%
6	Weather	1,073,280,202	26%
7	Bird	7,097,739	0%
8	Public Damage	21,484,876	1%
9	Public Tree Trimming	3,715,716	0%
10	Lightning	31,731,784	1%
11	Trees - Outside ROW	285,112,117	7%
12	Forced Outage/Emergency	21,042,345	1%
13	Car/Pole Accident	147,201,874	4%
14	Transmission/Generation	16,078,517	0%
15	Total	4,080,448,245	100%
Source: U21870-AB-CE-0700_Kelly_ATT_1.xlsx provided in response to Data Request U21870-AB-CE-0700.			

1 As can be seen from Table CTF-2, customers experienced over 4 billion minutes of
2 outages over the last three years. The majority of outages were the result of trees or
3 trees outside the ROW (52%) and the second leading cause of outages was the
4 result of weather (26%). Meaning that only 22% of outages were the result of other
5 causes such as equipment failures, car/pole accidents, unique incidents, etc. If the
6 Company intends on making any meaningful improvement to its future reliability
7 metrics, then the primary focus should be on vegetation management as opposed to
8 asset replacement since equipment failures only account for a small percentage of
9 total outage minutes.

Q HAS THE COMPANY BEEN ACCELERATING INVESTMENT IN ITS DISTRIBUTION SYSTEM OVER THE PAST FIVE YEARS?

A Yes. I have shown the distribution plant additions and the Company's SAIDI with MEDs over the period 2020-2024 in Figure CTF-1.



As can be seen from Figure CTF-1, the Company's distribution plant additions, or capital expenditures, have increased from approximately \$590 million in 2020 to \$878 million in 2024, an increase of \$287 million or 49% in five years. Meanwhile, there has been no discernable trend in the Company's SAIDI with MEDs metric over the same period. This means that the Company has not been able to reduce customer outage minutes, despite significant increases in the annual distribution capital expenditure levels.

In addition, the Company's investment in its distribution system has had a significant impact on its overall rate base. Consumers' requested rate base of \$15.4 billion in this proceeding is \$3.7 billion more than the rate base approved in Docket No. U-20697 (\$11.7 billion) for the 2021 test year. An increase in a utility's rate base,

usually from investments in new infrastructure, is a primary driver of the utility's revenue requirement, which directly results in higher rates for customers.

Q WHAT CAN YOU CONCLUDE FROM THIS ANALYSIS?

A The facts presented demonstrate a troubling pattern of increasing investment with no corresponding improvement in reliability for customers. The Company's position that its reliability is improving is based on a cherry-picked view of its data, selectively focusing on SAIDI excluding MEDs, while ignoring the more critical all-weather SAIDI metric that reflects the actual experiences of its customers. While the Company claims its SAIDI performance without MEDs is improving, a broader comparison shows that it consistently ranks at the bottom of its peers. The average Consumers customer experiences an unacceptable 339 minutes more of outages per year than the average customer of other electric utilities both within Michigan and in neighboring states.

This poor performance is occurring despite a massive influx of capital. The Company's distribution plant additions have increased by 49%—or \$287 million—over the past five years. This increase in spending has not translated into any meaningful reliability gains for customers. The Company should be directing its investment to focus on the primary cause of outages, as opposed to focusing on capital investments to grow future returns.

The Commission must view this request for further investment with extreme skepticism. Continuing to grant these requests based on the Company's current flawed methodology would be a disservice to customers, forcing them to bear the cost of millions of dollars in new investment, while receiving little tangible benefits in return. Instead of approving more funding, the Commission should demand that the Company first demonstrate a clear link between its investments and quantifiable improvements

1 in reliability before any further rate increases are considered. My recommendations in
2 this proceeding to reduce the Company's proposed distribution capital investments
3 consider the historical lack of efficacy the Company has demonstrated in prior
4 investment decisions.

5 **III. LOW VOLTAGE**
6 **DISTRIBUTION LINES RELIABILITY**

7 **Q PLEASE DESCRIBE THE COMPANY'S LVD LINES RELIABILITY SUBPROGRAM.**

8 A The LVD Lines Reliability Subprogram is a capital program designed to ensure safe
9 and reliable operation of Consumers' LVD lines. It is part of the broader strategy
10 outlined in the Company's Reliability Roadmap, which aims to improve electric service
11 and enhance the grid's resilience against severe weather. The program includes
12 various projects aimed at addressing specific concerns on the LVD system. The LVD
13 Lines Reliability subprogram consists of five investment categories: (1) targeted circuit
14 improvements; (2) pole replacements; (3) ATR loops; (4) circuit exit enhancements;
15 and (5) ROW and easement acquisition.⁷ The Company is proposing that cost related
16 to the two largest investment categories, targeted circuit improvements and pole
17 replacements, be recovered through the Company's IRM. The targeted circuit
18 improvements and pole replacements investment categories will be discussed in
19 greater detail later on in my testimony.

⁷ Partlan Direct at 44.

Q WHAT ARE THE PROJECTED COSTS FOR THE LVD LINES RELIABILITY SUBPROGRAM?

A The projected capital expenditures for the LVD Lines Reliability Subprogram are \$180,763,000 for the 16-month bridge period ending April 30, 2026⁸ and \$312,886,000 for the 12-month test year ending April 30, 2027.⁹ However, the majority of the LVD Lines Reliability Subprogram capital expenditures, \$276,191,000 in the test year, are being proposed for recovery through the IRM surcharge.¹⁰

Q WHAT WAS THE COMMISSION'S DECISION REGARDING THIS PROGRAM IN THE LAST RATE CASE FINAL ORDER (DOCKET NO. U-21585)?

A In the Final Order for Docket No. U-21585, the Commission did not approve all of the Company's proposed expenditures, but it did authorize the Company to move forward with certain investments. The Commission authorized \$86.347 million for Year 2 of IRM, which included \$68.523 million for the LVD Lines Reliability category.¹¹

The Commission adopted the ALJ's recommendation to disallow specific project expenditures within the LVD Lines Reliability category. For the Zonal Health Improvements and Right-of-Way ("ROW") acquisitions, the Commission agreed with the ALJ that the Company's evidence was insufficient. The Commission found that Consumers failed to provide historical cost data for the relabeled "Zonal Health" program and did not adequately justify the significant spending increase.¹² Similarly, for ROW acquisitions, the Commission found that the Company lacked the necessary detail linking projected costs to specific projects.¹³ The Commission also agreed with

⁸ A-166 (JMP-1), Page 14 of 37.

⁹ A-167 (JMP-2), Page 10 of 28.

¹⁰ Kelly Direct at 102, Figure 31, Proposed IRM Expenditures.

¹¹ U-21585 Order at 365.

¹² U-21585 Order at 62.

¹³ U-21585 Order at 64.

1 the Attorney General's disallowance for secondary conversions, finding that the
2 significant ramp-up in spending was not sufficiently supported with details on the
3 benefits to a relatively small number of customers.¹⁴

4 The Commission explicitly stated that future requests for cost recovery in this
5 category must be supported by more complete historical data and a clear justification
6 of how the investments deliver value to customers.¹⁵ Additional details regarding the
7 Commission's decision in U-21585 are discussed in my colleague's testimony, ABATE
8 witness Jim Dauphinais.

9 **IIIA. LVD Pole Replacements**

10 **Q PLEASE DESCRIBE THE COMPANY'S PLAN FOR LVD POLE REPLACEMENTS.**

11 A The Company's plan for LVD pole replacements is to address poles identified as
12 needing replacement through inspections.¹⁶ A new program will conduct groundline
13 inspections on all poles on a 12-year cycle, aiming to inspect 125,000 poles each
14 year.¹⁷ Based on the age and condition of the poles, approximately 10% are expected
15 to be classified as "rejected" and will be replaced.¹⁸ According to the Company, this
16 proactive replacement strategy is considered more economical and safer than waiting
17 for poles to fail. The new standard for LVD primary poles is Class 3, which can
18 withstand wind gusts up to 141 MPH without ice or 71 MPH with half an inch of ice.¹⁹
19 Poles range from Classes 1-6, with lower class poles being able to withstand harsher
20 conditions. The Company has also started a pilot to install ductile iron poles in certain

¹⁴ *Id.*

¹⁵ U-21585 Order at 63.

¹⁶ Partlan Direct at 19.

¹⁷ Partlan Direct at 60.

¹⁸ Partlan Direct at 61.

¹⁹ Partlan Direct at 63.

locations as a more durable alternative to wood poles.²⁰ The Company plans to ramp up LVD pole replacements from 2,300 in 2025 to 12,500 in 2027, which will cost \$127,500,000 in the test year period.²¹

Q DO YOU HAVE ANY CONCERNS ABOUT THE COMPANY'S LVD POLE REPLACEMENT PLAN.

A Yes. The Company has said that it "generally agrees" with Liberty's recommendation to place less emphasis on asset age when deciding whether to replace assets.²² However, when determining the forecasted rejection rate for pole replacements, the Company solely relied on asset age. The Company assumes that (i) all poles with a vintage between 1937-1960 are considered high risk and will have a greater than 15% rejection rate, (ii) poles with a vintage between 1961-1980 are considered moderate risk poles and have a 10%-15% rejection rate, and (iii) poles with a vintage between 1981-2025 are considered minor risk and have less than a 10% rejection rate.²³ By using these assumed rejection rates by pole vintage and then weighting those values based on the average age of the population of distribution poles, the Company arrived at the estimated 10% rejection rate for all poles.

Q HOW SHOULD THE COMPANY FORECAST THE REJECTION RATE FOR POLES?

A The Company should rely on a sample of pole inspections to make a more accurate determination of the appropriate rejection rate. Using a sample of pole inspections is the most practical way to estimate the overall rejection rate of a much larger population

²⁰ *Id.*

²¹ A-167 (JMP-2), Page 6 of 28.

²² Kelly Direct at 22.

²³ Exhibit No. A-129 (MPG-19), page 69.

of poles. A properly selected sample allows for a reliable assessment of the entire population.

Q ABSENT THIS INFORMATION, WHAT IS YOUR RECOMMENDATION?

A I recommend the Company adopt a 5% rejection rate when estimating the number of pole replacements during groundline inspections. This is at the higher end of rejection rates when comparing the actual rejection rates of utilities who have utilized groundline inspections for pole replacement. For example, the rejection rate of Midwest Energy was 4.63% during the first cycle through its distribution system.²⁴ Reducing the rejection rate to 5% reduces the Company's proposed capital expense for pole replacement by 50%. This adjustment reduces the Company's proposed authorized IRM capital expenditures by \$63,750,000 in both the test year period and the year after.

IIIB. LVD Targeted Circuit Improvement

Q PLEASE DESCRIBE THE COMPANY'S PLAN FOR LVD TARGETED CIRCUIT IMPROVEMENT.

A The Company's LVD targeted circuit improvement plan includes several project types within four distinct project categories including: (1) reducing the amount of non-standard voltage on the distribution system; (2) zonal health investments; (3) converting open-wire secondary to multiplex; and (4) rejuvenating vintage underground cable. The proposed test year expenditures for each of these projects include \$33,115,000 for voltage conversion, \$14,224,000 for zonal health, \$14,670,000 for

²⁴ <https://www.mwenergy.com/news/view/pole-inspections-minimize-storm-damage-bring-improved-reliability>

secondary conductors, and \$65,989,000 for underground cable for a combined \$127,998,000 in the LVD Targeted Circuit Improvement category.²⁵

Q DO YOU HAVE ANY CONCERNS ABOUT THE COMPANY'S TARGETED CIRCUIT IMPROVEMENT PLAN?

A Yes. As stated by the Commission, the purpose of the IRM is to address "safety and reliability."²⁶ However, the vintage underground cable rejuvenation project does not provide immediate safety or reliability benefits. Since this involves the replacement of cable that is already located underground, the safety and reliability benefits of undergrounding have already been realized by the Company. Thus, this project is more accurately characterized as preventative maintenance, which would only provide future benefits in the event that an existing underground cable fails. This raises concerns that the Company's plan is not using the IRM as the Commission intended.

Q HAS THE COMPANY FORECASTED THE SAFETY AND RELIABILITY BENEFITS OF REJUVENATING VINTAGE UNDERGROUND CABLE?

A No. The Company did not quantify the benefits of rejuvenating vintage underground cable, despite requesting an additional \$38,080,000 in capital expenditures in the test year above amounts included in the bridge period.

Q WHAT IS YOUR RECOMMENDATION REGARDING THE COMPANY'S LVD TARGETED CIRCUIT IMPROVEMENT?

A I recommend the Commission deny the Company's request for additional capital expense for vintage underground cable rejuvenation in the test year period. Since the

²⁵ A-167 (JMP-2), Multiple Pages.

²⁶ Case No. U-21389 Final Order at 273.

bridge period is 16 months, the average monthly capital expenditures would be \$1,744,312. Applying the monthly capital expenditures to the 12-month test year period would result in an annual expense of \$20,931,750. This adjustment reduces the Company's proposed authorized IRM capital expenditures by \$45,057,250 in both the test year period and the year after.

IV. OVERHEAD TO UNDERGROUND CONVERSIONS

Q PLEASE DESCRIBE THE COMPANY'S OVERHEAD TO UNDERGROUND INVESTMENT PLAN.

A The Company's Overhead to Underground conversion program is an investment category aimed at improving the grid's resiliency and mitigating wildfire risks.²⁷ This initiative involves replacing sections of existing overhead lines with underground lines and their associated equipment. The program, which was initially introduced through a pilot project, is planned to ramp up to 400 miles of undergrounding annually, with a goal of starting projects in the test year and reaching full, annual capacity by 2028.²⁸ Research from other utilities indicates that undergrounding can improve a circuit's performance by 90% or more, by removing its exposure to trees and severe weather events.²⁹ The cost of this work is estimated to be comparable to other methods of hardening the grid, such as installing aerial spacer cable or tree wire.³⁰ While the Liberty audit recommended delaying the plan, the Company has decided to move forward with the program based on the positive results of the pilot, which demonstrated the cost-effectiveness and reliability benefits of undergrounding.³¹ The Company is

²⁷ Exhibit No. A-132 (MPK-22) at 27.

²⁸ Kelly Direct at 67.

²⁹ Partlan Direct at 105.

³⁰ Kelly Direct at 62.

³¹ Kelly at 23.

proposing \$1.25 million in bridge period capital expenses for Overhead to Underground Conversions and \$20 million in the test year.

Q WHY DID LIBERTY RECOMMEND DELAYING IMPLEMENTATION OF THE OVERHEAD TO UNDERGROUND CONVERSION PROGRAM IN ITS AUDIT?

A Liberty recommended delaying the expansion of Consumers' overhead to underground conversion program beyond the initial pilot phase because, at the time of the audit, there were currently not enough grounds to support a full-scale expansion of the program, with Liberty citing significant uncertainties about the actual costs and reliability benefits.³² The report suggested that the major expansion in annual expenditures should be delayed by at least a year or more and could potentially be reduced, based on the lessons learned from the pilot projects.³³ The report notes that, historically, undergrounding has been much more expensive than overhead construction, and that, while it's a good resiliency measure in specific areas, like those with high tropical storm or wildfire exposure, it's not clear it will be beneficial at the levels identified in the Electric Distribution Infrastructure Investment Plan.³⁴ The report also questions whether the reliability improvements from undergrounding are significantly better than those from less costly alternatives, such as accelerated tree trimming.³⁵

³² Final Report Utility Distribution Audit of Consumers Energy, Part Two, September 23, 2024, Page 70.

³³ *Id.*

³⁴ *Id.*

³⁵ Final Report Utility Distribution Audit of Consumers Energy, Part Two, September 23, 2024, Page 71.

**Q HAS THE COMPANY PRESENTED INFORMATION ON THE
COST- EFFECTIVENESS OF THE UNDERGROUNDING PILOT PROGRAM?**

A Yes. Company Witness Michael Kelly discusses the Present Value of the Revenue Requirement ("PVRR") for the undergrounding pilot projects in his direct testimony. According to the Company's own data and using the Utility Cost Test ("UCT"), undergrounding is the most expensive option when compared to Aerial Spacer Cable including Forestry, Tree Wire Including Forestry, and Existing Overhead Including Forestry using the utility cost test ("UCT").³⁶ However, the Company also provides the results of a Societal Cost Test ("SCT"), which demonstrates that Undergrounding is the least cost option.³⁷ The SCT uses a lower discount rate than the UCT, which assigns more value to benefits further out in the investment lifecycle, when the benefits are more speculative.

While I have concerns about the methodology deployed by the Company in both the UCT and SCT, the Company has not demonstrated that Undergrounding is consistently the preferred solution using both cost tests.

**Q DO YOU HAVE ANY ADDITIONAL CONCERNS ABOUT THE COMPANY'S
PROPOSED UNDERGROUNDING PROGRAM?**

A Yes. The Company has acknowledged that the Undergrounding Pilot was not completed as planned due to challenges with securing easements on four of the undergrounding projects that were originally approved in Case No. U-21389. The four projects are as follows:³⁸

- Blue Star-Pier Cove LCP 622: A group of landowners in this area opposed the project as designed, requiring significant design changes and leading the Company to defer the project beyond the period covered by Case No.

³⁶ Kelly Direct at 62, Figure 24.

³⁷ Kelly Direct at 62, Figure 25.

³⁸ Response to Data Request U21870-AB-CE-0702.

U-21389. All easements have since been acquired for this project to move forward.

- Dean Road-Hogan LCP 951: Multiple landowners had concerns with the initially proposed alignment for this project, but the Company has redesigned the project to use the road right of way instead. All easements have since been acquired for this project to move forward.
- Peck Road/M-91 LCP 473: This is an unusually complex project in terms of the number of easements required, and the Company's easement acquisition process has taken longer than expected. The design for this project took longer than expected, which delayed starting easement acquisition.
- Merson-Merson LCP 412: This project involved landowners requesting a number of changes, such as working around septic systems and drain fields. The Company anticipates acquiring these remaining easements in September 2025.

The Company is proposing to scale the size of the undergrounding program from 8.8 miles completed in the Pilot to 400 miles in this proceeding. Since the Company is already having issues completing specific circuits identified for undergrounding, then I expect that problems will only be exacerbated when the program is increased by 45 times its current size. In addition, if the Company changes its proposed projects from one circuit to another due to issues with landowners, the benefits of undergrounding in the alternate circuit may not be as great as the benefits in the originally identified circuit. This would further reduce the cost-effectiveness of the program and lower the benefits shown in the Company's UCT and SCT.

Q WHAT IS YOUR RECOMMENDATION REGARDING THE COMPANY'S PROPOSED UNDERGROUNDING PROGRAM?

A The Company's proposed large-scale overhead to underground conversion program should be rejected. While the concept of undergrounding has potential, the Company has not provided sufficient justification to move forward with a full-scale expansion at this time. The Company's own data, as presented in its cost-effectiveness analysis,

shows that undergrounding is the most expensive option under the UCT. The reliance on the societal cost test to justify the program is speculative, as it places a high value on long-term, uncertain benefits.

Furthermore, the Company's own experience with the initial pilot program demonstrates significant real-world challenges. The issues encountered in securing easements, which led to project delays and redesigns, highlight a major logistical hurdle. This lack of demonstrated ability to efficiently execute the program, coupled with the uncertainty of cost and benefits, makes the current proposal imprudent.

The Commission should follow the recommendation of the Liberty audit and require the Company to complete and thoroughly analyze the initial pilot projects before committing to a massive capital expenditure. This will allow for a more accurate assessment of actual costs and benefits and will ensure that any future expansion is based on sound data and a proven ability to execute, rather than on unsubstantiated projections. The Company has a responsibility to demonstrate a clear link between its investments and tangible improvements for customers before being granted further rate increases for this program. This recommendation would reduce the Company's test year capital expenditures by \$20 million.

V. LINE REGULATOR CONTROLLER PROJECT

Q PLEASE DESCRIBE THE COMPANY'S PROPOSED LINE REGULATOR CONTROLLER PROJECT.

A The Company's proposed Voltage Regulator Controller project aims to upgrade all controllers on its voltage regulators, integrating dynamic remote-control and monitoring capabilities into the electric distribution system. This initiative is part of the broader Distribution Circuit Modernization efforts, which focuses on deploying technologies to

1 improve grid reliability and resiliency. The project is designed to enhance power
2 quality, enabling customers to receive energy within tariff-specified limits. This not only
3 ensures regulatory compliance, but also allows customer equipment to operate more
4 efficiently. By supporting Conservation Voltage Reduction and Volt-VAR Optimization,
5 the new controllers can reduce energy consumption and peak demand.

6 Beyond these benefits, the project also provides cost-saving and safety
7 advantages. The two-way communication capability allows for proactive maintenance
8 and replacement of equipment before it fails, which helps prevent customer outages
9 and avoids the higher costs of emergent repairs. The ability to remotely monitor and
10 operate these devices also reduces the need for field crews to perform manual
11 inspections, improving the safety of electric line workers by limiting their exposure to
12 electrical and traffic hazards.

13 The Company plans to upgrade 220 regulator locations in 2025 and 217
14 locations in 2026, which is projected to be the final year of the mass deployment. After
15 this, the communicating regulator controller will become the standard installation for
16 new or replacement locations. The projected capital expenditures for this project are
17 \$10,526,000 for the bridge period and \$5,120,000 for the test year. A Benefit Cost
18 Analysis ("BCA") for this project is provided in Exhibit A-146 (SAM-5).

19 **Q WHAT WERE THE RESULTS OF THE COMPANY'S BCA SUPPORTING THE LINE**
20 **REGULATOR CONTROLLER PROJECT?**

21 A The Company forecasts that the line regulator controller project will produce
22 \$23,606,493 of benefits and cost \$15,129,138, which results in net benefits of
23 \$8,477,355.³⁹ In addition, the Company forecasts that the project will yield 56,625

³⁹ Exhibit A-146 (SAM-5).

minutes of avoided CMI, which have not been monetized and included in the above results of the BCA.⁴⁰

Q DO YOU HAVE ANY CONCERNS WITH THE METHODOLOGY DEPLOYED BY THE COMPANY TO CONDUCT THE BCA?

A Yes. The Company's DCF model treats the initial investment as a negative cash flow and future benefits as positive cash flows, which are then discounted to their Net Present Value ("NPV"). However, this model fails to include several key costs, such as taxes, Return on Equity ("ROE"), interest, and stranded costs. In a regulated monopoly, taxes and an ROE are collected from ratepayers through the Company's revenue requirements after the investment is put into service. By excluding them from the BCA, the Company underestimates the true financial burden on customers. The model does not factor in the interest paid on debt used to finance the project. This is another cost ultimately borne by ratepayers that is not reflected in the analysis. The BCA does not account for the possibility of stranded costs. If an asset is replaced before the end of its depreciable life, customers are forced to pay for both the original, now-retired asset and its replacement. This double payment represents a significant financial risk to ratepayers that the Company's analysis ignores.

By not including these additional costs, the Company's BCA presents a misleading picture of the project's cost-effectiveness. The reported net benefits appear artificially high because they are not offset by the full spectrum of costs customers will ultimately pay. In a regulated environment, where consumers bear the full cost of any approved investments, the decision-making process should prioritize rate affordability. If the analysis were to properly include taxes, ROE, interest expense, and potential

⁴⁰ *Id.*

1 stranded costs, the project's true costs would be significantly higher. This more
2 accurate assessment would likely demonstrate that the project is less cost-effective
3 than the Company claims. Ultimately, the Company's current BCA modeling approach
4 is inappropriate for making investment decisions that directly impact customer rates.

5 **Q ARE THE INPUT ASSUMPTIONS UTILIZED BY THE COMPANY IN THE LINE**
6 **REGULATOR CONTROLLER BCA REASONABLE?**

7 A No. A majority of the monetized benefits, \$12,880,000, are calculated based on the
8 assumption that current line regulators installed prior to 2000 will *all fail* over the next
9 ten years. However, the Company has not provided any analysis to support this
10 assumption. Excluding the forecasted benefit of future line regulator failures would
11 reduce the NPV of benefits to \$10,726,493, which is \$4,402,645 less than the cash
12 value of the project. Alternatively, if only 273 of the line regulators installed prior to
13 2000 would fail, then the project's net benefits would be negative, and the project would
14 no longer be forecasted to be cost-effective.

15 **Q GIVEN THE ISSUES IDENTIFIED IN THE COMPANY'S LINE REGULATOR**
16 **CONTROLLER BCA, WHAT IS YOUR RECOMMENDATION?**

17 A I recommend that the Company reduce the proposed pace of the line regulator
18 controller project to 25% of the proposed installation rate. As a result, the Company's
19 plans to upgrade 220 regulator locations in 2025 and 217 locations in 2026, should be
20 reduced to 55 regulator location in 2025 and 54 locations in 2026. This would allow
21 the Company to utilize actual historical data to validate and improve the input
22 assumptions used in the line regulator controller BCA model, which the Company could
23 provide in its next rate case. I recommend that the capital expense be reduced by a

1 corresponding 25% of the proposed expense for the line regulator controller project to
2 reflect the reduction in installation rate. This would reduce the Company's projected
3 capital expenditures for this project by \$7,894,500 for the bridge period and \$3,840,000
4 for the test year.

5 **VI. HIGH VOLTAGE**
6 **DISTRIBUTION CAPITAL EXPENDITURES**

7 **Q PLEASE DESCRIBE THE COMPANY'S PROPOSED HVD CAPITAL**
8 **EXPENDITURES.**

9 A The HVD system consists of HVD lines, HVD and LVD substations, and a protective
10 relay system. It operates at 46 kV or 138 kV. The Company has 4,600 miles of
11 overhead HVD lines and 23 miles of underground HVD lines. The HVD system also
12 includes 1,138 substations, with 144 HVD, 830 LVD, and 164 Strategic Electric
13 Customer substations. Consumers Energy is proposing significant capital
14 expenditures for the HVD system in its filing. In the bridge period, the Company is
15 projecting HVD system expenditures of \$542,846,000, and for the test year, the
16 projected expenditures are \$417,546,000. These investments are intended to improve
17 reliability and resiliency, and to serve new customers.

18 **Q DID THE LIBERTY AUDIT INCLUDE RECOMMENDATIONS REGARDING THE**
19 **COMPANY'S HVD RELIABILITY INVESTMENTS?**

20 A Yes. Liberty did not find substantial need or benefit to increase investment in HVD
21 lines or in substations, given the fact that most SAIDI minutes, and most projected
22 SAIDI improvements, are related to the LVD system.⁴¹

⁴¹ Kelly Direct at 24.

1 **Q DOES THE COMPANY’S RECENT OUTAGE DATA CONFIRM THAT MOST OF THE**
2 **OUTAGE MINUTES ARE ATTRIBUTABLE TO THE LVD SYSTEM?**

3 A Yes. None of the outages reported in Table CTF-2 occurred at a fault location with a
4 voltage level exceeding 24.9 kV. Furthermore, Transmission/Generation outages
5 accounted for only 0.4% of the total CMI. Thus, almost the entirety of outages over the
6 last three years (2022-2024) were the result of a fault that occurred in the LVD System.
7 As a result, recent outage data does not suggest a need to make investments to
8 improve the reliability of the HVD system.

9 **Q ARE ANY OF THE HVD SYSTEM CAPITAL EXPENDITURES BEING PROPOSED**
10 **PRIMARILY TO SUPPORT HVD SYSTEM RELIABILITY?**

11 A Yes. The proposed investments are broken down into several subprograms and
12 categories. The HVD Lines Reliability and HVD Substations Reliability subprograms
13 are being proposed to improve reliability in the HVD system.

14 The HVD Lines Reliability program includes projected expenditures of
15 \$133,667,000 in the bridge period and \$107,667,000 in the test year and will address
16 deteriorated HVD line assets through line rebuilds, pole top rehabilitation, pole
17 replacements, switch replacements, line sensor deployments, and right-of-way
18 acquisition.

19 The HVD Substations Reliability program includes projected expenditures of
20 \$47,322,000 in the bridge period and \$39,680,000 in the test year. These funds are
21 for circuit breaker and switcher replacements, transformer bushing replacements,
22 switch replacements, and other targeted equipment replacements.

Q BASED ON THE RECENT HVD SYSTEM RELIABILITY, WHAT IS YOUR RECOMMENDATION WITH RESPECT TO THE HVD LINES RELIABILITY AND HVD SUBSTATION RELIABILITY PROGRAMS?

A I recommend that the Company reduce capital expenditures to match the 2024 levels for the HVD reliability programs. The 2024 capital expenditure levels were the following:

- \$32,263,573 for the HVD Lines Reliability program.
- \$5,715,476 for the HVD Substations Reliability program.

Implementing this recommendation would result in the following capital expenditure reductions from the Company's proposed amounts:

- HVD Lines Reliability program:
 - Bridge period reduction of \$90,648,903.
 - Test year reduction of \$75,403,427.
- HVD Substations Reliability program:
 - Bridge period reduction of \$39,711,365.
 - Test year reduction of \$33,964,524.

VII. 138 KV DEDICATED CUSTOMER SUBSTATION

Q PLEASE DESCRIBE THE 138 KV CUSTOMER SUBSTATION.

A The 138 kV substation was being constructed for a dedicated customer in west Michigan.⁴² The Company had included \$20.619 million in the test year for this new substation, but as of July 2025, this project was cancelled, and the Company is in the process of cancelling the work orders.⁴³

⁴² Attachment 142, Page 1 of 313.

⁴³ Response to Data Request U21870-AB-CE-0695.

1 **Q WHAT IS YOUR RECOMMENDATION REGARDING THE 138 KV DEDICATED**
2 **SUBSTATION.**

3 A I recommend the \$20.619 million be removed from the test year rate base. This project
4 was never completed, and since it was designed for a single dedicated customer, the
5 project is not considered used and useful. Therefore it would be imprudent to include
6 this expenditure in the test year. I also recommend that the Company seek to recover
7 any sunk costs from the customer who canceled the project. This could be done
8 through a deposit or another mechanism specified in the original agreement with the
9 customer.

10 **VIII. CONCLUSION**

11 **Q PLEASE SUMMARIZE YOUR RECOMMENDATIONS.**

12 A I recommend that the Commission view the Company's request for further capital
13 investment with skepticism due to a pattern of increased spending without a
14 corresponding improvement in reliability. The Company's claim of improving reliability
15 is based on a selective view of its data, and a broader comparison with peer utilities
16 shows that Consumers consistently ranks near the bottom. The Company's capital
17 expenditures have increased by 49% over the past five years, but this has not resulted
18 in meaningful reliability gains for customers.

19 I recommend that instead of approving more funding for research and
20 investments that have only calculated savings of customer outage minutes without
21 regard to full program costs and benefits,⁴⁴ the Commission should demand the

⁴⁴ Some of the proposed investments appear to be for research with only expectations of reductions in customer outages, incomplete system-wide costs, and no benefit cost analyses. For example, the Metro Modernization project objective is stated to provide technology options for upgrading its vaults by evaluating sensors, assessing switching equipment, developing communications, and investigating remote-controls (McPhail Direct at 40). Further, this project does not have an estimate of

Company demonstrate a clear link between its investments and actual quantifiable and/or benchmarked improvements in reliability before any further rate increases are considered. In total I have proposed seven recommendations, two of which, LVD Pole Replacements and LVD Targeted Circuit Improvement, reduce the Company's proposed IRM capital expenditures. I have shown the impact of these adjustments on the Company's proposed IRM expense in Table CTF-3 below.

TABLE CTF-3			
<u>Summary of ABATE Adjustments to Company Proposed IRM</u>			
(\$ 1,000s)			
Line	Description	Test Year	Year After
1	LVD Pole Replacements	\$ (63,750)	\$ (63,750)
2	LVD Targeted Circuit Improvement	(45,057)	(45,057)
3	Total	<u>\$(108,807)</u>	<u>\$(108,807)</u>
4	Estimated Revenue Requirement Impact at Company ROE	\$ (5,781)	
5	Estimated Revenue Requirement Impact at ABATE ROE	\$ (5,570)	

As can be seen from Table CTF-3, my proposed adjustments to the LVD Pole Replacements and LVD Targeted Circuit Improvement project reduce the Company's proposed authorized IRM capital expenditures by approximately \$108.8 million in the test year and the year after. This lowers Consumers' projected test year IRM surcharge revenue deficiency by \$5.781 million based on the Company's proposed ROE of 10.25% and common equity ratio of 50.75%. However, at Mr. Walters' recommended ROE of 9.5% and 50% common equity ratio, it would lower Consumers' projected test year IRM surcharge revenue deficiency by \$5.570 million.

system-wide deployment costs nor a benefit cost analysis (Response to data Request U21870-AB-CE-0715).

Also, the Peer-to-Peer Automation Scheme project has a proposed initial investment of \$1.165M without a determination of costs for system-wide deployment and without a benefit cost analysis (Response to data Request U21870-AB-CE-0714).

The remaining five recommendations I have proposed impact the Company's base rate revenue requirement in the test year. These include adjustments to Overhead to Underground Conversions, Line Regulator Controller, HVD Lines Reliability, HVD Substations Reliability, and a 138 kV Dedicated Customer Substation. I have shown the impact of these adjustments in Table CTF-4 below.

TABLE CTF-4			
<u>Summary of ABATE Adjustments to</u>			
<u>Company Proposed Capital Expenditures and Revenue Requirement</u>			
(\$ 1,000s)			
<u>Line</u>	<u>Description</u>	<u>Bridge Period</u>	<u>Test Year</u>
1	Overhead to Underground Conversions	\$ -	\$ (20,000)
2	Line Regulatory Controller	(7,895)	(3,840)
3	HVD Lines Reliability	(90,649)	(75,403)
4	HVD Substations Reliability	(39,711)	(33,965)
5	138 kV Dedicated Customer Substation	-	(20,619)
6	Total	<u>\$(138,255)</u>	<u>\$(153,827)</u>
7	Estimated Revenue Requirement Impact at Company ROE		\$ (22,866)
8	Estimated Revenue Requirement Impact at ABATE ROE		\$ (22,030)

As shown in Table CTF-4, if the Commission adopts my recommendations, the Company's capital expenditures would be reduced by approximately \$138.3 million and \$153.4 million for the bridge period and test year, respectively. In total, I recommend a minimum reduction of \$22.9 million to Consumers' claimed revenue deficiency, based on the Company's requested 10.25% ROE. However, at Mr. Walters' recommended ROE of 9.5%, my adjustments would reduce the Company's claimed revenue deficiency by \$22.0 million.

Q DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A Yes, it does.

1 **Qualifications of Colin T. Fitzhenry**

2 **Q PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.**

3 A Colin T. Fitzhenry. My business address is 16690 Swingley Ridge Road, Suite 140,
4 Chesterfield, MO 63017.

5 **Q PLEASE STATE YOUR OCCUPATION.**

6 A I am a consultant in the field of public utility regulation and an Associate with the firm
7 of Brubaker & Associates, Inc. ("BAI"), energy, economic and regulatory consultants.

8 **Q PLEASE SUMMARIZE YOUR EDUCATIONAL BACKGROUND AND EXPERIENCE.**

9 **A** I received a Bachelor of Science in General Engineering from the University of Illinois
10 Urbana-Champaign, which provided a broad background in mechanics and control
11 systems. Prior to joining BAI, I served as an Engineer Intern for Dynegy Inc., where I
12 was involved with generation operation at both Vermilion Power Station and Tilton
13 Power Station.

14 Since joining BAI in January 2013, I have provided assistance in several
15 regulated utility matters. Some of these include resource planning, transmission
16 planning, fuel cost recovery, environmental compliance plans, mergers, asset transfers,
17 electrical and commodity price forecasting, and power procurement.

18 The firm of Drazen-Brubaker & Associates, Inc. was incorporated in 1972 and
19 assumed the utility rate and economic consulting activities of Drazen Associates, Inc.,
20 founded in 1937. In April, 1995 the firm of Brubaker & Associates, Inc. was formed. It
21 includes most of the former DBA principals and staff. Our staff includes consultants
22 with backgrounds in accounting, engineering, economics, finance, mathematics,
23 computer science and business.

1 Brubaker & Associates, Inc. and its predecessor firm have participated in over
2 700 major utility rate and other cases and statewide generic investigations before utility
3 regulatory commissions in 40 states, involving electric, gas, water, and steam rates and
4 other issues. Cases in which the firm has been involved have included more than 80
5 of the 100 largest electric utilities and over 30 gas distribution companies and pipelines.

6 While the firm has always assisted its clients in negotiating contracts for utility
7 services in the regulated environment, increasingly there are opportunities for certain
8 customers to acquire power on a competitive basis from a supplier other than its
9 traditional electric utility. The firm assists clients in identifying and evaluating purchased
10 power options, conducts RFPs and negotiates with suppliers for the acquisition and
11 delivery of supplies. We have prepared option studies and/or conducted RFPs for
12 competitive acquisition of power supply for industrial and other end-use customers
13 throughout the United States and in Canada, involving total needs in excess of 3,000
14 megawatts. The firm is also an associate member of the Electric Reliability Council of
15 Texas.

16 In addition to our main office in St. Louis, the firm also has branch offices in
17 Corpus Christi, Texas; Louisville, Kentucky and Phoenix, Arizona.

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1 MR. CAMPBELL: Thank you, Your Honor.

2 Mr. Walter's pre-file direct testimony consists
3 of a cover page, a table of contents, 74 pages of
4 questions and answers, and an appendix A setting out his
5 qualifications, and along with his pre-file direct
6 testimony, Mr. Walters sponsored exhibits AB-5 through AB-
7 19, and Mr. Walters did not have any rebuttal testimony.

8 JUDGE THOITS: Are there any objections to the
9 admission of this testimony or these exhibits?

10 Hearing none. The direct testimony of
11 Christopher Walters is bound in the record and exhibits AB-
12 5 through AB-19 are admitted.

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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 generation and distribution of)
electricity and for other relief.)

Case No. U-21870

Direct Testimony and Exhibits of

Christopher C. Walters

On behalf of

Association of Businesses Advocating Tariff Equity

September 30, 2025



Project 11862

**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 generation and distribution of)
electricity and for other relief.)
_____)

Case No. U-21870

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Appendix A: Qualifications of Christopher C. Walters

Exhibit AB-5:	Electric and Natural Gas Utilities Valuation Metrics
Exhibit AB-6:	Proxy Group
Exhibit AB-7:	Consensus Analysts' Growth Rates
Exhibit AB-8:	Constant Growth DCF Model (Consensus Analysts' Growth Rates)
Exhibit AB-9:	Payout Ratios
Exhibit AB-10:	Sustainable Growth Rate
Exhibit AB-11:	Constant Growth DCF Model (Sustainable Growth Rate)
Exhibit AB-12:	Multi-Stage Growth DCF Model
Exhibit AB-13:	Common Stock Market/Book Ratio
Exhibit AB-14:	Equity Risk Premium – Treasury Bond
Exhibit AB-15:	Equity Risk Premium – Utility Bond
Exhibit AB-16:	Bond Yield Spreads
Exhibit AB-17:	3 and 6 Month Treasury and Utility Bond Yields
Exhibit AB-18:	Beta
Exhibit AB-19:	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) Case No. U-21870
the generation and distribution of)
electricity and for other relief.)
_____)

Direct Testimony of Christopher C. Walters

I. INTRODUCTION

1
2 **Q PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.**

3 A Christopher C. Walters. My business address is 16690 Swingley Ridge Road,
4 Suite 140, Chesterfield, MO 63017.

5 **Q WHAT IS YOUR OCCUPATION?**

6 A I am a consultant in the field of public utility regulation and a Principal with the firm of
7 Brubaker & Associates, Inc. ("BAI"), energy, economic and regulatory consultants.

8 **Q PLEASE DESCRIBE YOUR EDUCATIONAL BACKGROUND AND EXPERIENCE.**

9 A This information is included in Appendix A to my testimony.

10 **Q ON WHOSE BEHALF ARE YOU APPEARING IN THIS PROCEEDING?**

11 A I am appearing on behalf of the Association of Businesses Advocating Tariff
12 Equity ("ABATE"). ABATE consists of large usage customers that purchase substantial
13 amounts of electric power and/or delivery service from Consumers Energy
14 Company ("Consumers Energy" or "Company").

Q WHAT IS THE PURPOSE OF YOUR DIRECT TESTIMONY?

A The purpose of my direct testimony is to address the cost of capital for Consumers Energy. I will specifically address the Company's investor-required return on equity ("ROE") and ratemaking capital structure.

Q PLEASE BRIEFLY SUMMARIZE YOUR CONCLUSIONS AND RECOMMENDATIONS IN THIS PROCEEDING.

A My conclusions and recommendations are as follows:

1. Reject Consumers Energy's proposed ROE of 10.25% and instead adopt my recommended ROE of 9.50%, which is based on my assessment of the current and expected capital market environment, Consumers Energy'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. Reject Consumers Energy's proposed capital structure including a permanent equity ratio of 50.75% and instead adopt my recommended equity ratio of 50.0%. My recommended equity ratio is consistent with the Commission's longstanding preference and authorizations over the last several years.
3. Reject Consumers Energy's requested overall ratemaking ROR of 6.35% and instead authorize an overall ratemaking ROR of 5.99% based on my recommendations, and would reduce Consumers Energy's requested revenue requirement by approximately \$74.3 million.

II. TESTIMONY OUTLINE

Q PLEASE DESCRIBE THE REMAINING SECTIONS OF YOUR TESTIMONY.

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.

1 In Section IV of my testimony, I address Consumers Energy's proposed capital
2 structure and cost of debt, outline how a fair ROE should be established, provide an
3 overview of the market's perception of Consumers Energy's investment risk, and
4 present the analyses I relied on to estimate an appropriate ROE for Consumers Energy.
5 Based on the results of several cost of equity estimation methods performed on publicly
6 traded utility companies, I estimate the current fair market ROE to fall within the range
7 of 9.00% to 10.00%. Based on my assessment of Consumers Energy's overall risk
8 profile and the results of the analytical methods, I recommend Consumers Energy be
9 awarded an ROE of 9.50%, which is the mid-point of my overall estimated range.

10 In Section V of my testimony, I respond to the testimony and analysis of
11 Consumers Energy witness Ann Bulkley. Ms. Bulkley's indicated range for a
12 reasonable ROE is 10.25% to 11.25%. She concludes that the Company's requested
13 ROE of 10.25% is reasonable and fairly balances the interests of ratepayers and
14 shareholders. As I demonstrate in this section of my testimony, Ms. Bulkley's indicated
15 range is unreasonable and should be rejected.

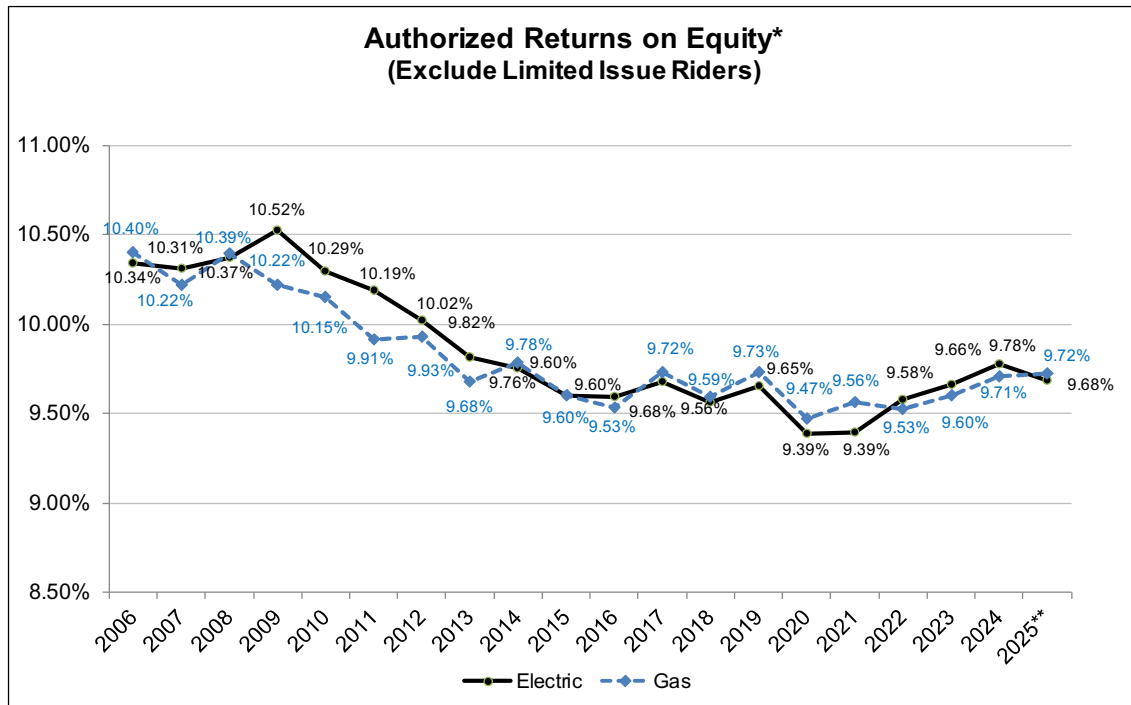
16 **III. INDUSTRY TRENDS**
17 **AND ECONOMIC ENVIRONMENT**

18 **A. Regulated Utility Industry Authorized**
19 **ROEs, Access to Capital, and Credit Strength**

20 **Q PLEASE DESCRIBE THE OBSERVABLE EVIDENCE ON TRENDS IN**
21 **AUTHORIZED ROES FOR ELECTRIC AND GAS UTILITIES.**

22 **A** Authorized ROEs for both electric and gas utilities have declined over the last 10 years,
23 as illustrated in Figure CCW-1, and have been below 10.0% for about the last
24 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 - June 2025, July 25, 2025 at page 3.

- 1 **Q PLEASE DESCRIBE THE DISTRIBUTION OF AUTHORIZED ROES FOR ELECTRIC**
- 2 **UTILITIES FOR THE LAST FEW YEARS.**
- 3 **A The distribution of authorized returns, annually, since 2016 is summarized in Table**
- 4 **CCW-1.**

TABLE CCW-1					
<u>Distribution of Authorized ROEs</u> (All Electric Utilities)*					
Year	Average	Median	Share of Decisions ≤ 9.5%	Share of Decisions ≤ 9.7%	Share of Decisions ≤ 10.0%
(1)	(2)	(3)	(4)	(5)	(6)
2016	9.60%	9.60%	41%	53%	94%
2017 ¹	9.68%	9.60%	40%	67%	81%
2018 ²	9.56%	9.58%	45%	61%	100%
2019	9.65%	9.65%	36%	58%	88%
2020 ³	9.39%	9.48%	64%	79%	98%
2021	9.39%	9.50%	57%	80%	97%
2022	9.58%	9.53%	50%	59%	79%
2023	9.66%	9.60%	38%	65%	90%
2024	9.78%	9.78%	24%	37%	85%
2025	9.65%	9.63%	46%	54%	96%
Average	9.59%	9.59%	44%	61%	91%
Median	9.62%	9.60%	43%	60%	92%
Source and Notes:					
S&P Global Market Intelligence, data through September 12, 2025.					
¹ Includes authorized base ROE of 9.4% for Nevada Power Company, which excludes incentives associated with the Lenzie facility.					
² Includes authorized base ROE of 9.6% for Interstate Power & Light Co., which excludes allowed ROE for generating facilities subject to special ratemaking principles.					
³ Includes authorized base ROE of 9.8% for Interstate Power & Light Co., which excludes allowed ROE for generating facilities subject to special ratemaking principles.					
*Excludes Limited Issue Rider Cases.					

- 1 The distribution shows that the majority of authorized ROEs since 2016 have
- 2 been below 9.7%, with many 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 deviated much from the range of 50.0% to 52.0%. As shown in Table CCW-2, 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					
<u>Trends in State Authorized Common Equity Ratios</u>					
(Industry)					
<u>Line</u>	<u>Year</u>	<u>Electric¹</u>		<u>Natural Gas¹</u>	
		<u>Average</u>	<u>Median</u>	<u>Average</u>	<u>Median</u>
	(1)	(2)	(3)	(4)	(5)
1	2016	49.70%	49.99%	51.85%	51.35%
2	2017	50.02%	49.85%	51.13%	51.76%
3	2018	50.60%	50.23%	51.56%	51.51%
4	2019	51.55%	51.37%	52.81%	52.42%
5	2020	50.93%	51.17%	52.34%	52.00%
6	2021	51.01%	52.00%	51.90%	52.00%
7	2022	51.57%	51.92%	51.65%	52.00%
8	2023	51.59%	52.27%	52.45%	52.00%
9	2024	51.07%	52.10%	52.25%	52.40%
10	2025	49.34%	50.00%	51.90%	51.87%
11	Min	49.34%	49.85%	51.13%	51.35%
12	Max	51.59%	52.27%	52.81%	52.42%
13	Average	50.74%	51.09%	51.99%	51.93%
14	Median	50.97%	51.27%	51.90%	52.00%

Source and Notes:

¹ S&P Global Market Intelligence; data through September 12, 2025.

- Excludes Arkansas, Florida, Indiana and Michigan because they include non-investor capital.

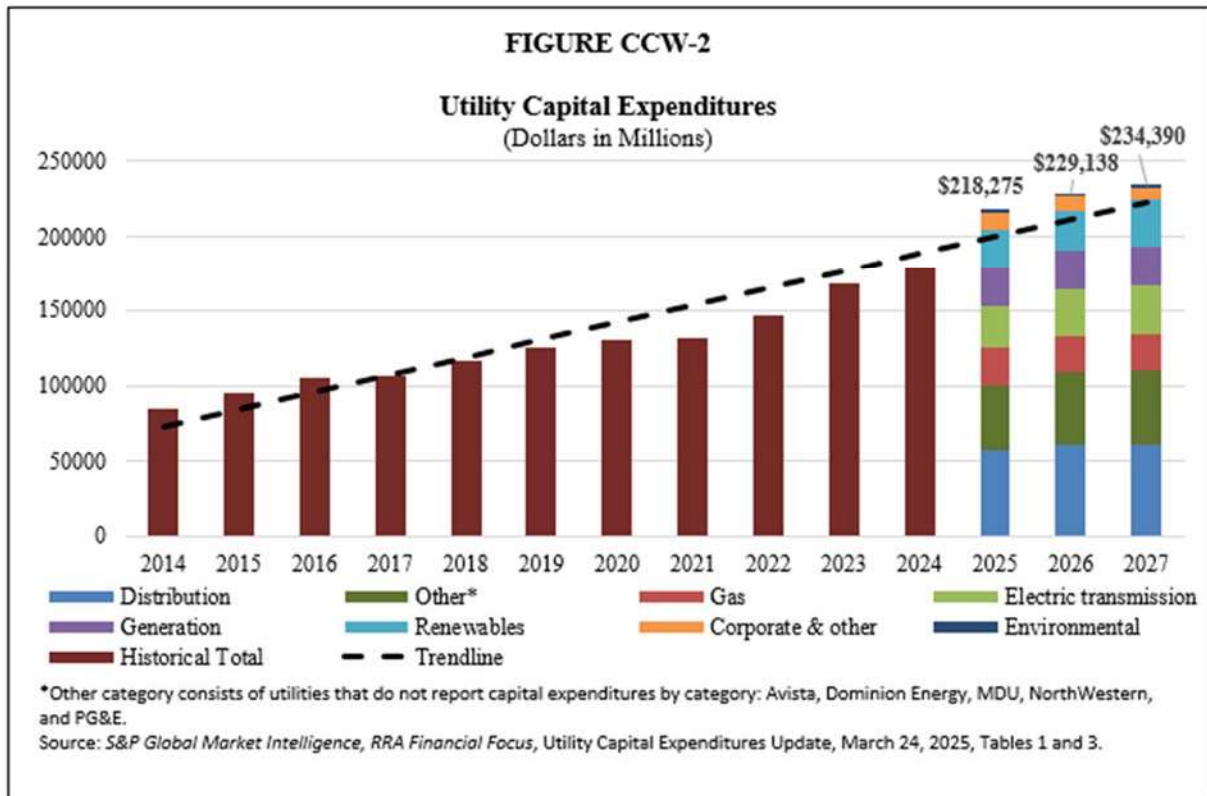
**Q HAVE UTILITIES BEEN ABLE TO ACCESS EXTERNAL CAPITAL TO SUPPORT
CAPITAL EXPENDITURE PROGRAMS?**

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 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.

¹S&P Global Market Intelligence, *RRA Financial Focus*: "Utility capital expenditures update," October 22, 2024.

As shown in Figure CCW-2, 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.



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 these 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

1 rates. If this is not done, utility rates will expand beyond the ability of customers to pay,
2 resulting in revenue constraints for utilities, which will impact their financial integrity.

3 **Q IS THERE EVIDENCE OF ROBUST VALUATIONS OF REGULATED UTILITY**
4 **EQUITY SECURITIES?**

5 A Yes. Strong valuations demonstrate that utilities can issue securities at favorable
6 prices and price multiples, signaling their ability to access equity capital on reasonable
7 terms and at a relatively low cost. As shown on Exhibit AB-5, the historical valuation
8 of utilities followed by *The Value Line Investment Survey* ("*Value Line*"), based on a
9 Price-to-Earnings ("P/E") ratio, Price-to-Cash Flow ratio, and Market Price-to-Book
10 value ratio, indicates utility security valuations today are very strong and robust relative
11 to the last several years. These strong valuations of utility stocks indicate that utilities
12 have access to equity capital under reasonable terms and at lower costs.

13 **Q WHAT CONCLUSION DO YOU DRAW FROM THIS OBSERVABLE MARKET DATA**
14 **IN FORMING YOUR RECOMMENDED ROE AND OVERALL ROR?**

15 A Generally, authorized ROEs, credit standing, and access to capital have been quite
16 robust for utilities over the last several years, even throughout the duration of the global
17 pandemic. It is critical that this Commission ensure that utility rates are increased no
18 more than necessary to provide fair compensation and maintain financial integrity.

B. Impact of Monetary Policy

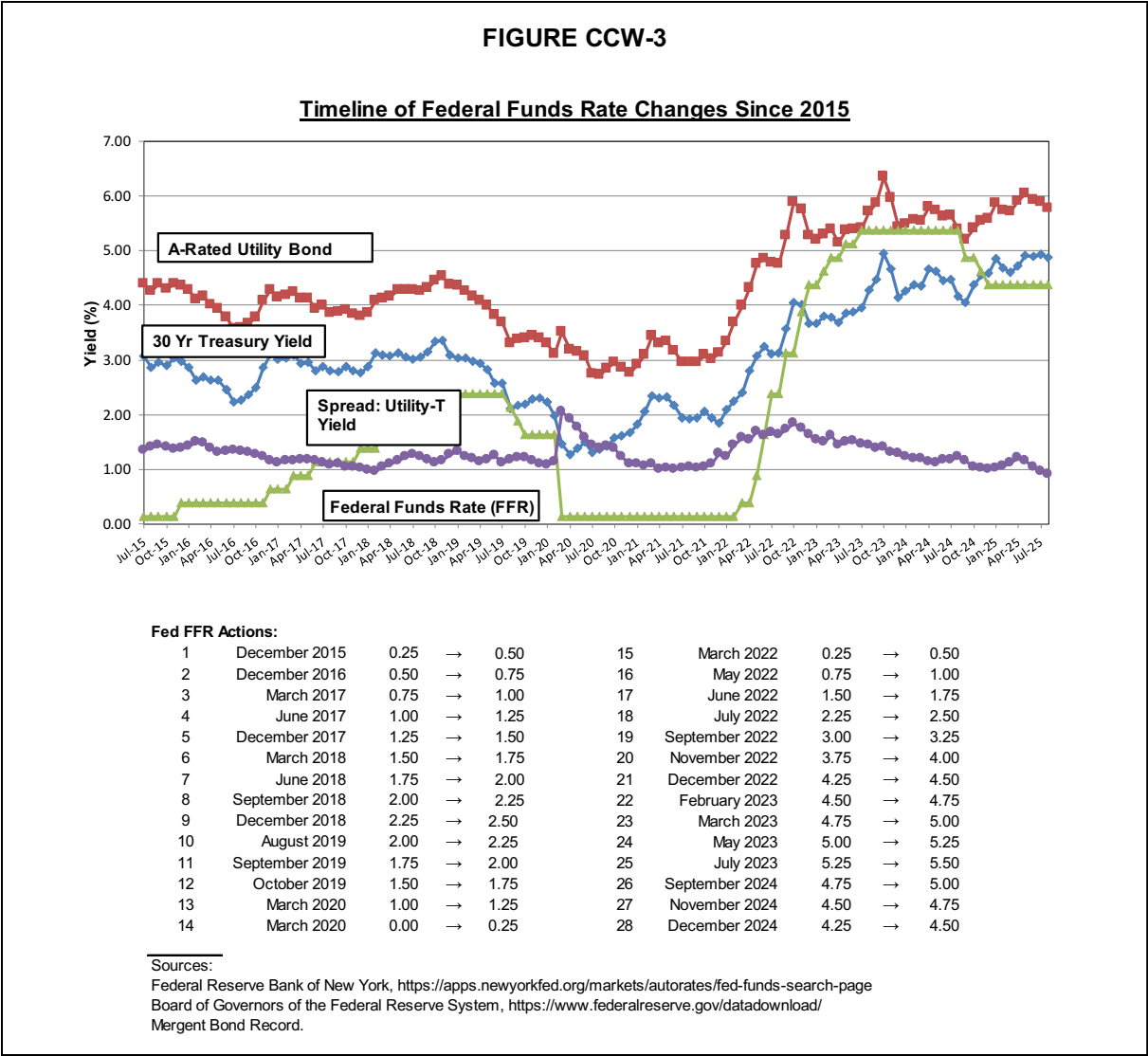
Q ARE THE FEDERAL OPEN MARKET COMMITTEE’S (“FOMC”) ACTIONS KNOWN TO THE MARKET PARTICIPANTS, AND IS IT REASONABLE TO BELIEVE THEY ARE REFLECTED IN THE MARKET’S VALUATION OF BOTH DEBT AND EQUITY SECURITIES?

A Yes, to both questions. The FOMC communicates its monetary policy objectives with a high degree of transparency, including its dual mandate to achieve maximum employment and stable inflation near 2%. To achieve these objectives, the FOMC adjusts its policy stance in phases depending on economic conditions. For example, in response to the pandemic-induced downturn, the FOMC adopted an accommodative stance by lowering the federal funds rate to near zero and engaging in Quantitative Easing, purchasing Treasury securities and agency mortgage-backed securities to support market liquidity and economic growth.

Beginning in March 2022, the FOMC transitioned to a tightening phase, raising the target federal funds rate. In June 2022, it began reducing its balance sheet (Quantitative Tightening) by allowing maturing Treasury and agency MBS securities to roll off its balance sheet without reinvestment. That phase of policy tightening persisted into 2024.

Since September 2024, the FOMC has lowered the federal funds rate three times, signaling a shift toward a more accommodative or neutral stance in response to evolving economic data. While balance sheet reduction continues, the pace has slowed considerably, especially for Treasury securities, reflecting a more measured policy approach.

1 Market reactions to these actions are reflected in the valuation of debt and
2 equity securities. A visualization of the market’s response to the federal funds rate
3 changes is shown in Figure CCW-3 below.



4 As shown in Figure CCW-3, the federal funds rate has risen more rapidly than
5 Utility and Treasury bond yields. Meanwhile, the yield spread between Utility bonds
6 and Treasury bonds has narrowed and is currently below its long-term average. This
7 narrower spread suggests that investors perceive lower relative risk in Utility bonds
8 compared to Treasuries, requiring less additional yield to hold them. This trend typically

1 reflects greater confidence in the financial stability and creditworthiness of utilities,
2 driven by factors such as stable earnings, favorable regulatory environments, or
3 improved credit fundamentals.

4 **Q HAS THE FED MADE RECENT COMMENTS CONCERNING MONETARY POLICY**
5 **AND THE POTENTIAL IMPACT ON INTEREST RATES?**

6 A Yes. On September 17, 2025, the FOMC released the following statement:

7 Recent indicators suggest that growth of economic activity moderated
8 in the first half of the year. Job gains have slowed, and the
9 unemployment rate has edged up but remains low. Inflation has moved
10 up and remains somewhat elevated.

11 The Committee seeks to achieve maximum employment and inflation at
12 the rate of 2 percent over the longer run. Uncertainty about the economic
13 outlook remains elevated. The Committee is attentive to the risks to both
14 sides of its dual mandate and judges that downside risks to employment
15 have risen.

16 In support of its goals and in light of the shift in the balance of risks, the
17 Committee decided to lower the target range for the federal funds rate
18 by 1/4 percentage point to 4 to 4-1/4 percent. In considering additional
19 adjustments to the target range for the federal funds rate, the Committee
20 will carefully assess incoming data, the evolving outlook, and the
21 balance of risks. The Committee will continue reducing its holdings of
22 Treasury securities and agency debt and agency mortgage-backed
23 securities. The Committee is strongly committed to supporting maximum
24 employment and returning inflation to its 2 percent objective.

25 In assessing the appropriate stance of monetary policy, the Committee
26 will continue to monitor the implications of incoming information for the
27 economic outlook. The Committee would be prepared to adjust the
28 stance of monetary policy as appropriate if risks emerge that could
29 impede the attainment of the Committee's goals. The Committee's
30 assessments will take into account a wide range of information,
31 including readings on labor market conditions, inflation pressures and
32 inflation expectations, and financial and international developments.²

33 The Federal Reserve's September 17, 2025, FOMC statement indicates
34 that economic activity moderated in the first half of the year, with job gains

²[Federal Reserve Board - Federal Reserve issues FOMC statement](#), September 17, 2025.

1 slowing and unemployment edging up though remaining low. Inflation has risen
2 and remains somewhat elevated. The Committee noted that uncertainty about
3 the outlook is elevated and that downside risks to employment have increased.
4 In light of the shifting balance of risks, the Fed lowered the federal funds rate
5 target range by 0.25 percentage point to 4.00% to 4.25%. The Committee will
6 continue reducing its holdings of Treasury securities and agency debt and
7 mortgage-backed securities, while emphasizing its commitment to maximum
8 employment and returning inflation to 2%. The Fed reiterated it will closely
9 monitor incoming data and stands ready to adjust policy further if risks threaten
10 achievement of its dual mandate.

11 **Q WHAT DO INDEPENDENT ECONOMISTS' OUTLOOKS FOR FUTURE INTEREST**
12 **RATES AND INFLATION LEVELS INDICATE?**

13 A Independent economists, surveyed by *Blue Chip Financial Forecasts*, expect long-term
14 bond yields to remain relatively flat to marginally increase over the near term, while
15 maintaining levels that are still relatively low by historical levels. For example,
16 independent projections show that the consensus is the federal funds rate will decrease
17 while long-term interest rates, as measured by the 30-year Treasury bond, are
18 expected to remain relatively flat. Inflation, as measured through the Gross Domestic
19 Product ("GDP") price index, is expected to be a mix of marginal increases and
20 decreases over the near to intermediate term. This indicates that levels of inflation are
21 expected to be relatively flat over that period. The consensus projections for the next
22 several quarters are provided in Table CCW-3.

TABLE CCW-3

Blue Chip Financial Forecasts
Projected Federal Funds Rate, 30-Year Treasury Bond Yields, and GDP Price Index

<u>Publication Date</u>	<u>3Q</u> <u>2024</u>	<u>4Q</u> <u>2024</u>	<u>1Q</u> <u>2025</u>	<u>2Q</u> <u>2025</u>	<u>3Q</u> <u>2025</u>	<u>4Q</u> <u>2025</u>	<u>1Q</u> <u>2026</u>	<u>2Q</u> <u>2026</u>	<u>3Q</u> <u>2026</u>	<u>4Q</u> <u>2026</u>
<u>T-Bond, 30 yr.</u>										
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		
Apr-25			4.7	4.6	4.6	4.5	4.5	4.5	4.5	
May-25			4.7	4.6	4.5	4.5	4.4	4.4	4.4	
Jun-25			4.7	4.8	4.7	4.6	4.6	4.6	4.5	
Jul-25				4.8	4.8	4.7	4.7	4.7	4.6	4.6
Aug-25				4.8	4.9	4.8	4.7	4.7	4.6	4.6
Sep-25				4.8	4.9	4.7	4.7	4.7	4.6	4.6
<u>GDP Price Index</u>										
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		
Apr-25			2.7	2.7	2.7	2.5	2.5	2.1	2.2	
May-25			3.7	3.4	3.2	2.9	2.6	2.3	2.3	
Jun-25			3.7	2.9	3.4	2.8	2.6	2.2	2.3	
Jul-25				2.9	3.3	2.9	2.6	2.2	2.2	2.2
Aug-25				2.0	3.3	2.9	2.6	2.3	2.3	2.3
Sep-25				2.0	3.1	3.0	2.6	2.3	2.3	2.3

Source and Note:

Blue Chip Financial Forecasts, October 2024 through September 2025.

Actual Yields in Bold.

1 Q WHAT IS THE OUTLOOK FOR LONG-TERM INTEREST RATES, AND WHY DOES
2 IT MATTER?

3 A The outlook for long-term interest rates in the intermediate to long-term is also impacted
4 by the current Fed actions and the expectation that eventually the Fed's monetary
5 actions will return to more normal levels.

1 Long-term interest rate projections are illustrated in Table CCW-4:

TABLE CCW-4			
<u>30-Year Treasury Bond Yield Actual Vs. Projection</u>			
<u>Description</u>	<u>Actual</u>	<u>Near-Term Projected*</u>	<u>5- to 10-Year Projected</u>
<u>2020</u>			
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%
<u>2021</u>			
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%
<u>2022</u>			
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%
<u>2023</u>			
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%
<u>2024</u>			
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%
<u>2025</u>			
Q1	4.71%	4.53%	
Q2	4.83%	4.47%	4.4% - 4.3%
Source and Note:			
<i>Blue Chip Financial Forecasts</i> , January 2020 through September 2025.			
*Average of all 3 reports in Quarter.			

2 As outlined in Table CCW-4, the outlook for interest rates has moderated more
3 recently relative to 2020 and part of 2021. For example, when actual interest rates
4 were in the range of 1.4% to 2.1%, the near-term projections for 30-year Treasury yields
5 ranged from 1.9% to 2.8% in 2020-2021, while the projections five to ten years out were

1 in the range of 2.8% to 3.9%. Most recently, actual interest rates were approximately
2 4.5%, with near and intermediate projections in the range of 4.2% to 4.3%. While
3 interest rates were expected to increase drastically from their actual levels in the
4 2020-2021 period, those same projections are now flat to declining, which indicates the
5 cost of long-term capital might be near its peak.

6 **C. Market Sentiments and**
7 **Utility Industry Outlook**

8 **Q PLEASE DESCRIBE THE CREDIT RATING OUTLOOK FOR REGULATED**
9 **UTILITIES.**

10 **A** All credit rating agencies see rate affordability as an important consideration in
11 assessing utility credit, including Standard & Poor's ("S&P") and Moody's Investors
12 Service ("Moody's") as discussed below.

13 In its 2025 Outlook,³ S&P reports that North American regulated utilities face
14 continued credit pressure due to elevated capital spending, persistent cash flow deficits
15 (exceeding \$100 billion), and increasing physical risks such as wildfires and extreme
16 weather. In 2024, downgrades again outpaced upgrades, a five-year trend driven by
17 high capex, rising wildfire risk, and uneven regulatory outcomes. Despite ongoing
18 investment in the energy transition and data center growth (which may modestly lift
19 electricity sales by ~1% annually), financial metrics are deteriorating due to
20 underwhelming common equity issuance and high leverage. Hybrid security issuance
21 hit a record \$26 billion in 2024 and is expected to continue helping credit support.
22 Regulatory frameworks remain broadly credit supportive, though S&P downgraded its
23 view of Connecticut due to inconsistent returns and rising lag. Customer bill

³S&P Global Credit Ratings, "Industry Credit Outlook 2025 – North America Regulated Utilities," January 14, 2025.

1 affordability remains a key consideration, especially as capacity prices rise and new
2 infrastructure costs must be equitably allocated. Wildfire risk—particularly litigation and
3 insurance constraints—is becoming a systemic credit concern, now affecting nearly all
4 regions. However, given these aforementioned risks, S&P made several specific
5 observations about affordability in the context of regulated utilities' credit quality:

- 6 1. Electric bills as a share of household income: S&P noted that the
7 average electric customer bill is about 2% of U.S. median household
8 income, which it characterizes as “good value” relative to other
9 typical household expenses. Preserving this affordability is critical
10 to maintaining the industry's credit quality, as it underpins public and
11 regulatory support.
- 12 2. Risk from cost shifts due to data centers: S&P cautioned that if
13 utilities assign a significant portion of new infrastructure costs related
14 to data center growth to existing residential customers, it could lead
15 to higher customer bills. This would, in turn, pressure regulators to
16 limit future rate case increases, potentially impairing utilities' ability
17 to recover costs or earn authorized returns.
- 18 3. Capacity price increases: S&P warned that higher PJM capacity
19 prices—which are directly passed on to customers—could result in
20 greater customer dissatisfaction. This could prompt regulators to
21 limit increases in other parts of the customer bill, indirectly
22 constraining utilities' ability to maintain financial performance and
23 manage regulatory risk.

24 In sum, S&P views affordability as a cornerstone issue for the sector: sustained
25 rate increases or cost shifts that threaten affordability could erode regulatory support,
26 triggering credit risk. Therefore, the Commission should prioritize bill affordability when
27 analyzing risks the Company faces.

28 In a July 2025 update, S&P noted that 84% of the investment grade issuers had
29 either a stable or positive outlook, and reported that credit rating upgrades have
30 outpaced rating downgrades year-to-date.⁴

⁴S&P Global Credit Ratings, “Industry Credit Outlook Update – North America Regulated Utilities,” July 16, 2025.

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 "Stable" 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.⁵

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.⁶

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

⁵*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).

⁶*S&P Global Ratings*: "Industry Credit Outlook 2024: North America Regulated Utilities," January 9, 2024 at 8.

1 and onshoring of manufacturing activities, and tax transferability
2 provisions of the Inflation Reduction Act could somewhat offset
3 headwinds to utilities. Ongoing management actions to sell assets and
4 issue equity, in some cases, is supportive of parent companies' ratings.
5 Within Fitch's coverage, 90% of ratings hold Stable Rating Outlooks.
6 We expect limited rating movement in 2024. The number of upgrades
7 in 2023 so far exceeds the number of downgrades, and is driven by
8 positive rating actions on several parent holding companies and their
9 regulated subsidiaries.⁷

10 As outlined by Moody's, S&P, and Fitch above, credit analysts are focusing on
11 rate affordability as an important factor needed to support strong credit standing.
12 Customers must be able to afford to pay their utility bills in order for utilities to maintain
13 their financial integrity and strong investment grade credit standing. For this reason,
14 this Commission should carefully assess the reasonableness of cost of service in this
15 proceeding, including an appropriate overall ROR necessitated by a reasonably
16 cost-effective balanced ratemaking capital structure, and a ROE that represents fair
17 compensation but also maintains competitive, just, and reasonable rates.

18 **Q DO YOU BELIEVE THE PACE OF INCREASES FROM CONSUMERS ENERGY IS**
19 **PRESSURING RATE AFFORDABILITY?**

20 **A** Most likely, yes. Since 2020, Consumers Energy has received approximately
21 \$518.1 million in rate increases over five rate cases. If granted, the proposed increase
22 in this case (\$460.2 million) would mean that in a little more than five years, the
23 Company will have received nearly \$1 billion in base rate revenue increases.

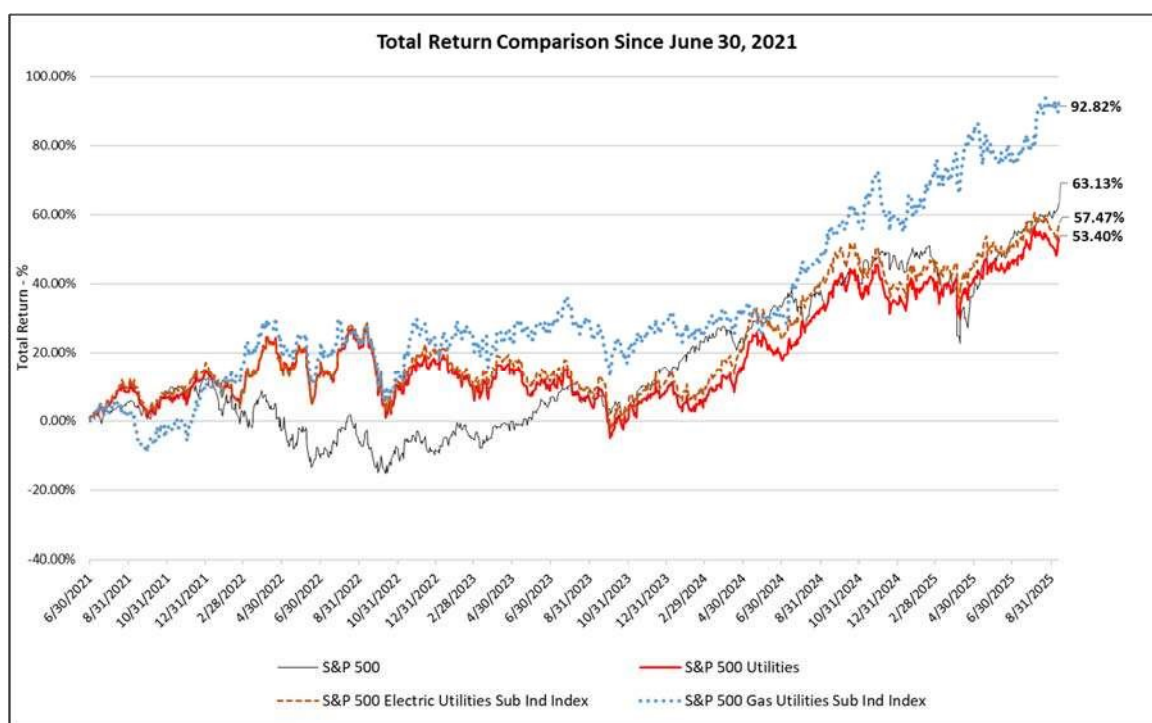
⁷*FitchRatings*. "North American Utilities, Power & Gas Outlook 2024," December 6, 2023 at 1.
(Emphasis Added).

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, and despite the risks discussed above, the electric utility sector has largely tracked the S&P 500, with a total return of 57.47% compared to the market's total return of 63.13%, as shown in Figure CCW-4.

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 index. This is because the S&P 500 is a market capitalization-

1 weighted index, meaning companies with larger market capitalizations have a greater
2 impact on the index's overall performance. This is explained in the S&P Dow Jones
3 Indices report "U.S. Equity Market Attributes April 2024," stating that:

4 Year-to-date, the S&P 500 remained up 5.57% (with 10 of the 11 sectors
5 up; Real Estate was down 9.86%), as breadth declined but remained
6 positive (302 up and 199 down, compared to last March's 369 and 134
7 YTD, respectively). The Magnificent 7 as a group still dominated,
8 accounting for 51% of the index return (which included Apple's 11.5%
9 YTD decline and Tesla's 26.2% YTD decline), as NVIDIA (up 74.5%
10 YTD) represented 41% of the S&P 500's YTD gain.⁸

11 While the S&P 500's strong performance in 2023 and early 2024 was largely
12 driven by a small group of "mega-cap" technology companies known as the Magnificent
13 7, the utility sector demonstrated positive and relatively stable returns over this period.
14 This reflects the defensive characteristics of regulated utilities, which are often viewed
15 by investors as safer assets during times of macroeconomic and geopolitical
16 uncertainty. Utilities' essential service nature, predictable cash flows, and supportive
17 regulatory environments helped them remain attractive to investors even amid elevated
18 inflation, rising interest rates, and global instability.

19 **IV. RATE OF RETURN**

20 **Q PLEASE GENERALLY DESCRIBE WHAT IS MEANT BY THE OVERALL ROR AS**
21 **IT RELATES TO RATEMAKING FOR REGULATED UTILITIES.**

22 **A** The overall ROR in utility ratemaking represents the weighted average cost of capital
23 a utility is allowed to earn on its rate base. It combines the cost of debt and the
24 authorized ROE, weighted by the utility's capital structure.

⁸<https://www.spqglobal.com/spdji/en/documents/commentary/market-attributes-us-equities-202404.pdf>. (Emphasis Added).

1 **A. Capital Structure**

2 **Q WHAT IS CONSUMERS ENERGY'S PROPOSED CAPITAL STRUCTURE?**

3 A Consumers Energy's proposed capital structure is summarized in Table CCW-5:

Table CCW-5	
<u>Investor-Supplied Capital Structure</u>	
<u>Description</u>	<u>Weight</u>
Long-term Debt	49.25%
Common Equity	<u>50.75%</u>
Total	100.00%

4 **Q DO YOU HAVE ANY COMMENTS ON CONSUMERS ENERGY'S PROPOSED**
5 **CAPITAL STRUCTURE?**

6 A Yes. As I will discuss, Consumers Energy's proposed equity ratio of 50.75% is
7 relatively higher than the equity ratio for the proxy group used to estimate the cost of
8 equity for Consumers Energy. As shown on Exhibit AB-6, the proxy group has an
9 average common equity ratio of 40.1% (including short-term debt) and 43.8%
10 (excluding short-term debt). This indicates that Consumers Energy has less financial
11 risk compared to the proxy group.

12 **Q HAS THIS COMMISSION PREVIOUSLY RECOGNIZED THE NEED TO HAVE A**
13 **BALANCED CAPITAL STRUCTURE?**

14 A Yes. For several rate case cycles now, this Commission has consistently authorized
15 an equity ratio of 50.0% for the major utilities it regulates including DTE Electric, DTE
16 Gas, as well as both of Consumers Energy's operating gas and electric divisions.

1 In fact, the Commission reiterated that stance just a few months ago in
2 Consumers Energy's recent electric rate case (Case No. U-21585). In its Final Order,
3 the Commission stated as follows:

4 Given the above, the Commission adopts the thorough and well-
5 reasoned findings and recommendations of the ALJ. The Commission
6 finds that the balanced capital structure most appropriately balances the
7 interests of the utility's investors and customers, consistent with the
8 holdings in Bluefield and Hope. As such, the Commission adopts a
9 balanced capital structure of 50% debt to 50% equity, utilizing the
10 Attorney General's methodology.

11 Consumers Energy has not presented any credible evidence to depart from the
12 Commission's stated preference and in support of increasing its authorized equity ratio
13 from 50.0% to 50.75%.

14 **Q ARE YOU RECOMMENDING AN ADJUSTMENT TO CONSUMERS ENERGY'S**
15 **CAPITAL STRUCTURE?**

16 A Yes, I am. I recommend the Commission continue to authorize Consumers Energy its
17 currently authorized equity ratio of 50.0%.

18 **B. Cost of Debt**

19 **Q WHAT COST OF DEBT IS CONSUMERS ENERGY PROPOSING?**

20 A Consumers Energy is proposing an embedded cost of long-term debt of 4.54%.

21 **Q ARE YOU TAKING ISSUE WITH CONSUMERS ENERGY'S PROPOSED COST OF**
22 **DEBT?**

23 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,”⁹ and defined the ratepayer/investor balance as follows:

⁹*Bluefield*, 262 U.S. at 692-693.

1 The return should be reasonably sufficient to assure confidence in the
2 financial soundness of the utility and should be adequate, under efficient
3 and economical management, to maintain and support its credit and
4 enable it to raise the money necessary for the proper discharge of its
5 public duties.¹⁰

6 As such, a fair ROR is based on the expectation that the utility's costs reflect
7 efficient and economical management, and the return will support its credit standing
8 and access to capital, but the return will not be in excess of this level. Utility rates that
9 are consistent with these standards will be just and reasonable, and compensation to
10 the utility will be fair and support financial integrity and credit-standing, under economic
11 management of the utility.

12 **Q PLEASE DESCRIBE THE PROCESS YOU HAVE USED TO ESTIMATE**
13 **CONSUMERS ENERGY'S COST OF COMMON EQUITY.**

14 A First, I assessed the market's perspective of Consumers Energy's risk. Then, I
15 developed a proxy group of publicly traded utility companies that have similar risks and
16 characteristics to Consumers Energy and compared potential differences in risks. I
17 then performed several models based on financial theory to estimate Consumers
18 Energy's cost of common equity. These models are: (1) a constant growth Discounted
19 Cash Flow ("DCF") model using consensus analysts' growth rate projections; (2) a
20 constant growth DCF model using sustainable growth rate estimates; (3) a multi-stage
21 growth DCF model; (4) a Risk Premium method; and (5) a Capital Asset Pricing
22 Model ("CAPM").

¹⁰*Id.* at 693 (Emphasis Added).

1 **Q WHY MUST THE COST OF EQUITY BE ESTIMATED RATHER THAN DIRECTLY**
2 **OBSERVED?**

3 A The cost of equity cannot be directly observed because equity investors do not receive
4 fixed, contractual payments like debt holders do. Instead, they are compensated
5 through uncertain and variable returns in the form of dividends and capital appreciation.
6 These returns depend on a range of unpredictable factors, including company
7 performance, market conditions, and investor sentiment. As such, the cost of equity
8 represents an investor's required ROR, which must be estimated using financial
9 models rather than measured directly from observable market transactions.

10 **Q WHY IS IT NECESSARY TO APPLY MULTIPLE METHODS TO ESTIMATE THE**
11 **COST OF EQUITY?**

12 A Because the cost of equity is an estimate based on forward-looking expectations and
13 assumptions, no single model can definitively or universally capture the "true" cost.
14 Each model, such as the DCF model, the CAPM, and the Risk Premium approach, has
15 its own theoretical foundation, strengths, and limitations. These models rely on
16 different assumptions and input variables such as projected growth rates or equity risk
17 premiums which can vary in reliability. Using multiple models provides a more
18 comprehensive and balanced view, helps identify outlier results, and increases
19 confidence that the final estimate reasonably reflects investor expectations under
20 current market conditions.

1 **Q DOES THE USE OF MULTIPLE METHODS IMPROVE THE ACCURACY OF THE**
2 **ESTIMATE?**

3 A Yes. Employing multiple methods helps to cross-check and validate the results,
4 mitigate the impact of any one model's limitations or potentially flawed assumptions,
5 and reduce reliance on any single uncertain input. By considering results from different
6 perspectives, a more informed and credible estimate can be made. This approach is
7 consistent with both sound financial practice and regulatory expectations for fair and
8 reasonable return determinations.

9 **D. Investment Risk**
10 **Assessment of Consumers Energy**

11 **Q PLEASE DESCRIBE THE MARKET'S ASSESSMENT OF CONSUMERS ENERGY'S**
12 **INVESTMENT RISK.**

13 A The market's assessment of a company's investment risk is generally described by
14 credit rating analysts' reports. The current credit ratings for Consumers Energy is A-
15 from S&P and A3 from Moody's.¹¹ Consumers Energy's outlook from S&P is "Negative"
16 while its outlook from Moody's is considered "stable". In its September 2025 report
17 covering Consumers Energy, S&P stated as follows:

18 ***Outlook***

19 The stable rating outlook on CE reflects our expectation that
20 management will focus on its core utility operations and reach
21 constructive regulatory outcomes to avoid increasing business risk. We
22 expect CE will maintain stand-alone financial measures consistent with
23 the middle of the range for its financial risk profile category, specifically
24 FFO to debt of 17%-20%.

25 We expect Consumers Energy Co. (CE) to continue to effectively
26 manage its regulatory risk. We believe Michigan's regulatory construct
27 is above average compared with peers because of the benefit of a
28 streamlined 10-month rate case process. Other constructive rate

¹¹S&P Capital IQ, accessed on September 12, 2025.

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.

CE is currently seeking rate increases in both electric and gas businesses. In June 2025 CE filed for a \$460 million electric rate increase, based on a 10.25% ROE (previously approved 9.9%) and an equity layer of 42.94% (previously approved 41.73%). Separately, CE is seeking a \$217 million rate increase in its gas business. This is premised on a ROE of 10.25% (previously approved 9.9%) and an equity layer of 42.58% (previously approved 41.48%).

We continue to monitor related developments. We will also continue to monitor the company's performance in light of a 2024 third-party audit which indicated a below-average system reliability assessment for CE as measured by system and customer average interruption indices.¹²

As noted by S&P, Consumers Energy's credit profile remains solid, as S&P reaffirmed the utility's A- credit rating and "Stable" outlook, signaling continued confidence in the company's financial position..

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 Consumers Energy'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

¹²S&P Capital IQ RatingsDirect, "Full Analysis | Consumers Energy Co," September 15, 2025.

1 and biases which would make the reliance on a single estimate undesirable and
2 potentially less accurate. A proxy group of comparable risk companies adds reliability
3 to the estimates by mitigating the potential for bias that may be introduced by
4 measurement errors of model inputs.

5 **Q PLEASE DESCRIBE HOW YOU IDENTIFIED A PROXY UTILITY GROUP THAT**
6 **COULD BE USED TO ESTIMATE CONSUMERS ENERGY'S CURRENT MARKET**
7 **COST OF EQUITY.**

8 A I started with the same utility company proxy group relied on by Consumers Energy
9 witness Ms. Bulkley. I then reviewed each company to see if there were any significant
10 factors that would potentially impact the overall risk level. Such factors would include
11 significant merger and/or acquisition activity, credit ratings upgrades/downgrades, or
12 dividend cuts. I also reviewed to make sure they were covered by an analyst in the
13 *Value Line Investment Survey*.

14 Based on my review, I found that two companies needed to be removed from
15 the proxy group: NorthWestern Corporation and TXNM Energy. On August 19, 2025,
16 NorthWestern Corporation announced it is being acquired by Black Hills Corporation.
17 TXNM Energy, formerly PNM Resources, announced that it was being acquired by
18 Blackstone Infrastructure Partners on May 19, 2025. After removing those two
19 companies, I have included 17 companies in my proxy group.

20 **Q HOW DOES THE INVESTMENT RISK OF CONSUMERS ENERGY COMPARE TO**
21 **THAT OF THE PROXY GROUP?**

22 A As shown on my Exhibit AB-6, the proxy group has average credit ratings of BBB+ and
23 Baa2 from S&P and Moody's, respectively. The proxy group's average rating of BBB+

from S&P is one notch lower than Consumers Energy's rating of A- from S&P. The proxy group's average rating of Baa2 from Moody's is two notches lower than Consumers Energy's rating of A3 from Moody's.

As shown on the same schedule, the proxy group has an average common equity ratio of 40.1% (including short-term debt) and 43.8% (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.

Consumers Energy's credit ratings are higher than the proxy group. Similarly its requested equity ratio of 50.75% exceeds the proxy group's equity ratio. On balance, these observations indicate that Consumers Energy is of less risk than my proxy group. I will take its relative risk into consideration in determining my recommendation.

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:

$$P_0 = \frac{D_1}{(1+K)^1} + \frac{D_2}{(1+K)^2} + \dots + \frac{D_\infty}{(1+K)^\infty} \quad (\text{Equation 1})$$

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:

1 $K = D_1/P_0 + G$ (Equation 2)

2 K = Investor's required return
3 D_1 = Dividend in first year
4 P_0 = Current stock price
5 G = Expected constant dividend growth rate

6 Equation 2 is referred to as the annual "constant growth" DCF model.

7 **Q PLEASE DESCRIBE THE INPUTS TO YOUR CONSTANT GROWTH DCF MODEL.**

8 A As shown in Equation 2 above, the DCF model requires a current stock price, the
9 expected dividend, and the expected growth rate in dividends.

10 **Q WHAT STOCK PRICE HAVE YOU RELIED ON IN YOUR CONSTANT GROWTH**
11 **DCF MODEL?**

12 A I relied on the average of the weekly high and low stock prices of the utilities in the
13 proxy group over a 13-week period ending on September 12, 2025. An average stock
14 price is less susceptible to market price variations than a price at a single point in time.
15 Therefore, an average stock price is less susceptible to aberrant market price
16 movements, which may not reflect the stock's long-term value.

17 **Q WHAT DIVIDEND DID YOU USE IN YOUR CONSTANT GROWTH DCF MODEL?**

18 A I used each proxy company's most recently paid quarterly dividend as reported in
19 *Value Line*.¹³ This dividend was annualized (multiplied by 4) and adjusted for next
20 year's growth to produce the D_1 factor for use in Equation 2 above. In other words, I
21 calculate D_1 by multiplying the annualized dividend (D_0) by $(1+G)$.

¹³The Value Line Investment Survey, July 18, August 8, and September 5, 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 ROR, 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.¹⁴ 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 September 12, 2025, and all were reported online.¹⁵

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 analysts'

¹⁴See, e.g., David Gordon, Myron Gordon, and Lawrence Gould, Choice Among Methods of Estimating Share Yield, The Journal of Portfolio Management, Spring 1989.

¹⁵www.zacks.com; LSEG Workspace; <https://www.capitaliq.spglobal.com/>.

1 earnings growth forecasts. A simple average of the growth forecasts gives equal
2 weight to all surveyed analysts' projections. Therefore, a simple average, or arithmetic
3 mean, of analysts' forecasts is a good proxy for investor expectations.

4 The growth rates I used in my DCF analysis are shown in Exhibit AB-7. The
5 average growth rate for my proxy group is 7.22% and a median growth rate of 6.87%.

6 **Q WHAT ARE THE RESULTS OF YOUR CONSTANT GROWTH DCF MODEL?**

7 A As shown in Exhibit AB-8, page 1, the average and median constant growth DCF
8 returns for my proxy group for the 13-week analysis are 11.05% and 10.50%,
9 respectively.

10 **Q ARE THERE LIMITATIONS OF THE CONSTANT GROWTH DCF ANALYSIS?**

11 A Yes. The constant growth DCF analysis for my proxy group is based on a group
12 average long-term growth rate of 7.22%. The three- to five-year growth rates are
13 approximately 77% higher than the long-term projected GDP growth rate of 4.09%,
14 described below. As I explain in detail below, a utility's growth rate cannot exceed the
15 growth rate of the economy in which it provides services in perpetuity, which is the time
16 period assumed by the DCF model.

17 **Q HOW DID YOU IDENTIFY THE LONG-TERM PROJECTED GDP GROWTH RATE?**

18 A Although there may be short-term peaks, the long-term sustainable growth rate for a
19 utility stock cannot exceed the growth rate of the economy in which it sells its goods
20 and services. The long-term maximum sustainable growth rate for a utility investment
21 is limited by the projected long-term GDP growth rate, as that reflects the projected
22 long-term growth rate of the economy. The consensus projection for U.S. GDP, as

published by Blue Chip Financial Forecasts, is an annual growth rate of approximately 4.09% 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 a company, as opposed to being paid out as dividends. The earnings retention ratio is calculated as one minus the dividend payout ratio. As the payout ratio decreases, the retention ratio increases, leading to stronger growth as a company funds more investments using retained earnings.

1 The payout ratios of the proxy group are shown in my Exhibit AB-9. These
2 dividend-payout ratios and earnings-retention ratios then can be used to develop a
3 long-term growth rate driven by earnings retention.

4 The data used to estimate the long-term sustainable growth rate is based on
5 Consumers Energy's current market-to-book ratio and on *Value Line's* three- to
6 five-year projections of earnings, dividends, earned returns on book equity, and stock
7 issuances.

8 As shown in Exhibit AB-10, the average and median sustainable growth rates
9 for the proxy group using this internal growth rate model are 5.29% and 4.83%,
10 respectively.

11 **Q WHAT IS THE DCF ESTIMATE USING THESE SUSTAINABLE GROWTH RATES?**

12 A A DCF estimate based on these sustainable growth rates is developed in Exhibit AB-
13 11. As shown there, and using the same formula in Equation 2 above, a sustainable
14 growth DCF analysis produces proxy group average and median DCF results for the
15 13-week period of 9.05% and 8.85%, respectively.

16 **H. Multi-Stage Growth DCF Model**

17 **Q HAVE YOU CONDUCTED ANY OTHER DCF STUDIES?**

18 A Yes. As previously noted, the DCF model is intended to represent the present value
19 of an endless series of future cash flows. Nevertheless, the initial constant growth DCF
20 that I created is based on analyst growth-rate projections, providing a plausible
21 representation of rational investment expectations over the next three-to-five years.
22 The limitation of this constant growth DCF model is that it cannot reflect a reasonable
23 expectation of a shift in growth from a high or low short-term rate to a rate that aligns

1 more with long-term sustainable growth. To accommodate changing growth
2 expectations, I conducted a multi-stage DCF analysis that reflects growth rate change
3 over time.

4 **Q WHY DO YOU BELIEVE GROWTH RATES CAN CHANGE OVER TIME?**

5 A The growth rate projections by analysts for the next three-to-five years are subject to
6 change as the outlook for utility earnings-growth evolves. Utility companies experience
7 fluctuations in their investment cycles. When these companies are undertaking
8 substantial investments, the growth of their rate base accelerates, leading to an
9 increase in earnings growth. However, once a major construction cycle reaches
10 completion or plateaus, the growth in the utility rate base slows down, and its earnings
11 growth rate declines from an abnormally high three-to-five-year rate to a lower,
12 sustainable growth rate.

13 As construction cycles become longer in duration, even with an aggressive
14 construction plan, the growth rate of the utility will naturally slow due to a decrease in
15 rate base growth as the utility has limited human and capital resources to expand its
16 construction activities. Therefore, the three-to-five-year growth rate projection should
17 be viewed as a long-term sustainable growth rate, but not without considering the
18 current market conditions, industry trends, and determining whether the
19 three-to-five-year growth outlook is feasible and sustainable.

20 **Q PLEASE DESCRIBE YOUR MULTI-STAGE DCF MODEL.**

21 A The multi-stage DCF model reflects the possibility of non-constant growth for a
22 company over time. The multi-stage DCF model reflects three growth periods: (1) a
23 short-term growth period consisting of the first five years; (2) a transition period,

1 consisting of the next five years (6 through 10); and (3) a long-term growth period
2 starting in year 11 and extending into perpetuity.

3 For the short-term growth period, I relied on the consensus of analysts' growth
4 projections described above in relationship to my constant growth DCF model. For the
5 transition period, the growth rates were reduced or increased by an equal factor
6 reflecting the difference between the analysts' growth rates and the long-term
7 sustainable growth rate. For the long-term growth period, I assumed each company's
8 growth would converge to the maximum sustainable long-term growth rate.

9 **Q WHY IS THE GDP GROWTH PROJECTION A REASONABLE PROXY FOR THE**
10 **MAXIMUM SUSTAINABLE LONG-TERM GROWTH RATE?**

11 **A** As discussed above, utilities cannot indefinitely sustain a growth rate that exceeds the
12 growth rate of the economy in which they sell services. A utility's earnings and dividend
13 growth is created by increased utility investment in its rate base. Examples of what
14 can drive such investment are: service area economic growth, system reliability
15 upgrades, or state and federal green energy initiatives. As such, nominal GDP growth
16 is a reasonable upper limit for utility sales growth, rate base growth, and earnings
17 growth in the long-run. Therefore, the U.S. GDP nominal growth rate is a conservative
18 proxy for the highest sustainable long-term growth rate of a utility.

1 **Q HOW DID YOU DETERMINE A LONG-TERM GROWTH RATE THAT REFLECTS**
2 **THE CURRENT CONSENSUS OF INDEPENDENT MARKET PARTICIPANTS?**

3 A I relied on the consensus of long-term GDP growth projections by independent
4 economists. Blue Chip Financial Forecasts publishes the consensus for GDP growth
5 projections twice a year. These projections reflect current outlooks for GDP and are
6 likely to be influential on investors' expectations of future growth outlooks. The
7 consensus of projected GDP growth is about 4.09% over the next 10 years.

8 **Q DO YOU CONSIDER OTHER SOURCES OF PROJECTED LONG-TERM GDP**
9 **GROWTH?**

10 A Yes, and these alternative sources corroborate the consensus analysts' projections I
11 relied on. Several projections are shown in Table CCW-6.

TABLE CCW-6

GDP Forecasts

<u>Source</u>	<u>Projected Period</u>	<u>Real GDP</u>	<u>Inflation</u>	<u>Nominal GDP</u>
Blue Chip Financial Forecasts ¹	5-10 Yrs	2.0%	2.1%	4.1%
EIA - Annual Energy Outlook ²	26 Yrs	1.8%	2.1%	3.9%
Congressional Budget Office ³	30 Yrs	1.6%	2.0%	3.7%
Moody's Analytics ⁴	30 Yrs	2.0%	2.1%	4.2%
Social Security Administration ⁵	75 Yrs	1.5%	2.4%	4.0%
Economist Intelligence Unit ⁶	31 Yrs	1.6%	2.3%	4.0%

Sources:

¹Blue Chip Financial Forecasts, June 2, 2025 at 14.

²U.S. EnergyInformation Administration (EIA), Annual Energy Outlook 2025, April 15, 2025.

³Congressional Budget Office, Long-Term Budget Outlook, March 27, 2025.

⁴Moody's Analytics Forecast, last updated June 9, 2025.

⁵Social Security Administration, "2025 OASDI Trustees Report," Table VI.G6. June 18, 2025.

⁶S&P MI, Economist Intelligence Unit, downloaded on July 18, 2025.

1 As shown in the table above, the real GDP and the inflation fall in the range of
2 1.5% to 2.0% and 2.0% to 2.4%, respectively. This results in a nominal GDP in the
3 range of 3.7% to 4.2%. Therefore, the nominal GDP growth projections made by these
4 independent sources support my use of 4.09% as a reasonable estimate of market
5 participants' expectations for long-term GDP growth. The real GDP and nominal GDP
6 growth projections made by these independent sources support my use of 4.09% as a
7 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 4.09% 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-12, the average and median DCF ROEs for my proxy group using the 13-week average stock price are 8.62% and 8.21%, respectively.

Q PLEASE SUMMARIZE THE RESULTS FROM YOUR DCF ANALYSES.

A The DCF results are summarized in Table CCW-7. As described above, the results of the constant growth DCF using analysts' growth rates assume an average long-term growth rate of 7.22%, which is approximately 77% higher than the long-term projected GDP growth rate of 4.09%. 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 primary weight should be given to the sustainable growth and multi-stage

models of the DCF while minimal weight should be given to the constant growth DCF model based on three-to-five-year analyst growth rates.

Table CCW-7		
<u>Summary of DCF Results</u>		
<u>Description</u>	<u>Proxy Group</u>	
	<u>Mean</u>	<u>Median</u>
Constant Growth DCF Model (Analysts' Growth)	11.05%	10.50%
Constant Growth DCF Model (Sustainable Growth)	9.05%	8.85%
Multi-Stage DCF Model	8.62%	8.21%

I. Risk Premium Model

Q PLEASE DESCRIBE YOUR BOND YIELD PLUS RISK PREMIUM MODEL.

A The bond yield plus risk premium model is based on the principle that equity investors require a higher return than bond investors because common equity carries greater risk. Bonds benefit from fixed contractual payments and priority in bankruptcy, while dividends on common stock are discretionary and equity returns are not guaranteed. To estimate the equity risk premium ("ERP"), I rely on two approaches. First, I calculate the annual difference between regulatory commission-authorized ROEs for utility companies and the yield on U.S. Treasury bonds since 1986, which reflects the ERP over risk-free rates. Second, I calculate the annual difference between authorized ROEs and Moody's "A"-rated utility bond yields over the same period. I begin the analysis in 1986 because, as shown in Exhibit AB-13, utility stocks have consistently traded above book value since that time. A market-to-book ratio above 1.0x indicates

1 that authorized ROEs were sufficient to maintain or improve shareholder value and
2 allowed utilities to issue additional equity without diluting existing investors.

3 **Q WHAT DID YOUR ANALYSIS OF THE HISTORICAL ERP SHOW?**

4 A Over the period studied, the ERP over U.S. Treasury bonds averaged 5.68% percent.
5 Five-year rolling averages ranged from 4.25% to 7.09%, while the ten-year rolling
6 average risk premium ranged from 4.38% to 6.91%, as shown in Exhibit AB-14. The
7 ERP over "A"-rated utility bonds averaged 4.33% over the same period, with five-year
8 rolling averages ranging from 2.88% to 5.91% and ten-year rolling averages ranging
9 from 3.20% to 5.74%, as shown in Exhibit AB-15.

10 **Q WHY IS THIS TIME PERIOD APPROPRIATE FOR ESTIMATING TODAY'S RISK**
11 **PREMIUM?**

12 A The period from 1986 to the present is long enough to capture a variety of economic
13 conditions while smoothing out temporary market distortions. It represents a sustained
14 era during which utilities traded above book value, demonstrating that authorized ROEs
15 were sufficient to meet investor expectations and to allow utilities to raise equity capital
16 on reasonable terms.

17 **Q WHAT OTHER MARKET EVIDENCE DID YOU CONSIDER?**

18 A I also examined the yield spread between utility bonds and Treasury bonds since 1980,
19 as shown in Exhibit AB-16. Historically, "A"-rated utility bonds have yielded 1.47% more
20 than Treasury bonds, while "Baa"-rated utility bonds have yielded 1.88% more.
21 Currently, the yield on "A"-rated utility bonds is 5.86% compared to 4.89% for long-term
22 Treasuries, a spread of 0.97%. The yield on "Baa"-rated utility bonds is 6.06% percent,

1 a spread of 1.17%. Both current spreads are below their respective long-term
2 averages, which indicates that investors presently view utilities as less risky than in the
3 past.

4 **Q HOW IS THE DECLINE IN UTILITY BOND SPREADS RELEVANT TO SETTING**
5 **ROE?**

6 A Narrower utility bond spreads mean that investors require less additional return for
7 assuming utility credit risk. Because the cost of equity should reflect prevailing market
8 conditions, a lower perceived level of credit risk supports a lower ERP and a lower
9 investor-required ROE. Maintaining an elevated ROE when market evidence shows
10 reduced risk would overcompensate utilities and unnecessarily increase rates for
11 customers. Bond spreads are a real-time, market-based measure of investor risk
12 perceptions and provide valuable input for setting a just and reasonable ROE.

13 **Q WHAT ERP DO YOU RECOMMEND?**

14 A The projected 30-year Treasury yield of 4.60% is consistent with the annual average
15 Treasury yields since 2023. Similarly, the recent average "A"-rated utility bond yield of
16 5.86% is also relatively consistent with the yields since 2023. In addition, utility bond
17 yield spreads have been below their long-term average since 2023, and remain as such
18 today. Intuitively, if bond yields are consistent with those of the recent past, and the
19 yield spreads continue to be below their long-term average over that same time period,
20 it makes sense then that the ERP would be also be consistent with the ERP over that
21 same time. As such, I recommend an ERP of 5.28% over Treasury bond yields and
22 an ERP of 4.06% over "A"-rated utility bond yields.

Q WHAT ARE THE RESULTS OF YOUR RISK PREMIUM ANALYSES?

A Adding my recommended ERP of 5.28% over Treasury bonds to the projected 30-year Treasury yield of 4.60% produces an ROE of 9.88%. Adding my recommended ERP of 4.06% over "A"-rated utility bond yields to the recent average "A"-rated utility bond yield of 5.86% results in a 9.92% ROE.

Q HAVE YOU PERFORMED AN ADDITIONAL RISK PREMIUM ANALYSIS?

A Yes, I have. In addition to the Risk Premium analysis above, I have also performed a weighted least squares ("WLS") regression analysis based on the same authorized ROEs, long-term Treasury bond yields, and corresponding ERP since 1986.

Q WHAT IS WLS REGRESSION, AND WHY DID YOU USE IT INSTEAD OF ORDINARY LEAST SQUARES ("OLS") REGRESSION?

A WLS regression is a variation of the traditional OLS regression method. Like OLS, it is used to estimate the relationship between variables such as the ERP and interest rates, but it improves on OLS by allowing certain observations to carry more influence than others based on their relevance or reliability.

OLS regression treats all data points equally, assigning the same weight to each observation regardless of when it occurred. This equal treatment can be problematic when analyzing long historical datasets, particularly when the relationship between variables like bond yields and ERP has evolved over time due to changing market conditions or regulatory environments. For example, an ROE authorized by a state commission in 1992 may have been based on vastly different economic, policy, and risk considerations than one authorized in 2024.

WLS regression addresses this by assigning greater weight to more recent data, which better reflects the current relationship between bond yields and the equity risk premium. In this analysis, I used an exponential weighting function that gradually reduces the influence of older data while emphasizing more recent observations. This approach helps ensure the regression model reflects contemporary market conditions more accurately, which is especially important for estimating the current cost of equity.

By using WLS, the goal is to produce a more relevant and timely estimate of the cost of equity for ratemaking purposes, one that better reflects today's utility environment rather than relying equally on data from decades ago that may no longer be representative of the current regulatory environment and economic conditions.

Q HOW ARE THE DATA POINTS WEIGHTED IN YOUR WLS REGRESSION, AND WHAT IS THE ROLE OF THE WEIGHTING PARAMETER LAMBDA (λ)?

A In my WLS regression, each historical observation is assigned a weight based on how recent it is. More recent data points are given more weight, while older data points are gradually given less influence. This approach reflects the view that recent authorized returns and interest rate conditions are more relevant for determining today's cost of equity than decisions made decades ago. The weights are assigned using an exponential decay function. Specifically, each observation's weight is calculated using the formula:

$$\text{Weight} = \exp(-\lambda \times (T - t))$$

where T is the most recent period, t is the year of the observation, and λ (lambda) is a decay factor that controls how quickly the influence of older data declines.

In my analysis, I used a lambda (λ) of 0.20.

Q WHY DID YOU SELECT A LAMBDA VALUE OF 0.20?

A Lambda values generally range from 0.0 to 1.0. If lambda is set equal to 0.0, the observations are weighted equally and similarly to OLS regression. If lambda is set to 1.0, virtually all observations except for the most recent are assigned zero weight. A lambda of 0.20 provides a reasonable balance. It places meaningful emphasis on the most recent 5 to 10 years of data, when regulatory policy and investor expectations have been shaped by modern factors like affordability concerns, decarbonization mandates, and alternative ratemaking mechanisms, while still retaining some influence from earlier periods. With this lambda value, observations from over 20 years ago are not completely disregarded but are weighted substantially less than those from recent years. A smaller lambda (e.g., 0.05) would allow outdated data to continue exerting significant influence, potentially diluting the accuracy of the model in current conditions. A larger lambda (e.g., 0.8) would disregard too much historical information, increasing volatility. The 0.20 value was chosen based on this tradeoff and where it demonstrated a strong statistical fit to the data.

Q IS WLS REGRESSION ONLY APPROPRIATE WHEN CORRECTING FOR HETEROSKEDASTICITY?

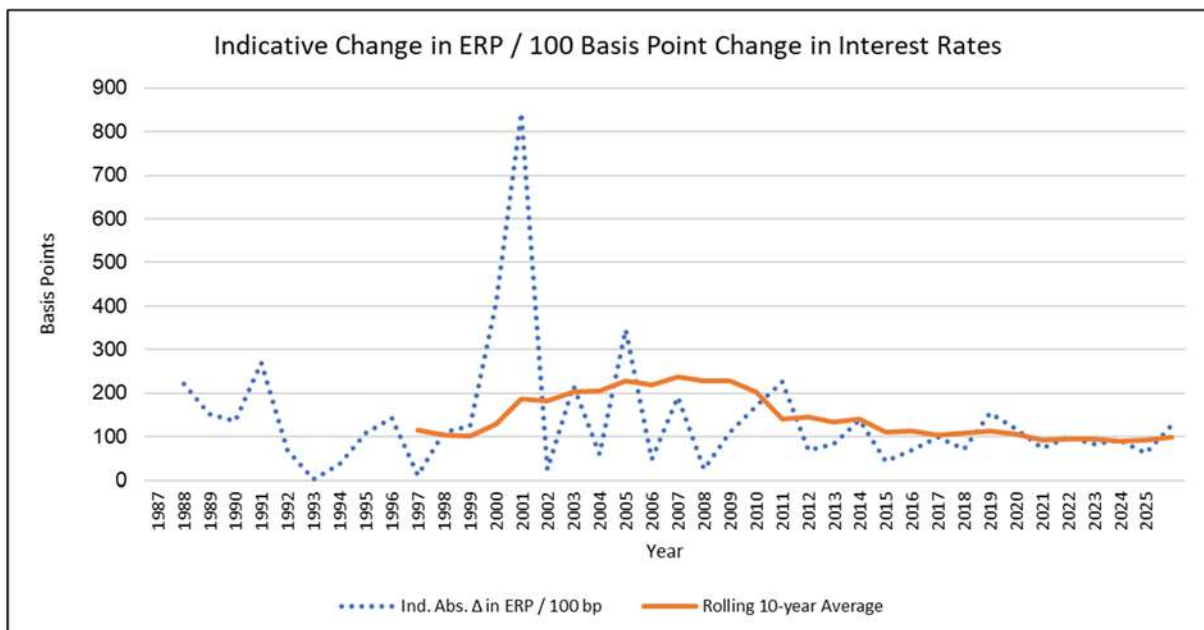
A No. While it is true that WLS is traditionally taught as a remedy for heteroskedasticity, its application is broader. For example, in a peer-reviewed article published in the Journal of Financial Markets (2021), Wang and Wu demonstrate that WLS with time-dependent weights significantly improves the forecasting of stock returns compared to OLS. The purpose of their weighting scheme was not to correct heteroskedasticity, but rather to address structural breaks and evolving relationships over time, giving more weight to more recent observations. This is directly relevant

here, because the equity risk premium and bond yield relationship has changed across economic cycles. In other words, WLS provides a disciplined way to allow more recent data, which reflect today's capital market environment, to carry more weight than very old observations, rather than assuming that all data points from 30+ years ago are equally relevant.

Q IS THERE EVIDENCE SHOWING THE RELATIONSHIP BETWEEN INTEREST RATES AND THE ERP IS EVOLVING?

A Yes. As shown below in Figure CCW-5, below illustrates the annual indicated change in the ERP per 100-basis-point change in interest rates (dotted line), along with the rolling 10-year average (solid line). The chart demonstrates that the relationship between interest rates and the ERP has not been stable over time. For example, the annual indicated change averages 139 basis points, but with a very wide standard deviation of 144 basis points. This volatility means that the sensitivity of ERP to interest rates has shifted considerably across different periods.

FIGURE CCW-5



A standard OLS regression gives equal weight to every observation in the dataset, which causes it to dilute or overlook structural changes in the relationship. By contrast, my WLS regression gives more weight to more recent data, allowing the analysis to adapt more quickly to evolving capital market conditions. This approach better reflects the current dynamics between interest rates and ERP rather than relying on outdated relationships that may no longer apply.

Q WHAT WERE THE RESULTS OF YOUR WLS REGRESSION ANALYSIS, AND WHAT DO THEY INDICATE ABOUT THE RELATIONSHIP BETWEEN INTEREST RATES AND THE ERP?

A As described above, I performed a WLS regression analysis to estimate the relationship between long-term U.S. Treasury bond yields and the ERP. In this analysis, the ERP was defined as the difference between the annual average authorized ROE and the corresponding annual average yield on long-term Treasury bonds. As described above, I applied exponential weights with a decay factor (lambda) of 0.20 to emphasize more recent years where regulatory and economic conditions are more consistent with current conditions. This gives greater influence to more recent data points while still retaining some information from earlier years.

The resulting regression model is:

$$\text{ERP} = 9.1365 - 0.8458 \times \text{Bond Yield}$$

The model achieved a very strong statistical fit, with an R-squared of 0.9409, indicating that approximately 94% of the variation in ERP is explained by changes in long-term bond yields under the WLS framework. Using a projected long-term Treasury bond yield of 4.60%, the WLS model produces a predicted ERP of:

$$\text{ERP} = 9.1365 - 0.8458 \times 4.60 = 5.25\%$$

1 Adding this ERP to the assumed bond yield yields an estimated cost of equity:

2 $ROE = 4.60\% + 5.25\% = 9.85\%$

3 This result reflects a cost of equity estimate that is consistent with current capital
4 market conditions, while giving appropriate weight to the most relevant regulatory data.
5 The high explanatory power of the model further supports its suitability for informing
6 ratemaking decisions.

7 The results of my risk premium analyses are summarized in Table CCW-8.

Table CCW-8	
<u>Summary of Risk Premium Results</u>	
<u>Description</u>	<u>Results</u>
Projected Treasury Yield	9.88%
<u>A-Rated Utility Bonds</u>	
3-Month Average Yields	9.92%
6-Month Average Yields	9.93%
WLS Regression	9.85%

8 **J. Capital Asset Pricing Model**

9 **Q PLEASE DESCRIBE THE CAPM.**

10 A The CAPM method of analysis is based upon the theory that the market-required ROR
11 for a security is equal to the risk-free rate, plus a risk premium associated with the
12 specific security. This relationship between risk and return can be expressed
13 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 stock'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%.¹⁸ The current 30-year Treasury bond yield is 4.89%, as shown in Exhibit AB-17 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 To ensure a more accurate and representative estimate of systematic risk, I have considered multiple approaches to beta estimation. This includes current published betas from *Value Line*, a long-term average of *Value Line* betas, three-year betas adjusted using *Value Line*'s methodology, and Vasicek-adjusted betas from S&P Capital IQ's Beta Generator Model.

As shown in Exhibit AB-18, the current proxy group average and median *Value Line* beta estimates are 0.75 and 0.75, respectively. The long-term average beta since 2014 is 0.78 and has ranged from 0.54 to 0.95. The three-year betas adjusted using *Value Line*'s methodology average 0.64 and have a median of 0.63.

The S&P Vasicek-adjusted betas, calculated using five years of weekly data ending September 12, 2025, average 0.42 and have a median of 0.41 for the proxy group. These betas use the S&P 500 as the benchmark market index, aligning with my use of the S&P 500 to estimate the expected market return. In contrast, *Value Line*'s betas use the NYSE Composite Index and apply a constant 67%/35% adjustment to the raw beta and market average, respectively. Because *Value Line*'s method does not account for the reliability of the underlying data, its betas can be overstated, particularly for low-volatility sectors like utilities. As S&P explains:

¹⁸*Blue Chip Financial Forecast*, August 29, 2025.

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 = $1/3 \times \text{market beta} + 2/3 \times \text{Raw Beta}$). 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.¹⁹

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.²⁰ 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.

Q WHY ARE THE VASICEK-ADJUSTED BETAS FROM S&P SIGNIFICANTLY LOWER THAN THE VALUE LINE BETAS IN YOUR ANALYSIS?

A The difference in beta estimates arises primarily from how each method addresses estimation error. The Vasicek method adjusts raw betas toward an industry-specific mean based on statistical accuracy, placing more weight on estimates with lower variance. For utilities, which typically exhibit low volatility and weaker correlation with the broader market, this often results in downward adjustments toward a beta range of

¹⁹S&P Market Intelligence, Beta Generator Model.

²⁰The 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).

1 approximately 0.4 to 0.6. *Value Line*'s approach, on the other hand, adjusts toward the
2 broader market mean of 1.0 regardless of the accuracy of the raw beta. Consequently,
3 the Vasicek method potentially better reflects the defensive characteristics of utility
4 stocks and provides a measure of systematic risk that is more reflective of actual risk.

5 **Q HOW DID YOU DERIVE YOUR MRP ESTIMATES?**

6 A My MRP estimates are derived using two general approaches: a risk premium
7 approach and a DCF approach. I also consider the normalized MRP of 5.50% with the
8 normalized risk-free rate of 4.85% as recommended by Kroll, formerly known as
9 Duff & Phelps.²¹ Based on this methodology and utilizing a "normalized" risk-free rate
10 of 4.85%, Kroll concludes that the current expected, or forward-looking, MRP is 5.50%,
11 implying an expected return on the market of 10.35%.²²

12 **Q PLEASE DESCRIBE YOUR MRP ESTIMATE DERIVED USING THE RISK PREMIUM**
13 **METHODOLOGY.**

14 A The forward-looking risk premium-based estimate was derived by estimating the
15 expected return on the market (as represented by the S&P 500) and subtracting the
16 risk-free rate from this estimate. I estimated the expected return on the S&P 500 by
17 adding an expected inflation rate to the long-term historical arithmetic-average real
18 return on the market. The real return on the market represents the achieved return
19 above the rate of inflation.

²¹Kroll, 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.

²²Kroll, Kroll Recommended U.S. Equity Risk Premium and Corresponding Risk-Free Rates to be Used in Computing Cost of Capital: January 2008 - Present (Apr. 15, 2025). The current 20-year yield of 4.85% 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., 4.85%.

Morningstar Direct calculates the historical arithmetic-average real-market return over the period 1926 to 2023 to be 9.02%.²³ A current consensus for projected inflation is 2.40%.²⁴ Using these estimates, the expected market return is 11.64%.²⁵ The MRP then is the difference between the 11.64% expected market return and the projected risk-free rate of 4.60%, or 7.00%.

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%.²⁶ The weighted average growth rate for the remaining companies is 11.00%. 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 12.58%. The MRP then is the expected market return of 12.58%, less the projected risk-free rate of 4.60%, or approximately 8.00%.

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

²³Morningstar Direct, data through 2023.

²⁴Blue Chip Financial Forecast, August 29, 2025.

²⁵ $[(1 + 9.02\%) * (1 + 2.40\%) - 1] * 100$.

²⁶Opinion No. 569-A, at 210.

1 rather than just the dividend-paying companies. The weighted average growth rate for
2 these companies is 11.20%. After reflecting the FERC-prescribed method of adjusting
3 the dividend yield by $(1 + 0.5g)$, the weighted average expected dividend yield is 1.37%.
4 Thus, the DCF-derived expected return on the market is the sum of those two
5 components, or 12.57%. The MRP then is the expected market return of 12.57% less
6 the projected risk-free rate of 4.60%, or approximately 8.00%.

7 The average expected market return based on the DCF model is 12.58% and
8 the average MRP based on the two DCF estimates is 8.00%.

9 **Q HOW DO YOUR EXPECTED MARKET RETURNS COMPARE TO CURRENT**
10 **EXPECTATIONS OF FINANCIAL INSTITUTIONS?**

11 **A** As shown in Table CCW-9, my average expected market return of 11.52%²⁷ exceeds
12 long-term market expectations of several financial institutions.

²⁷11.52% = $(10.35\% + 12.58\% + 11.64\%) / 3$.

TABLE CCW-9		
<u>Long-Term Expected Return on the Market</u>		
<u>Source</u>	<u>Term</u>	<u>Expected Return Large Cap Equities</u>
BlackRock Capital Management ¹	10 Years	6.70%
JP Morgan Chase ²	10 - 15 Years	6.70%
Vanguard ³	10 Years	2.8% - 4.8%
Research Affiliates ⁴	10 Years	3.92%
Invesco ⁵	10 Years	5.0% - 6.3%
Goldman Sachs ⁶	10 Years	3.00%
Fidelity ⁷	20 Years	5.70%
Schwab ⁸	10 Years	6.00%
Sources:		
¹ BlackRock Investment Institute, Capital market assumptions, May 22, 2025.		
² JP Morgan Chase, Long-Term Capital Market Assumptions, 2025 Report.		
³ Vanguard economic and market outlook for 2025: Beyond the Landing.		
⁴ Research Affiliates, Asset Allocation Interactive. Retrieved 4/30/2025.		
⁵ 2025 Invesco Capital Market Update.		
⁶ Goldman Sachs, Updating our long-term return forecast for US equities to incorporate the current high level of market concentration, October 18, 2024.		
⁷ Fidelity, Capital market assumptions		
⁸ Schwab's 2025 Long-Term Capital Market Expectations, January 3, 2025		

1 When compared to the expected market returns of financial institutions above,
2 my average expected market return of 11.52% is greater than all of them. For these
3 reasons, my expected market returns, and the associated MRPs, should be considered
4 reasonable, if not high-end estimates.

1 **Q HOW DO YOUR ESTIMATED MRPS COMPARE TO THAT ESTIMATED BY**
2 **KROLL?**

3 A On its Cost of Capital portal, Kroll's MRP falls somewhere in the range of 5.50%
4 to 7.17%. My MRP estimates are in the range of 5.50% to 8.00%.

5 **Q HOW DOES KROLL MEASURE A MRP?**

6 A Kroll's range is based on several methodologies. First, Kroll estimated a MRP of 7.17%
7 based on the difference between the total market return on common stocks (S&P 500)
8 less the income return on 20-year Treasury bond investments over the 1926-2023
9 period.²⁸

10 Second, Kroll used the Ibbotson & Chen supply-side model which produced a
11 MRP estimate of 6.22%.²⁹ Kroll explains that the historical MRP based on the S&P 500
12 was influenced by an abnormal expansion of P/E ratios relative to earnings and
13 dividend growth. To control for the volatility of extraordinary events and their impacts
14 on P/E ratios, Kroll takes into consideration the three-year average P/E ratio as the
15 current P/E ratio. Therefore, Kroll adjusted this MRP estimate to normalize the growth
16 in the P/E ratio to be more in line with the growth in dividends and earnings.

17 Finally, Kroll developed its own recommended equity risk premium, or MRP, by
18 employing an analysis that takes into consideration a wide range of economic
19 information, multiple risk premium estimation methodologies, and the current state of
20 the economy by observing measures such as the level of stock indices and corporate
21 spreads as indicators of perceived risk. Based on this methodology, and utilizing a

²⁸Kroll Cost of Capital Navigator.

²⁹*Id.*

1 “normalized” risk-free rate of 4.85%, Kroll concludes that the current expected, or
2 forward-looking, MRP is 5.50%, implying an expected return on the market of 10.35%.³⁰

3 **Q WHAT ARE THE RESULTS OF YOUR CAPM ANALYSIS?**

4 A As shown in Exhibit AB-19, I have provided the results of twelve different applications
5 of the CAPM. The first three results presented are based on the proxy group’s current
6 average *Value Line* beta of 0.75. The results of the CAPM based on these inputs range
7 from 8.99% to 10.62%.

8 The next set of three results presented are based on the proxy group’s historical
9 *Value Line* beta of 0.78. The results of the CAPM based on these inputs range from
10 9.16% to 10.88%.

11 The third set of results presented are based on the proxy group’s current *S&P*
12 *Global Market Intelligence* beta of 0.42. The results of the CAPM based on these inputs
13 range from 7.15% to 7.95%.

14 The final set of results presented are based on the proxy group’s three-year
15 beta estimate of 0.64. The results of the CAPM based on these inputs range from
16 8.35% to 9.69%.

17 My CAPM results are summarized in Table CCW-10.

³⁰Kroll, *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).

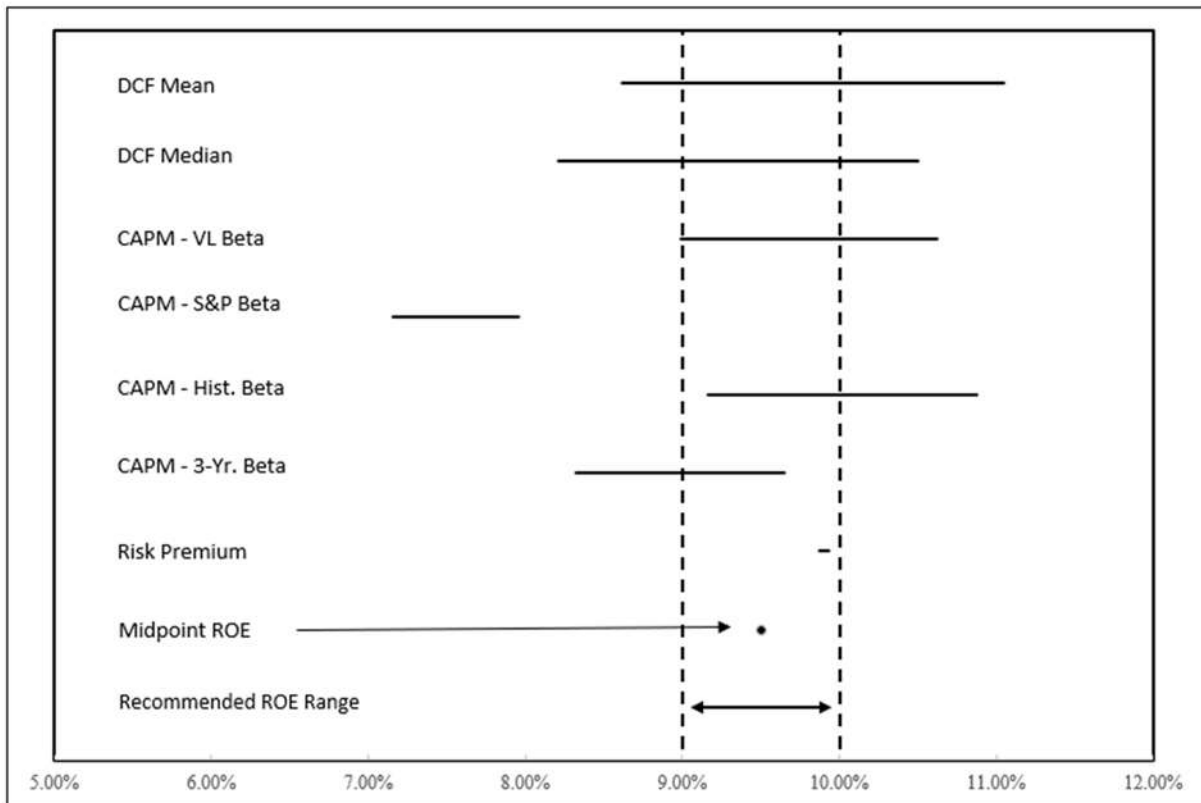
Table CCW-10				
<u>CAPM Results Summary</u>				
<u>Description</u>	<u>Current VL Beta</u>	<u>Historical VL Beta</u>	<u>Current S&P Beta</u>	<u>3-Year Beta</u>
Kroll Method	8.99%	9.16%	7.15%	8.35%
RP Method	9.87%	10.09%	7.53%	9.06%
FERC DCF Method	<u>10.62%</u>	<u>10.88%</u>	<u>7.95%</u>	<u>9.69%</u>
Average	9.83%	10.04%	7.54%	9.03%

1 **K. Return on Equity Summary**

2 **Q BASED ON THE RESULTS OF YOUR ANALYSIS DESCRIBED ABOVE, WHAT**
3 **ROE DO YOU RECOMMEND FOR CONSUMERS ENERGY?**

4 **A** The results of my analyses are summarized in Figure CCW-6. In this figure, I present
5 the various measures of central tendency (i.e., the mean and median results) for each
6 of my analytical models.

Figure CCW-6



Based on my analyses of the various methodologies described above, I estimate Consumers Energy's current market ROE to be in the reasonable range of 9.00% to 10.00%. As described above, the results of the constant growth DCF using analysts' growth rates assume an average long-term growth rate of 7.22%, which is approximately 77% higher than the long-term projected GDP growth rate of 4.09%. 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. Based on my assessment of Consumers Energy's lower overall risk profile, the results of these analytical methods, and taking into consideration the Company's existing ROE, I recommend that this Commission authorize Consumers Energy a ROE of 9.50%, which is the midpoint of the reasonable range of 9.00% to 10.00%. The midpoint

1 estimate of 9.50% is more than reasonable given Consumers Energy's relative risk
2 profile.

3 **V. RESPONSE TO MS. BULKLEY**

4 **A. Summary of Rebuttal to Ms. Bulkley**

5 **Q WHAT RETURN ON COMMON EQUITY IS THE COMPANY PROPOSING FOR THIS**
6 **PROCEEDING?**

7 A Ms. Bulkley recommends a range of 10.25% to 11.25% based on her market-based
8 model results. The Company is requesting an ROE of 10.25% which represents the
9 low-end of Ms. Bulkley's recommended range and represents a significant increase
10 from the Company's last approved ROE of 9.80% in Case No. U-21585.³¹

11 **Q PLEASE SUMMARIZE MS. BULKLEY'S RETURN ON EQUITY ESTIMATES.**

12 A Ms. Bulkley's return on equity estimates are summarized in Table CCW-11 below.
13 With prudent and reasonable adjustments to Ms. Bulkley's DCF, CAPM, and Risk
14 Premium return estimates, her studies show that my 9.50% recommended return on
15 equity for Consumers Energy is reasonable.

³¹Bulkley Direct at 5.

TABLE CCW-11

Bulkley's Return on Equity Estimates

Description		Bulkley Results¹		
<u>Constant Growth DCF (Mean)</u>		<u>Low</u>	<u>Mean</u>	<u>High</u>
30-Day Average		8.92%	10.24%	11.18%
90-Day Average		9.06%	10.38%	11.32%
180-Day Average		<u>9.16%</u>	<u>10.47%</u>	<u>11.42%</u>
DCF Average		9.05%	10.36%	11.31%
<u>Constant Growth DCF (Median)</u>		<u>Low</u>	<u>Median</u>	<u>High</u>
30-Day Average		9.47%	10.07%	10.77%
90-Day Average		9.62%	10.27%	10.88%
180-Day Average		<u>9.79%</u>	<u>10.43%</u>	<u>11.01%</u>
DCF Average		9.63%	10.26%	10.89%
		<u>30-Year Treasury Bond Yield</u>		
<u>CAPM DCF-Derived Results</u>		<u>Current Treasury</u>	<u>Near-Term Proj. Treasury</u>	<u>Long-Term Proj. Treasury</u>
Value Line		12.18%	12.18%	12.17%
Bloomberg		10.85%	10.83%	10.78%
LT Average		<u>10.85%</u>	<u>10.83%</u>	<u>10.79%</u>
CAPM Average		11.29%	11.28%	11.25%
ECAPM		0.1129% - 12.28%		
<u>Risk Premium</u>				
Current 30-Yr Treasury		10.67%		
Near-Term Projected 30-Yr Treasury		10.62%		
Long-Term Projected 30-Yr Treasury		<u>10.49%</u>		
Risk Premium Average		10.59%		
Recommended Range		10.25% - 11.25%		
Company Proposed ROE		10.25%		

Sources: ¹Bulkley A-14 (AEB-1), Schedule D-5, page 1.

- 1 I will discuss my concerns with each of her analytical methods and conclusions
- 2 below.

Q ARE MS. BULKLEY'S RETURN ON EQUITY ESTIMATES REASONABLE?

A No. Ms. Bulkley's estimated return on equity 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.

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 pages 3-5. 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 March 31, 2025. 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 5.19%, 6.48%, and 7.41%, respectively.³² Her average of her mean DCF results range from 9.05% to 11.31%. The average of her median DCF results range from 9.63% to 10.89%.

³²Exhibit No. A-14 (AEB-1), pages 3-5.

1 **Q ARE THE CONSTANT GROWTH DCF RESULTS PRODUCED BY MS. BULKLEY**
2 **REASONABLE?**

3 A No. Ms. Bulkley's results are overstated. As discussed regarding my own DCF study,
4 her consensus analysts' growth rates are substantially higher than the long-term
5 sustainable growth rate of 4.09% as described above. Specifically, Ms. Bulkley's
6 constant growth DCF model is based on growth rates of 5.19%, 6.48%, and 7.41%,
7 respectively. These growth rates exceed projected GDP growth, meaning even her
8 low-growth rate scenario produces potentially excessive results. As I discuss in greater
9 detail above, growth rates that exceed the growth rate of GDP in the country in which
10 the utility provides goods and services cannot be sustained. Therefore, her DCF model
11 results should be considered high-end return estimates. Given the fact that Ms.
12 Bulkley's average and Maximum-Growth scenarios assume an average growth rate of
13 6.48% and 7.41%, which exceed the consensus long-term projected growth rate of the
14 U.S. economy by 239 and 332 basis points, respectively, they should be given little
15 weight. Because of the economic infirmities with her assumed proxy company growth
16 rate that exceeds the expected growth of the US economy in perpetuity, Ms. Bulkley
17 should have considered the results of a multi-stage DCF.

18 As shown above in Table CCW-11, the midpoint of her average Low (9.05%)
19 and Mean (10.36%) growth constant growth DCF mean results is approximately 9.71%,
20 while the midpoint of her median Low (9.63%) and Mean (10.26%) growth constant
21 growth DCF mean results is approximately 9.94%. As shown on my Exhibit AB-12, the
22 average and median multi-stage DCF ROEs for my proxy group using the 13-week
23 average stock price are 8.62% and 8.21%. After considering the multi-stage model, a
24 DCF-based ROE well below 10.0% 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 rate of return 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:

$B_i \times (R_m - R_f)$ where:

B_i = Beta - Measure of the risk for stock

R_m = Expected return for the market portfolio

R_f = 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. Also, Ms. Bulkley's current five-year *Value Line* betas are likely overstated given that her analysis date was as of March 31, 2025, meaning at the time of her analysis, her *Value Line* betas were still being heavily impacted by the market's fallout, and resulting extraordinary volatility, due to the onset of a global pandemic in the first half of 2020.

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%, 8.06%, and 8.28% based on a

DCF market return of 12.58% less the current, near-term, and projected 30-year Treasury bond yields of 4.61%, 4.52%, and 4.30%, respectively.³³

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 12.58%, which consists of a weighted average growth rate component of 11.15% and weighted expected dividend yield of approximately 1.36%.³⁴ 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 11.15% 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 4.09%.

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.**³⁵

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

³³Exhibit No. A-14 (AEB-1), Schedule D-5, page 6-13.

³⁴*Id.* (12.58% = 1.36% x (1+0.5 x 11.15%) + 11.15%).

³⁵CFA 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).

1 supplemented her analysis with multiple approaches to estimating the market return,
2 as I have done.

3 **Q DO YOU HAVE ANY OTHER COMMENTS CONCERNING MS. BULKLEY'S CAPM**
4 **ANALYSIS?**

5 A Yes. Ms. Bulkley's CAPM analysis that relies on her current *Value Line* betas are
6 overstated as they are being heavily impacted by the market's fallout, and resulting
7 extraordinary volatility, due to the onset of a global pandemic in the first half of 2020.
8 This is easily demonstrated when comparing her proxy group's average current *Value*
9 *Line* beta of 0.95 to my proxy group's average *Value Line* beta of 0.75, a marked
10 decline of 21.1%.

11 **D. Ms. Bulkley's Empirical CAPM ("ECAPM") Studies**

12 **Q PLEASE DESCRIBE MS. BULKLEY'S ECAPM ANALYSIS.**

13 A Ms. Bulkley relies on empirical tests of the traditional CAPM model to modify it in such
14 a way to attempt to *correct* the original CAPM for some deficiencies inherent in the
15 original model. Empirical tests show that the expected return line, or security market
16 line, predicted by the CAPM are not as steep as the model would have us believe. In
17 other words, the traditional CAPM understates the expected return for securities with
18 betas less than 1, and overstates the expected return for securities with betas greater
19 than 1. In order to correct for this empirical finding, Ms. Bulkley modifies the traditional
20 CAPM model as follows:

1 $R_i = R_f + 0.75 \times B_i \times (R_m - R_f) + 0.25 \times B_m \times (R_m - R_f)$ where:

2 R_i = Required return for stock i
 3 R_f = Risk-free rate
 4 R_m = Expected return for the market portfolio
 5 B_m = Beta of the market
 6 B_i = Beta - Measure of the risk for stock

7 **Q WHAT ISSUES DO YOU TAKE WITH MS. BULKLEY'S ECAPM ANALYSIS?**

8 A The biggest issue I have with Ms. Bulkley's ECAPM analysis is her use of an adjusted
 9 beta as published by *Value Line*. The impact of Ms. Bulkley's ECAPM adjustments
 10 increases her adjusted beta estimate range of 0.783-0.95 to a range of 0.837-0.963.³⁶
 11 The weighting adjustments applied in the ECAPM are mathematically the same as
 12 adjusting beta since the inputs are all multiplicative as shown in the formula above.
 13 The result of both using adjusted betas and ECAPM is a flattening of the security
 14 market line.

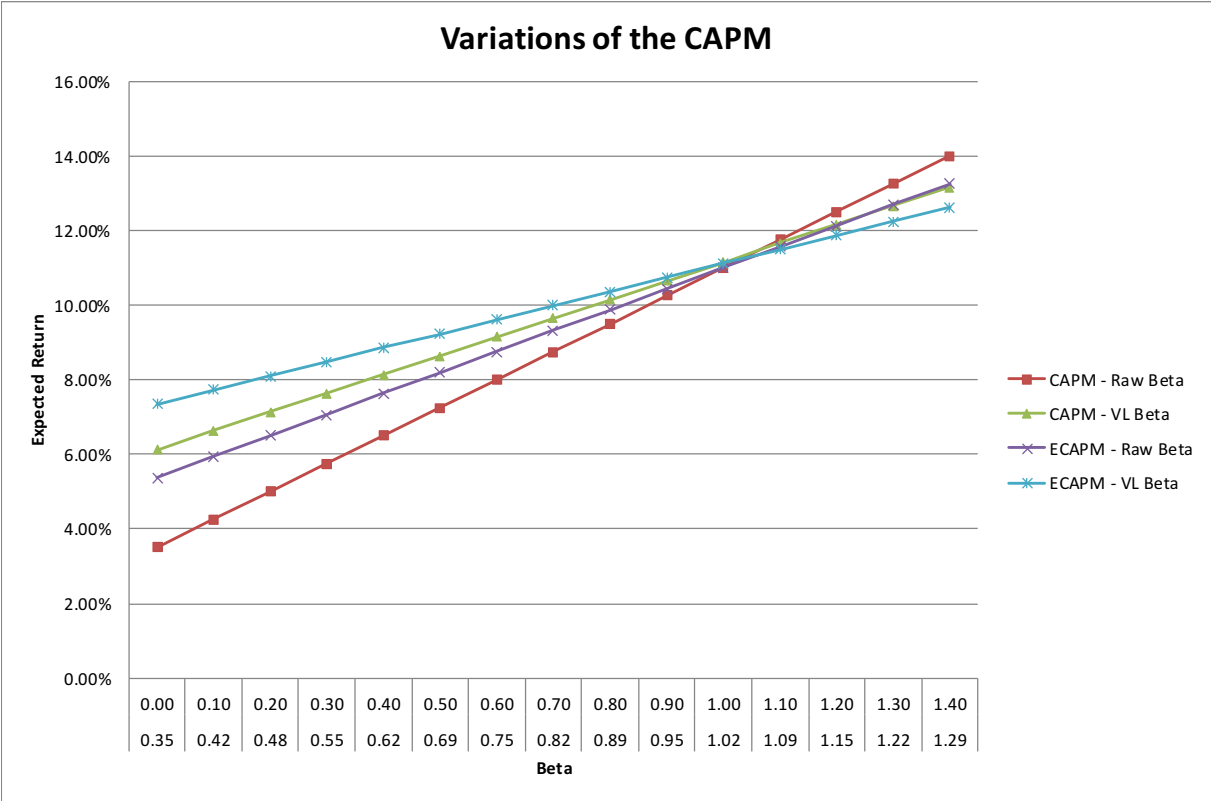
15 The end result of using adjusted betas in the ECAPM is an expected return line
 16 that has been flattened by two adjustments, meaning the vertical intercept has been
 17 raised twice and the security market line has been flattened twice: once through the
 18 adjustments *Value Line* made to the raw beta and again by weighting the risk-adjusted
 19 market risk premium as Ms. Bulkley has done.

20 In addition to the many adjustments employed by Ms. Bulkley, she further
 21 increases the intercept and flattens the security market line by using projected
 22 long-term Treasury yields.

³⁶75% x 0.783 + 25% x 1 = 0.837 and 75% x 0.95 + 25% x 1 = 0.963.

1 **Q CAN YOU DEMONSTRATE THE EFFECT VARIOUS ADJUSTMENTS SUCH AS**
2 **VALUE LINE BETAS AND THE ECAPM HAVE ON THE SECURITY MARKET LINE?**
3 A Yes. The ECAPM with adjusted betas has the effect of increasing CAPM return
4 estimates for companies with betas less than 1 and decreasing the CAPM return
5 estimates for companies with betas greater than 1. I have modeled the expected return
6 line resulting from the application of the various forms of the CAPM/ECAPM below in
7 Figure CCW-7.

FIGURE CCW-7



8 Along the horizontal axis in Figure CCW-7 above, I have provided the raw
9 unadjusted beta (top row) and the corresponding adjusted *Value Line* beta (bottom
10 row). As shown in Figure CCW-7 above, the CAPM using a *Value Line* beta compared
11 to the CAPM using an unadjusted beta shows that the *Value Line* beta raises the
12 intercept point and flattens the slope of the security market line. As shown in the figure

1 above, the two variations with the most similar slope are the CAPM with the *Value Line*
2 beta, and the ECAPM with a raw beta.

3 This evidence shows that the ECAPM adjustment has a very similar impact on
4 the expected return line as a *Value Line* beta. Another observation that can be made
5 from the figure above is the magnifying effect that the ECAPM using a *Value Line* beta
6 has on raising the vertical intercept and flattening the slope relative to all other
7 variations. There is simply no legitimate basis to use an adjusted beta within an
8 ECAPM because it unjustifiably alters the security market line and materially inflates a
9 CAPM return for a company with a beta less than 1.

10 **Q IN YOUR EXPERIENCE, IS MS. BULKLEY'S PROPOSED USE OF AN ADJUSTED**
11 **BETA IN AN ECAPM STUDY WIDELY ACCEPTED IN REGULATED UTILITY RATE**
12 **PROCEEDINGS SUCH AS THIS?**

13 A No. In my experience, regulatory commissions generally disregard the use of the
14 ECAPM, particularly when an adjusted beta is used in the model. For example, the
15 Illinois Commerce Commission has stated the following regarding the ECAPM:

16 The Commission cannot recall a proceeding in which it relied upon the
17 ECAPM in establishing the cost of common equity for a utility. In the
18 instant proceeding, the record supports a finding that use of adjusted
19 betas in the ECAPM is inappropriate. As Staff witness Ms. Freely
20 explained, by using adjusted betas she already effectively transformed
21 her Traditional CAPM into an ECAPM. Therefore, including an
22 additional beta adjustment in the ECAPM model would result in inflated
23 estimates of the samples' cost of common equity.³⁷

24 Similarly, the California Public Utilities Commission has stated "We are not
25 persuaded that ECAPM produces a result that should be considered. Electric utilities
26 in general have low betas. Adjusting betas upward guarantees a higher ROE."³⁸

³⁷Illinois-American Water Company, ICC Order Docket No. 11-0767, at page 109, September 19, 2012).

³⁸<https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M344/K961/344961040.PDF>.

1 In addition, I am unaware of an instance where this Commission has recently
2 accepted an ECAPM as presented by Ms. Bulkley.

3 Therefore, the Commission should reject Ms. Bulkley's ECAPM, which as
4 described above is based on adjusted beta estimates.

5 **E. Ms. Bulkley's Bond Yield Risk Premium ("BYRP")**

6 **Q PLEASE DESCRIBE MS. BULKLEY'S BYRP METHODOLOGY.**

7 A As shown on her Exhibit No. A-14 (AEB-1), Schedule D-5 pages 22-25, Ms. Bulkley
8 constructs a risk premium return on equity estimate based on the premise that equity
9 risk premiums are inversely related to interest rates. She estimates the average equity
10 risk premiums of approximately 5.44% over the period January 1980 through March
11 2025. She performs a linear regression using the 30-Year Treasury yield as the
12 independent variable (x-axis) and the risk premium as the dependent variable (y-axis).
13 This model produces a regression formula, which she applies by inputting the current,
14 near-term, and long-term projected 30-year Treasury bond yields of 4.61%, 4.52%, and
15 4.30%, respectively. The resulting expected equity risk premiums based on these
16 inputs are 6.06%, 6.10%, and 6.19%, respectively. She then adds these estimated risk
17 premiums to their corresponding levels of interest rates to produce electric return on
18 equity estimates of 10.67%, 10.62%, and 10.49%, respectively. The average of her
19 three BYRP return estimates is 10.59%.

20 **Q IS MS. BULKLEY'S BYRP METHODOLOGY REASONABLE?**

21 A No. To begin with, even though her analysis is predicated on authorized ROEs as the
22 starting point, her average BYRP result of 10.59 %exceeds every one of the 91 ROEs

1 awarded to electric utilities since 2024. This simple fact highlights the implausibility of
2 her model's outputs.

3 More importantly, Ms. Bulkley's regression framework is not dynamic enough
4 to capture how the relationship between interest rates and the ERP has evolved over
5 time. Her OLS approach gives equal weight to data going back to the 1980s, even
6 though regulatory practices, risk perceptions, and market structures have materially
7 changed in more recent years. As a result, her model extrapolates a higher ERP than
8 is consistent with recent experience. For example, she projects ERPs of 6.06% to
9 6.19%, even though the most recent four quarterly average ERPs observed in 2024–
10 2025 ranged from 5.11% to 5.65% percent at very similar levels of interest rates.

11 In a report issued last year, Regulatory Research Associates (a division of S&P
12 Global) discussed the equity risk premium, as measured by the authorized ROE spread
13 over bond yields as follows:

14 However, with the uptick in interest rates since 2020, the spread has
15 begun to narrow, falling to around 550 basis points in 2023. With the
16 myriad factors putting upward pressure on customer bills, the spread
17 may continue to narrow as regulators may become more reluctant to
18 raise authorized returns.³⁹

19 By contrast, my WLS analysis accounts for structural changes in the
20 ERP/interest rate relationship by assigning greater weight to more recent observations.
21 This makes WLS a more robust tool for capturing current capital market conditions.
22 Regulatory Research Associates has observed that the spread between authorized
23 ROEs and bond yields has narrowed as interest rates have risen, reflecting increased
24 attention to affordability and changing regulatory dynamics. This real-world evidence is
25 consistent with my WLS results—and inconsistent with Ms. Bulkley's static OLS model.
26 Therefore, Ms. Bulkley's BYRP analysis should be given little weight.

³⁹RRA, Major energy rate case decisions in the US January-December 2023 Quarterly update on decided rate cases, February 6, 2024. (Emphasis Added).

1 **Q** **DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?**

2 **A** Yes, it does.

Qualifications of Christopher C. Walters

1 **Q PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.**

2 A Christopher C. Walters. My business address is 16690 Swingley Ridge Road,
3 Suite 140, Chesterfield, MO 63017.

4 **Q PLEASE STATE YOUR OCCUPATION.**

5 A I am a consultant in the field of public utility regulation and a Principal with the firm of
6 Brubaker & Associates, Inc. ("BAI"), energy, economic and regulatory consultants.

7 **Q PLEASE STATE YOUR EDUCATIONAL BACKGROUND AND PROFESSIONAL**
8 **EMPLOYMENT EXPERIENCE.**

9 A I received a Bachelor of Science Degree in Business Economics and Finance from
10 Southern Illinois University Edwardsville. I have also received a Master of Business
11 Administration Degree from Lindenwood University.

12 As a Principal at BAI, I perform detailed technical analyses and research to
13 support regulatory projects including expert testimony covering various regulatory
14 issues. Since my career at BAI began in 2011, I have held the positions of Analyst,
15 Associate Consultant, Consultant, Senior Consultant, and Associate. Throughout my
16 tenure, I have been involved with several regulated projects for electric, natural gas
17 and water and wastewater utilities, as well as competitive procurement of electric power
18 and gas supply. My regulatory project work includes estimating the cost of equity
19 capital, capital structure evaluations, assessing financial integrity, merger and
20 acquisition related issues, risk management related issues, depreciation rate studies,
21 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 Requests for Proposal 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 Federal Energy Regulatory Commission ("FERC").

1 **Q PLEASE DESCRIBE ANY PROFESSIONAL REGISTRATIONS OR**
2 **ORGANIZATIONS TO WHICH YOU BELONG.**

3 A I earned the Chartered Financial Analyst (“CFA”) designation from the CFA Institute.
4 The CFA charter was awarded after successfully completing three examinations which
5 covered the subject areas of financial accounting and reporting analysis, corporate
6 finance, economics, fixed income and equity valuation, derivatives, alternative
7 investments, risk management, and professional and ethical conduct. I am a member
8 of the CFA Institute and the CFA Society of St. Louis.

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1 MR. CAMPBELL: Thank you, Your Honor.

2 Mr. Andrews pre-filed rebuttal testimony
3 consists of a cover page, a table of contents, 10 pages of
4 questions and answers, along with his rebuttal testimony.
5 Mr. Andrews sponsored Exhibit AB-20.

6 JUDGE THOITS: Are there any objections to the
7 admission of this testimony with this exhibit?

8 Hearing none. Rebuttal testimony of Brian
9 Andrews is bound in the record and exhibit AB-20 is
10 admitted.

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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 generation and distribution of)
 electricity and for other relief.)

Case No. U-21870

Rebuttal Testimony and Exhibit of

Brian C. Andrews

On behalf of

Association of Businesses Advocating Tariff Equity

October 21, 2025



Project 11862

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	)	Case No. U-21870
the generation and distribution of	)	
electricity and for other relief.	)	
	)	

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APPENDIX A: Qualifications of Brian C. Andrews

Exhibit AB-20: Case No. U-21870, Consumers Response to Data Request 21870-AB-CE-0757-0759.

**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	)	Case No. U-21870
the generation and distribution of	)	
electricity and for other relief.	)	
	)	

Rebuttal Testimony of Brian C. Andrews

I. INTRODUCTION

1

2 **Q PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.**

3 A Brian C. Andrews. My business address is 16690 Swingley Ridge Road, Suite 140,
4 Chesterfield, MO 63017.

5 **Q WHAT IS YOUR OCCUPATION?**

6 A I am a consultant in the field of public utility regulation and a Principal with the firm of
7 Brubaker & Associates, Inc. ("BAI"), energy, economic and regulatory consultants.

8 **Q PLEASE DESCRIBE YOUR EDUCATIONAL BACKGROUND AND EXPERIENCE.**

9 A This information is included in Appendix A to my testimony.

10 **Q ON WHOSE BEHALF ARE YOU APPEARING IN THIS PROCEEDING?**

11 A I am appearing on behalf of the Association of Businesses Advocating Tariff
12 Equity ("ABATE"). ABATE consists of large usage customers that purchase substantial
13 amounts of electric power and/or delivery service from Consumers Energy

Company ("Consumers" or "Company"). They primarily take service under Consumers' Rate GPD, Rate GPTU, Rate EIP, Rate GP, Rate GSG-2, and/or Rate LTILRR.

Q WHAT IS THE PURPOSE OF YOUR REBUTTAL TESTIMONY?

A The purpose of my Rebuttal Testimony is to respond to the Direct Testimony of Ms. Caroline Palmer whose positions have been sponsored by the Michigan Environmental Council ("MEC"), Natural Resources Defense Council ("NRDC"), and Citizens Utility Board of Michigan ("CUB"). Specifically, I will respond to Ms. Palmer's allocation proposal for certain distribution assets.

II. REBUTTAL OF CAROLINE PALMER

Classification of AMI Meters

Q WHAT IS YOUR UNDERSTANDING OF MS. PALMER'S PROPOSAL REGARDING THE CLASSIFICATION OF ADVANCED METERING INFRASTRUCTURE (AMI) METER COSTS?

A Ms. Palmer recommends changing the Company's current approach of classifying AMI meters as 100% customer related. She proposes dividing these costs among customer, demand, and energy components based on an allocation of 47% customer, 17% demand, and 36% energy.¹

¹ Direct Testimony of Caroline Palmer at page 9, lines 13-15.

Q DO YOU AGREE WITH MS. PALMER'S RECOMMENDATION TO RECLASSIFY AMI METER COSTS?

A No. The Company's current treatment of AMI meters as entirely customer-related is correct and consistent with cost-causation principles and long-standing Commission precedent.

Q WHY SHOULD AMI METERS CONTINUE TO BE CLASSIFIED AS 100% CUSTOMER-RELATED?

A Every customer, regardless of their size or usage pattern, must have a meter to receive service and be billed accurately. The cost of metering is caused by the existence of the customer relationship, not by how much energy the customer consumes or demands at peak. AMI technology does not change this fundamental causation, it merely provides an updated means of measuring and communicating customer usage. The Michigan Public Service Commission has repeatedly approved classifying meters as customer-related, including Consumers' AMI investments, and there is no new record evidence to justify departing from this standard.

Q MS. PALMER SUGGESTS THAT AMI METERS PRODUCE SYSTEM LEVEL ENERGY AND DEMAND BENEFITS THAT JUSTIFY SHARED COST ALLOCATION. HOW DO YOU RESPOND?

A First, a fundamental principle of cost allocation is the concept of cost-causation, meaning customers should be allocated the costs they cause. Allocating costs based on alleged benefits to various customer classes conflicts with this principle. Second, while AMI systems provide some operational benefits, those benefits are incidental and system wide, not direct drivers of metering costs. The purpose and function of the

1 meters remain customer specific, to measure consumption and support billing. Any
2 secondary energy or demand benefits are properly captured in operational savings and
3 not in the classification of the meter plant itself.

4 Exhibit AB-20, provides' Consumers response to discovery regarding the AMI
5 meter issue and demonstrates that residential customers have 1,716,384 AMI meters
6 installed, Commercial customers have 233,462 AMI meters installed, and the Primary
7 Rate Schedule GP only has 690 AMI meters installed. Therefore, the residential
8 customers represent 88.00% of the installed AMI meters, Commercial represents
9 11.97% and Primary represents just 0.04%. Only 690 of Consumers' industrial
10 customers that are on Rate Schedule GP use AMI meters. Not a single customer that
11 takes service under Rate Schedules GPD, GPTU, or EIP uses an AMI meter, meaning
12 they do not cause this cost.

13 Furthermore, any alleged benefits from AMI meter usage will go to the
14 customers and classes that use them. If there are energy savings from the knowledge
15 that an AMI meter provides, then the customer will see immediate savings on monthly
16 bills, via reduced consumption. If a customer uses AMI information to reduce their peak
17 demand, savings could be immediate or long-term. If a customer has a demand charge
18 billing component and they reduce their peak demand, then they will see that savings
19 on their monthly bill. If peak demand reduction is large enough for the overall class,
20 then that customer's class will see a reduced share of allocated costs in future rate
21 cases. The Primary customers represent essentially 0% of the AMI meters, therefore,
22 in general, the Primary customer classes neither cause these costs, nor will they see
23 any benefits from AMI. More specifically, Rate Schedules GPD, GPTU, and EIP do not
24 use AMI meters, therefore, they do not cause these costs, nor do they realize any
25 benefit from them being used by customers in other classes.

1 **Q WOULD ADOPTING MS. PALMER’S PROPOSAL IMPROVE COST RECOVERY**
2 **ACCURACY OR FAIRNESS AMONG CUSTOMER CLASSES?**

3 A No. Her proposed hybrid classification would introduce subjective weighting and
4 reduce transparency, making results dependent on assumptions about unquantified
5 benefits. It would also shift costs away from residential and commercial customers and
6 onto Primary customers without any engineering or economic evidence that those
7 customers cause or avoid meter costs differently. Maintaining the customer-based
8 allocator ensures fairness and regulatory consistency. Ms. Palmer’s proposal would
9 unfairly shift approximately \$59.5 million of AMI meter costs to the Primary Customer
10 classes which neither cause nor benefit from these costs.

11 **Allocation of Distribution Plant**

12 **Q WHAT CHANGES DOES MS. PALMER RECOMMEND REGARDING**
13 **DISTRIBUTION COSTS?**

14 A Ms. Palmer recommends rejecting the Company’s voltage differentiated allocation of
15 distribution costs. She claims that increased distributed generation has created
16 bidirectional power flows such that higher voltage customers benefit from or use
17 portions of the lower-voltage system.²

18 **Q DO YOU AGREE WITH MS. PALMER’S POSITION ON VOLTAGE**
19 **DIFFERENTIATION?**

20 A No. Ms. Palmer provides no engineering analysis, empirical data, or system studies to
21 demonstrate that higher voltage customers actually use, depend upon, or benefit from

² Direct Testimony of Caroline Palmer at page 17, lines 10-18.

1 the lower-voltage distribution network. The Company's allocation method is properly
2 based on physical use of facilities and voltage level of service, which are the true cost
3 drivers.

4 **Q WHY IS VOLTAGE BASED COST ALLOCATION THE CORRECT APPROACH?**

5 A Distribution facilities are planned, built, and operated to serve customers connected at
6 specific voltage levels. High-voltage customers are served upstream of the low-voltage
7 system and do not utilize those facilities; therefore, they do not cause the associated
8 costs. The Company's Electric Asset Categorization ("EAC") system improves
9 accuracy by mapping actual plant investments to their voltage level of use.³ Assigning
10 low-voltage system costs to high-voltage customers would distort cost responsibility
11 and create cross-subsidies that violate the cost-causation principle.

12 **Q MS. PALMER ARGUES THAT BIDIRECTIONAL POWER FLOWS FROM**
13 **DISTRIBUTED GENERATION UNDERMINE TRADITIONAL VOLTAGE BASED**
14 **COST ALLOCATION. DO YOU AGREE?**

15 A No. While distributed generation can cause limited instances of reverse flow at the
16 local level, neither Ms. Palmer nor Consumers have presented any evidence that such
17 flows are significant or system-wide. The Company itself is still developing analytical
18 tools to measure the extent of bidirectional flow.⁴ Until measurable data demonstrates
19 that higher-voltage customers are materially served by lower-voltage assets, the
20 long-established allocation method should remain unchanged.

³ Direct Testimony of Megan L. Hayward at pages 177-180 and Exhibit A-111 (MLH-5).

⁴ Exhibit MEC-17.

1 **Q HAS MS. PALMER PROVIDED ANY QUANTITATIVE ANALYSIS SUPPORTING**
2 **HER CLAIM THAT HIGH-VOLTAGE CUSTOMERS BENEFIT FROM**
3 **LOWER-VOLTAGE FACILITIES?**

4 **A**No. Ms. Palmer offers no quantitative study, system model, or power flow analysis
5 showing any measurable benefit or usage. Her argument rests on general assertions
6 about the potential future effects of distributed energy resources, not on actual
7 engineering evidence from the Company's system.

8 **Q WHAT WOULD BE THE RESULT IF THE COMMISSION ADOPTED MS. PALMER'S**
9 **RECOMMENDED CHANGES?**

10 **A**Adopting her proposals would improperly shift costs away from the low-voltage
11 residential and commercial customers which cause them and on to higher-voltage
12 commercial and industrial customers, despite those higher-voltage customers requiring
13 no use of the lower-voltage distribution system. This would contradict the core principle
14 that customers should pay the costs they cause to be incurred.

15 **Allocation of Distribution Batteries**

16 **Q WHAT IS MS. PALMER'S RECOMMENDATION REGARDING THE ALLOCATION**
17 **OF DISTRIBUTION BATTERY COSTS?**

18 **A**Ms. Palmer recommends that Consumers allocate the costs of distribution batteries to
19 all distribution customers, regardless of voltage level. She argues that these batteries
20 provide system-wide benefits such as capacity deferral, voltage support, and resiliency,
21 and therefore should not be assigned only to low-voltage customers.⁵

⁵ Direct Testimony of Caroline Palmer at page 18, lines 4-15.

Q DO YOU AGREE WITH MS. PALMER'S RECOMMENDATION TO ALLOCATE DISTRIBUTION BATTERY COSTS TO ALL CUSTOMERS?

A No. Ms. Palmer's recommendation lacks both engineering evidence and analytical support. The Company's treatment of these costs as LVD is correct because the batteries currently in service are physically connected to, and operate within, the low-voltage portion of the distribution system. The customers who are served from these circuits are the ones who directly cause these costs and benefit from these assets.

Q WHY IS IT APPROPRIATE TO ALLOCATE DISTRIBUTION BATTERY COSTS ONLY TO LOW-VOLTAGE CUSTOMERS?

A The batteries are installed specifically to support local circuits, address local reliability or voltage issues, and manage load on low-voltage feeders. These assets are not part of the transmission or high-voltage system used by Primary customers. The benefits are localized to the circuits where the batteries are deployed. Allocating those costs to customers who do not physically or operationally use those facilities would violate the cost-causation principle.

Q MS. PALMER CLAIMS THAT CONSUMERS HAS NOT PROVIDED EVIDENCE THAT BATTERIES SERVE ONLY LOWER-VOLTAGE CUSTOMERS. HOW DO YOU RESPOND?

A Consumers has documented that its distribution batteries are connected at voltages between 8.32 kV and 24.9 kV, which are classified as low-voltage distribution. These facilities are deployed to support the electric distribution system at those voltage levels.

1 The absence of a published manual does not negate the fact that these assets are not
2 serving higher-voltage or transmission level customers.⁶

3 **Q DOES MS. PALMER PROVIDE ANY SYSTEM ANALYSIS OR COST EVIDENCE**
4 **SHOWING THAT HIGH-VOLTAGE CUSTOMERS BENEFIT FROM THESE**
5 **LOW-VOLTAGE BATTERIES?**

6 A No. Ms. Palmer provides no quantitative analysis, modeling, or engineering study
7 demonstrating that high voltage or Primary customers receive measurable benefits
8 from the Company's distribution batteries. Her recommendation is based on general
9 assertions about potential system benefits, not on actual data or operational evidence.

10 **Q COULD ALLOCATING BATTERY COSTS TO ALL CUSTOMERS CAUSE COST**
11 **SHIFTING AMONG CLASSES?**

12 A Yes. If battery costs were spread across all distribution customers, Primary customers,
13 who do not use these low-voltage assets, would be forced to pay for facilities installed
14 to serve other parts of the system. This would unfairly shift costs away from the
15 customers who actually cause (and benefit from) those investments, violating
16 cost-causation principles and creating cross-subsidies among classes.

⁶ Exhibit MEC-18.

III. CONCLUSION

Q PLEASE SUMMARIZE YOUR OVERALL CONCLUSIONS REGARDING MS. PALMER'S PROPOSALS ON METERS, DISTRIBUTION PLANT, AND DISTRIBUTION BATTERIES.

A Ms. Palmer's recommendations to reclassify AMI meters, revise voltage-based distribution allocations, and spread distribution battery costs across all customers should be rejected in their entirety. Each proposal departs from established cost-causation principles, lacks quantitative or engineering evidence, and would improperly shift costs away from customers who actually cause (and benefit from) these investments. Consumers' existing methods of classifying meters as 100% customer-related, allocating distribution costs by voltage level of service, and assigning distribution battery costs to the low-voltage customers served by those assets are consistent with system design, regulatory precedent, and fairness among customer classes. The Commission should therefore maintain the current allocation practices and reject all of Ms. Palmer's proposed changes.

Q DOES THIS CONCLUDE YOUR REBUTTAL TESTIMONY?

A Yes, it does.

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Qualifications of Brian C. Andrews

1 **Q PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.**

2 A Brian C. Andrews. My business address is 16690 Swingley Ridge Road, Suite 140,
3 Chesterfield, MO 63017.

4 **Q PLEASE STATE YOUR OCCUPATION.**

5 A I am a consultant in the field of public utility regulation and a Principal with the firm of
6 Brubaker & Associates, Inc. ("BAI"), energy, economic and regulatory consultants.

7 **Q PLEASE STATE YOUR EDUCATIONAL BACKGROUND AND PROFESSIONAL**
8 **EMPLOYMENT EXPERIENCE.**

9 A I received a Bachelor of Science Degree in Electrical Engineering from the Washington
10 University in St. Louis/University of Missouri - St. Louis Joint Engineering Program. I
11 have also received a Master of Science Degree in Applied Economics from Georgia
12 Southern University.

13 I have attended training seminars on multiple topics including class cost of
14 service, depreciation, power risk analysis, production cost modeling, cost-estimation
15 for transmission projects, transmission line routing, MISO load serving entity
16 fundamentals and more.

17 I am a member and a former President of the Society of Depreciation
18 Professionals. I have been awarded the designation of Certified Depreciation
19 Professional ("CDP") by the Society of Depreciation Professionals. I am also a certified
20 Engineer Intern in the State of Missouri.

21 As a Principal at BAI, and as an Associate, Senior Consultant, Consultant,
22 Associate Consultant and Assistant Engineer before that, I have been involved with

1 several regulated and competitive electric service issues. These have included book
2 depreciation, fuel and purchased power cost, transmission planning, transmission line
3 routing, resource planning including renewable portfolio standards compliance, electric
4 price forecasting, class cost of service, power procurement, and rate design. This has
5 involved use of power flow, production cost, cost of service, and various other analyses
6 and models to address these issues, utilizing, but not limited to, various programs such
7 as Strategist, RealTime, PSS/E, MatLab, R Studio, ArcGIS, Excel, and the United
8 States Department of Energy/Bonneville Power Administration's Corona and Field
9 Effects ("CAFÉ") Program. In addition, I have received extensive training on the
10 PLEXOS Integrated Energy Model and the EnCompass Power Planning Software. I
11 have provided testimony on many of these issues before the Public Service
12 Commissions in Arizona, Arkansas, California, Colorado, Florida, Illinois, Indiana,
13 Kansas, Kentucky, Louisiana, Michigan, Minnesota, Missouri, Montana, New Mexico,
14 Oklahoma, South Carolina, Texas, Virginia, and Washington DC.

15 BAI was formed in April 1995. BAI provides consulting services in the
16 economic, technical, accounting, and financial aspects of public utility rates and in the
17 acquisition of utility and energy services through RFPs and negotiations, in both
18 regulated and unregulated markets. Our clients include large industrial and institutional
19 customers, some utilities and, on occasion, state regulatory agencies. We also prepare
20 special studies and reports, forecasts, surveys and siting studies, and present seminars
21 on utility-related issues.

22 In general, we are engaged in energy and regulatory consulting, economic
23 analysis and contract negotiation. In addition to our main office in St. Louis, the firm
24 also has branch offices in Corpus Christi, Texas; Louisville, Kentucky and Phoenix,
25 Arizona.

1 MR. CAMPBELL: At this time, I'd also move,
2 pursuant to the consent, not objection of the parties, for
3 admission of Exhibits AB-21 and AB-22. Exhibit AB-21
4 includes certain discovery responses from Consumers
5 Energy, along with the public attachments to those
6 responses. And Exhibit AB-22 is a confidential exhibit,
7 which includes the confidential attachments to the
8 relevant discovery responses. Included in Exhibit AB-21.

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

11 Hearing none. AB -- Exhibit AB-21 is admitted
12 to the public record, and Exhibit AB-22 is admitted in the
13 confidential record.

1 MR. CAMPBELL: Thank you, Your Honor. That's
2 all for ABATE.

3 JUDGE THOITS: Thank you. Mr. Bzdok, would you
4 hear to bind in?

5 MR. BZDOK: Yes, Your Honor. I'd be happy to do
6 so. At this time, on behalf of some or all of the MEC,
7 NRDC, Sierra Club, and CUB parties, which I will specify
8 for each witness. I would first bind in on behalf of MEX
9 and NRDC, the direct testimony of Scott Reeves, which
10 consists of a cover page, a table of contents, 36 pages of
11 questions and answers, and I'd move to admit into the
12 record Exhibits MEC-1 through MEC-3.

13 JUDGE THOITS: Are there any objections to the
14 admission to this testimony or these exhibits?

15 Hearing none. The direct testimony of Scott
16 Reeves is bound into the record, and exhibits MEC-1
17 through MEC-3 are admitted.

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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 U-21870
generation and distribution of electricity and
for other relief.

DIRECT TESTIMONY OF SCOTT REEVES**ON BEHALF OF****MICHIGAN ENVIRONMENTAL COUNCIL AND
NATURAL RESOURCES DEFENSE COUNCIL****September 26, 2025**

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1 **I. INTRODUCTIONS AND QUALIFICATIONS**

2 **Q. Please state your name, employer and business address.**

3 A. My name is Scott Reeves. I am a Managing Consultant of Energy Futures Group (EFG), a
4 consulting firm that provides specialized expertise on energy efficiency, demand response,
5 renewable energy, strategic electrification and other clean energy markets, programs and
6 policies. My business address is P.O. Box 587, Hinesburg, VT 05461.

7 **Q. On whose behalf is this testimony being offered?**

8 A. I am testifying on behalf of Michigan Environmental Council and Natural Resources Defense
9 Council, collectively “MEC-NRDC.”

10 **Q. Please describe your educational background.**

11 A. I received a Master of Public Policy degree from the University of Indiana (Bloomington) in
12 2007. That is a two-year, multi-disciplinary degree focused on applied economics, statistics
13 and policy development. I also received a Bachelor’s degree in Comparative Sociology from
14 the University of Puget Sound in 2003.

15 **Q. Please summarize your business and professional experience.**

16 A. I have worked in the energy industry for nearly twenty years leading research aimed at
17 improving strategy and performance of energy programs. My work has focused on program
18 evaluation and utility system planning, with particular focus on programs and policies
19 regarding energy efficiency, demand response, and strategic electrification. That included
20 research and analysis regarding the planning, design, and evaluation of dynamic rate
21 programs. Much of my work includes economic analysis, including benefit-cost analyses of

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1 various distributed energy resources and electrification measures. A copy of my curriculum
2 vitae is attached as MEC-1.

3 **Q. Please describe your current role and relevant work experience.**

4 A. I joined EFG in January of 2025. I have developed, directed, and implemented research
5 aimed at improving the performance of energy programs on a range of topics, including
6 extensive work regarding income-eligible programs, demand response, and flexible load
7 resources. Examples of recent work relevant to this case include:

- 8 • Since 2022, representing Citizens Action Coalition in providing technical review,
9 expert testimony, and recommendations on demand response and dynamic pricing
10 program design, tariff design, and planning studies across five investor-owned utilities
11 in Indiana.
- 12 • Evaluations of Portland General Electric's (PGE) residential demand response pilots
13 between 2016 and 2021, including time of use rates, peak time rebates, behavioral
14 demand response, smart thermostat direct load control, and its Smart Grid Test Bed
15 project, the latter focused on customer value proposition, messaging, and engagement
16 regarding various demand response products.
- 17 • Research and analytics supporting utility time-varying rate programs, including:
 - 18 ○ PGE (2020-2021): conducted assessment informing PGE time-of-day rate
19 schedules, including development of rate impact calculator, sensitivity
20 testing for load shifting, and analysis of customer preference.
 - 21 ○ Black Hills Energy (2018-2019): developed research design and sampling
22 plans for a time-varying pricing pilot, additionally provided expert testimony
23 to support Black Hills Energy's filing.

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- 1 • Conducted a 2022 study for the Regional Technical Forum and Northwest Power and
2 Conservation Council regarding impacts of flexibility in power system planning,
3 including framework development for interactions between energy efficiency, demand
4 response, and time-varying rates.
- 5 • Conducted over 70 planning, research, and evaluation studies of income qualified
6 energy programs, including traditional EM&V (Evaluation, Measurement, and
7 Verification), non-energy benefit assessments, and geographic analysis. Specifically in
8 Michigan, I led multiyear evaluations of Consumers Energy's income-qualified energy
9 program portfolio (Helping Neighbors) in 2012 through 2017 and led low-income
10 needs assessment initiatives for Michigan investor-owned utilities prior to leaving
11 Cadmus in 2021.

12 I am also currently participating in a rate design working group led by the Northeast Energy
13 Efficiency Partnership (NEEP) aimed at evaluating different rate design options and creating
14 a decision-making framework linking designs to optimized outcomes (e.g., efficiency,
15 electrification, affordability, peak demand reduction).

16 Prior to joining EFG in January 2025, I was director on Cadeo's distributed energy resources
17 and electrification team. In this role (2021-2024), I led research, evaluation, and analytics for
18 utility energy efficiency, demand response, and electrification programs. I also provided
19 regulatory support for clients in utility clean energy planning filings, including Puget Sound
20 Energy's Clean Energy Implementation Plans, Xcel Colorado's Strategic Initiatives, and
21 several DSM planning studies for Indiana investor-owned utilities.

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1 **Q. Have you previously filed expert witness testimony in other proceedings before the**
2 **Michigan Public Service Commission?**

3 A. I have not. I have, however, provided or supported expert testimony in Colorado, Indiana,
4 Illinois, and Washington.

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

6 A. Yes, I am sponsoring the following exhibits:

7 MEC-1: Scott Reeves Curriculum Vitae

8 MEC-2: Consumers' Response to Discovery Request MNSC-CE-0315

9 MEC-3: Consumers' Response to Discovery Request MNSC-CE-0313

10 **II. TESTIMONY OVERVIEW**

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

12 A. The purpose of my testimony is to provide information for the Michigan Public Service
13 Commission (MPSC or Commission) that supports requiring Consumers Energy
14 (Consumers) to develop and propose an electric heat or heat pump rate design in its next rate
15 case.

16 **Q. Please summarize the rationale for such a proposal.**

17 A. Switching out fossil fuel-fired appliances for electric ones (known as "electrification") in
18 homes and buildings is a key strategy for reducing greenhouse gas emissions to achieve state
19 climate goals, yet current rate structures discourage electrification. The need to reduce
20 emissions related to Michigan's energy use is clearly articulated in state energy policy goals
21 (described in Section II.B below). Rate designs that are more favorable to electrification can
22 be put in place while benefiting not only customers who electrify but other customers as well.

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1 **Q. How do Consumers' current rate structures discourage electrification?**

2 A. Under current residential electric rates, a customer that electrifies their space heating would
3 pay a substantially higher amount than the cost of serving any added electric load. As a result,
4 the customer economics of electrification are much worse than they need to be.

5 Customers who electrify their space heating will have an increased electric bill associated
6 with added heating load. Under Consumers' default residential rate (Summer On-Peak Basic
7 Rate RSP), these costs are recovered through a flat winter season rate structure largely
8 through volumetric pricing (\$/kWh). While electrification could result in a reduced cost
9 associated with home space heating by replacing systems run on fossil fuels like propane and
10 oil, replacement of natural gas systems will likely result in an increased heating bill, which
11 reflects the majority of customers in Michigan (with approximately 77% natural gas heated
12 household).¹ Regardless of whether electrification reflects an increase or decrease in heating
13 costs, customers that electrify will experience an increase their winter season electric bills
14 associated with new electric usage. The net effect discourages electrification by increasing
15 utility bills or does not sufficiently decrease bills to justify the customer's investment in
16 electrification.

17 Increased electric loads spread recovery of fixed costs over more sales, meaning that
18 customers that have electrified their heating generate more revenue through these winter-
19 season volumetric rates, at times when usage is not directly contributing to the summer
20 system peak. Energy rates are typically designed to recover fixed system costs, which occur

¹ MPSC Staff, *Winter Energy Appraisal*, https://www.michigan.gov/mpsc/-/media/Project/Websites/mpsc/regulatory/reports/energy-appraisal/Michigan_Energy_Appraisal_Winter_2022.pdf?rev=514a22213502462ab358902b2feebf3e&hash=AAF0F8E5119E9A145B003F27AF48461E (accessed September 26, 2025).

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1 independent of usage, and on-peak system costs, which primarily occur in summer. These
2 design elements can result in cost-overcollection from customers with electric heating.

3 Existing rates discourage electrification primarily due to the prospect of increased energy
4 costs of electric space heating compared to natural gas. The cost increase associated with
5 added winter heating loads also suggests electrified customers pay a higher portion of fixed
6 system costs compared to non-electrified customers, effectively overpaying. Both problems
7 could be corrected through an alternative rate design.

8 **Q. How would a specialized electric heat rate encourage electrification where Consumers'**
9 **current rate structures do not?**

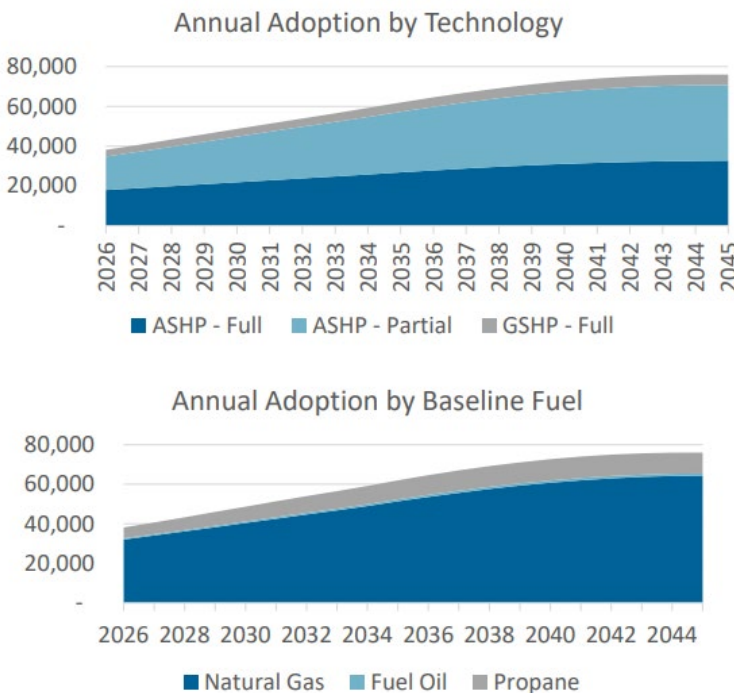
10 A. Specialized rate structures can be designed to address both challenges discussed above by:
11 (1) encouraging heat pump adoption that supports climate goals through building
12 decarbonization, and (2) resolving overpayment issues for heat pump customers caused by
13 standard rates that fail to reflect seasonal cost-of-service variations. Given the urgency of
14 Michigan's climate challenge, substantive market barriers to heat pump adoption, and the
15 likelihood that transforming existing building stock will take decades, an alternative rate
16 design could provide an important jump-start in expediting electrification initiatives.
17 Therefore, Consumers should consider an alternative rate design as soon as possible. I
18 address these points in greater detail in the following sections of my testimony.

19 The state has not adopted a specific climate obligation with emissions reductions targets for
20 buildings that is statutorily binding; however, there is a clear articulation of policy interest
21 for decarbonization in the state. For example, the MI Healthy Climate Plan specifically
22 identifies the objective of building decarbonization and promotion of heat pumps in the near
23 term, displacing oil, propane, and natural gas heating systems. Furthermore, there is likely a

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number of customers that have a personal interest in decarbonizing through electrification of home heating, other gas appliances, and transportation. This is reflected in draft results from a recent electrification potential study identifying approximately 60 million MMBtu savings in heating fuel associated with a forecast of achievable adoption.² Figure 1 provides two tables with adoption forecasts for HVAC electrification by technology and baseline fuel, showing approximately 40,000-50,000 projects by 2030 with the majority occurring in homes with natural gas baselines.

Figure 1. Max HVAC Electrification Adoption by Technology and Fuel (by 2045)



² State of Michigan – Statewide Energy Waste Reduction, Demand Response, and Efficient Electrification Potential Study – *Technical Conference* #3, *September 10, 2025*, <https://www.michigan.gov/mpsc/commission/workgroups/2025-energy-waste-reduction-demand-response-and-efficient-electrification-statewide-potential-study> (accessed September 26, 2025).

³ *Id.* at slide 8.

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1 **Q: Please summarize your recommendations for the Michigan Public Service Commission.**

2 **A:** My recommendations are as follows:

3 1. The Commission should instruct Consumers to develop a proposal for an electric
4 heating or heat pump rate (EH/HP rate).

5 2. The Commission should require Consumers to work with Commission Staff and other
6 stakeholders in the development of this rate.

7 3. The Commission should require Consumers to present its proposed rate to the
8 Commission for approval within 12 months of the order resolving this rate case, either
9 as part of a future rate case or a stand-alone proposal.

10 4. In developing the rate design details with input from Staff and other stakeholders,
11 Consumers should consider the following elements:

12 a. Options for both seasonal and temporal differentiation.

13 b. EH/HP rates for non-residential customers. While this testimony is focused on
14 residential customers, many of these principles are equally applicable to non-
15 residential customers.

16 c. Tradeoffs between rate designs focused on electric heating in general and those
17 focused on technologies such as prompting heat pumps.

18 d. Tradeoffs relating to eligibility requirements and verification (e.g., self-
19 attestation, consumption analysis, submetering).

20 e. Delivery of the new rate, including strategies and tools for customer and
21 contractor education. Such strategies and tools could include rate impact
22 calculators to help customers understand the cost implications of installing heat
23 pumps and/or fuel switching and opt-out design strategies that would

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1 automatically enroll customers that have received efficiency rebates to install
2 heat pumps, both retrospectively and prospectively.

3 **III. RATIONALE FOR RESIDENTIAL ELECTRIC HEATING RATE**

4 **A. Purpose of Proposal**

5 **Q. What is an electric heating rate, heat pump rate, or technology-specific rate?**

6 **A.** These are examples of specialized electric rate designs that, by accounting for differences in
7 cost allocation or recovery within a given customer class, may encourage the use of specific
8 technologies. Electric heating rates are not new. They offer differential electricity pricing,
9 typically for customers that have installed electric heating systems used as a primary heating
10 source. Technology-specific rates provide specialized energy rates for customers with
11 specific technologies associated with higher volume consumption (e.g., electric vehicles,
12 electric appliances). They typically involve differential per-kWh pricing compared to
13 standard rates for other end uses. They may also involve specific eligibility requirements
14 such as qualifying equipment, professional installation, or participation in load control
15 programs. Heat pump rates are an example of technology-specific rates intended to
16 incentivize the adoption of efficient heat pump technologies by providing a rate structure
17 with seasonal (and potentially temporal) differentiation to account for higher electric usage
18 in winter seasons.

19 In this testimony, I will be discussing a proposal for Consumers to develop a new residential
20 rate that is aimed at encouraging building electrification through the adoption of heat pumps,
21 among other end uses. Conceptually, this could be either an electric heating rate that is

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1 agnostic about the form of electric heat or a technology-specific rate only for customers who
2 install and use heat pumps to meet heating loads.⁴ I am not making an explicit
3 recommendation about which of these options will be the best approach for Consumers and
4 its customer base. For ease of discussion, I will hereafter refer to this proposal as an “EH/HP
5 rate” unless I am making reference specifically to either a heat pump rate or an electric
6 heating rate.

7 **Q. Why should Consumers consider developing an EH/HP rate?**

8 A. There are several reasons to develop a new EH/HP rate at this time. First, a significant
9 amount of electrification of building heating systems is necessary to achieve the state’s
10 climate goals. While decarbonization can occur through several pathways (i.e., reducing
11 emissions profiles of electricity generation, electrifying transportation by substitution of
12 cleaner fuels, reduced fossil fuel consumption in buildings), significant electrification of
13 home end-use loads, particularly space heating, will be required. Currently, over 76% of
14 Consumers’ residential customers have natural gas space heating as their primary heating
15 fuel.⁵ An EH/HP rate would help encourage electrification by reducing the operational costs
16 of installing heat pump technologies to electrify home space heating, thereby addressing a
17 central barrier to adoption. The current electric rate structures discourage heat pump adoption
18 because most customers replacing natural gas systems would experience increased energy
19 bills; this is often the case because the cost per unit of heating is higher under electric rates
20 relative to gas. Despite availability of equipment incentives that reduce upfront costs for

⁴ It is possible that this rate could also be designed with price signals encouraging electrification for both buildings and transportation through seasonal and temporal differentiation. This may be an ideal outcome where a single rate could encourage electrification for both applications.

⁵ Consumers Energy. Residential Appliance Saturation and Home Characteristics Study. October 2018.

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1 purchasing heat pumps, the increase in ongoing operational costs for home heating can be a
2 significant barrier to adoption.

3 **Q. What other reasons support development of an EH/HP rate at this time?**

4 A. Under current residential rate structures, Consumers will collect significantly more revenue
5 than necessary to serve the added load from heat pumps. Standard energy rates are typically
6 structured to charge customers the same amount (or relatively similar amounts) for energy
7 on a per-unit basis in each month, despite higher electric system costs occurring during
8 season-specific peak periods and a significant portion of fixed system costs being
9 independent of usage. This allows utilities to spread the recovery of system costs throughout
10 the year largely through variable charges based on volume of energy savings.⁶ Since
11 Consumers is summer peaking, a significant portion of system costs are associated with
12 meeting summer peak load;⁷ the remaining are independent of or not marginal to usage.

13 Typically, customers that install heat pumps to replace fossil fuel systems and existing air
14 conditioning will increase energy consumption in winter through added electric space
15 heating, while potentially decreasing energy consumption in summer through increased
16 cooling efficiency. Under standard rates, heat pump customers will face higher energy bills
17 in winter, through which the utility recovers more than what is needed to cover the costs of
18 serving the added winter electricity demand. Therefore, these customers pay a higher portion

⁶ The majority of Consumers' residential customers are on its default Summer On-Peak Rate (RSP), which has a time-varying component (daily on-peak vs. off-peak charges) during the four summer months from June through September and a flat rate for the eight non-summer months from October through May.

⁷ According to the Energy Information Administration's Annual Electric Power Industry Report (Form EIA-861), as of 2023, Consumers Energy is a summer-peaking utility with peak demand of 7,518 MW in summer and 4,928 MW in winter. U.S. Energy Information Administration, *Annual Electric Power Industry Report, Form EIA-861 detailed data files*, <https://www.eia.gov/electricity/data/eia861/> (accessed September 26, 2025).

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1 of the overall cost of service through these increased bills. While this is an issue for almost
2 all residential end use consumption, it is specifically problematic for heat pumps due to
3 policy objectives aimed at inducing more heat pump adoption. This has been described as an
4 “inverse cost shift” effect where, under standard electric rates with volumetric pricing aimed
5 at recovering portions of both fixed infrastructure costs and variable costs, heat pump
6 customers end up paying a higher portion of system fixed costs.⁸

7 **Q. Does Consumers currently offer an electric heating or heat pump rate?**

8 A. No. Consumers currently offers several residential electric rates, three with slight temporal
9 and seasonal differentiation that provide on-peak and off-peak energy charges that vary by
10 summer (June through September) and non-summer (October through May) seasons. These
11 include Summer On-Peak Basic Rate (RSP), Smart Hours Rate (RSH), and Nighttime Savers
12 Rate (RPM). The RSH and RPM rates each include a slight seasonal differentiation where
13 summer season on-peak and off-peak energy charges are slightly higher than during the non-
14 summer season (approximately \$0.06 higher on-peak and \$0.02 higher off-peak in summer
15 compared to non-summer periods). As of 2023, over 97% of Consumers’ residential sector
16 electric customers, energy sales, and revenue are attributed to the Rate RSP.⁹ However, these
17 rates do not create the kind of advantageous price signal that an EH/HP rate would create,
18 nor do they address the imbalance between system costs and rates that heating customers
19 experience (discussed further in Section III.C).

⁸ NYSERDA 2019. *New Efficiency: New York – Analysis of Residential Heat Pump Potential and Economics*, <https://www.nyserdera.ny.gov/-/media/Project/Nyserda/Files/Publications/PPSER/NYSERDA/18-44-HeatPump.pdf> (accessed September 26, 2025).

⁹ Consumers’ response to discovery request MNSC6-CE-0310, Attachment U21870-MNSC-CE-0310_2023 MPSC P-521.

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1 **Q. Are you aware of other Michigan utilities with EH/HP rates?**

2 Upper Peninsula Power Company (UPPCO) currently has electric heating rates for
3 residential (AH-1) and commercial (H-1) customers. To be eligible, a customer must use
4 electric space heating equipment for their primary heating source, and the equipment must
5 be permanently installed. UPPCO's electric heating rates are structured as declining block
6 rates with seasonal differentiation that provide rate reduction for distribution and power
7 supply charges beyond the first 500 kWh between October through May. For example, the
8 AH-1 rate for distribution service is set at \$0.13567 per kWh for the first 500 kWh and then
9 is reduced to \$0.06783 per kWh for usage beyond 500 kWh between October through May.¹⁰

10 **Q. Has Consumers offered similar rates in the past?**

11 A. Yes. From 1963 to 2008, Consumers offered a residential space heating rate (Residential
12 Electric Heating Rate A-1). Similar to the UPPCO rate, it was available to customers with
13 permanently installed electric heating used as the primary heating source. It was designed as
14 a two-tiered declining block rate providing customers with a reduced price per kWh beyond
15 the first 20 kWh per day during the months of October through May. The Commission
16 approved its termination in 2008 as one of the Company's "non-controversial" proposed
17 tariff changes.¹¹ Consumers witness Miller testified that the historical rationale for this
18 electric heating rate was to compete for residential heating loads and that a "rate design that

¹⁰ Upper Peninsula Power Company, *Residential Heating Service*, <https://www.uppco.com/wp-content/uploads/2025/01/D.-AH-1--Residential-Heating-Service--Dec-20-2024.pdf> (accessed September 26, 2025).

¹¹ Case No. U-15245, Order, June 10, 2008, p 68.

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1 better reflects temporal cost spreads (seasonality) would be far simpler and more
2 equitable.”¹²

3 **Q. Does Consumers’ current rate schedule include a sufficient proxy or substitute for an**
4 **EH/HP rate?**

5 A. No, it does not. As noted, several residential rates do include a slight seasonal differentiation;
6 however, they are not designed for the purposes highlighted above of (1) encouraging
7 adoption of heat pump technologies as a driver to meet climate policy goals, or (2) addressing
8 the overpayment issues regarding increased revenue derived through electric heating bills
9 from customers that install heat pumps. The current rates do not appear to provide sufficient
10 seasonal differentiation to materially change the economics of improving operational costs
11 of heat pump adoption. Consistent with Company witness Miller’s testimony in Case No. U-
12 15245, there are more current examples of innovative rate designs aimed at encouraging heat
13 pump adoption that better address seasonality, simplicity, and equity with the intention of
14 addressing the purposes outlined in this testimony. I address examples of these rate designs
15 in the following sections (III.C and III.E) of my testimony.

16 **Q. Under Consumers’ current default residential rate, will energy bills associated with**
17 **heating increase for customers who install heat pumps?**

18 A. The answer depends on several factors, including the efficiency of the building envelope
19 (affecting how much heat is needed); characteristics of the existing space heating system
20 being replaced, including fuel type and equipment efficiency; characteristics of the heat

¹² Ex MEC-2, Consumers’ Response to Discovery Request MNSC-CE-0315; Direct Testimony of Hubert W. Miller, III, 10 Tr 1436.

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1 pump being installed; and how the customer uses the heat pump. Customers with existing
2 heating systems that rely on propane or oil will likely see a bill decrease from replacing their
3 spacing heating with an efficient electric system. In contrast, customers that replace natural
4 gas systems with new heat pumps will likely experience an increase in energy bills.¹³

5 Below, Table 1 provides a comparison of the variable costs of heating for different
6 equipment and fuel types. I have used current Consumers fuel prices for the variable cost of
7 energy (approximately \$0.16/kWh and \$0.79/therm)¹⁴ and average weekly retail Michigan
8 propane price for the past winter (November 2024 through March 2025) from the U.S.
9 Energy Information Administration (EIA).¹⁵ I have also assumed average heating
10 efficiencies for each system based on a 2021 Michigan Baseline Housing Study, with fossil
11 fuel systems at 86% annual fuel utilization efficiency (AFUE) and a high efficiency heat
12 pump based on an average seasonal coefficient of performance of 2.3.¹⁶ Based on these
13 assumptions, replacement of a propane system with a heat pump would reduce annual
14 heating bills by nearly 30% and save the customer nearly \$500 per year. Alternatively,
15 replacement of gas systems would cause an increase in annual heating bills. Assuming

¹³ Heat pump installations may also reduce energy bills associated with cooling usage reflecting higher efficiency equipment compared to existing systems.

¹⁴ Electricity pricing based on winter season variable pricing per kWh from Rate RSP; natural gas pricing based on distribution and recovery charges per MCF from Residential Service Rate A. Consumers Energy Company, *Rate Book for Natural Gas Service*, <https://www.consumersenergy.com/-/media/CE/Documents/rates/gas-rate-book.ashx> (accessed September 26, 2025).

¹⁵ U.S. Energy Information Administration, *Weekly Heating Oil and Propane Prices*, https://www.eia.gov/dnav/pet/PET_PRI_WFR_DCUS_SMI_W.htm (accessed September 26, 2025).

¹⁶ Cadmus, *Michigan Baseline Housing Study*, May 2021, <https://www.michigan.gov/mpsc/-/media/Project/Websites/mpsc/regulatory/ewr/MEMD-and-BRM/Michigan-Baseline-Housing-Study-Final-2021-05-25.pdf> (accessed September 26, 2025). The efficiencies used here are illustrative and, particularly for the heat pump may be conservative compared to average COPs of cold climate heat pumps which can typically range from 2.0 to 4.0 depending on temperature.

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average household gas consumption of approximately 650 therms/year, energy costs associated with gas consumption are approximately \$500 for a typical residential home.^{17 18}

In assuming an MMBtu equivalent home heating of approximately 7,000 kWh per year, annual energy costs associated with electric space heating exceed \$1000, approximately twice that of annual gas heating costs.

Table 1. Comparison of Heating Costs by Fuel Type

Fuel	Current Fuel Rate (\$/unit) ¹⁹	Units	BTU per unit	Fuel Price (\$/MMBtu of Consumption)	Avg Equip. Efficiency ²⁰	Operating Cost (\$/MMBtu of Heat Output)	Annual Heating Load ²¹	Annual Variable Heating Cost
Propane	\$2.28	gallon	91,452	\$24.96	86%	\$29.02	55.95	\$1,624
Natural Gas	\$0.82	therms	100,000	\$8.24	86%	\$9.58	55.95	\$536
Electricity	\$0.16	kWh	3,412	\$47.91	240%	\$19.96	55.95	\$1,117

Additionally, recent studies by the American Council for an Energy-Efficient Economy (ACEEE) and the Energy Systems Integration Group (ESIG) evaluating alternative rate designs to support building electrification each modeled changes in energy consumption and associated replacements in gas furnaces with air-source heat pumps, both finding that the net

¹⁷ EIA 2020 Residential Energy Consumption Survey (RECS), Table CE5.4. which estimated average natural gas consumption for space heating to be 65.06 MMBtus for the East North Central region <https://www.eia.gov/consumption/residential/data/2020/c&c/pdf/ce5.4.pdf>

¹⁸ This is generally consistent with MNSC witness Chris Neme's testimony in Case No. U-21224, which found propane furnaces replaced by cold climate heat pumps would reduce annual heating bills over 40% and save approximately \$700 per year. Case No. U-21224, Direct Testimony of Chris Neme, 4 Tr 3624-28.

¹⁹ Propane price is based on EIA source for Michigan average weekly pricing from November 2024 to March 2025 (https://www.eia.gov/dnav/pet/PET_PRI_WFR_DCUS_SMI_W.htm); Gas and electric rates are based on current Consumers rates (Gas Residential Service Rate A, [consumersenergy.com/-/media/CE/Documents/rates/gas-rate-book.ashx](https://www.consumersenergy.com/-/media/CE/Documents/rates/gas-rate-book.ashx); and Summer On-Peak Basic Rate, [electric-rate-book.pdf](https://www.consumersenergy.com/-/media/CE/Documents/rates/electric-rate-book.pdf))

²⁰ Cadmus, *Michigan Baseline Housing Study*, supra n 16.

²¹ EIA Table CE5.4 Detailed household natural gas and propane end-use consumption—averages, 2020, <https://www.eia.gov/consumption/residential/data/2020/c&c/pdf/ce5.4.pdf> (accessed September 26, 2025).

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increase in electric space heating increased average energy bills compared to gas heating bills. The ESIG study found that average space heating bills increased by over \$200 based on a standard flat electric rate, while alternative rate options that consider temporal and seasonal differentiation, demand charges, or increased fixed costs all yield reductions in energy bills between \$450 to \$1200 annually.²² The ACEEE study similarly modeled electrification scenarios for prototypical homes in four cold-climate states (Colorado, Connecticut, Maine, and Minnesota) and found that heat pump installation always reduced energy bills for oil and propane users using standard electric rates, while energy bills increased for replacement of natural gas systems by nearly \$500 on average annually (ranging from \$170 to \$800 across the four states). The ACEEE study also found that shifting to time-of-use (TOU) rates had a minimal impact (with less than \$70 in additional savings).²³

B. Policy Context

Q. What existing policies in Michigan encourage decarbonization?

A. There are several Michigan-specific policies that are currently guiding decarbonization initiatives and goals aimed at reducing greenhouse gas emissions from the energy sector. These include the following:

- ***MI Healthy Climate Plan*** – In 2022, pursuant to Michigan Executive Directive 2010-10, the Michigan Department of Environment, Great Lakes, and Energy (EGLE) developed a state action plan to reduce greenhouse gas emissions and promote initiatives that drive state

²² Sergici, et al., *Heat Pump–Friendly Cost-Based Rate Designs*, ESIG, January 2023, <https://www.esig.energy/wp-content/uploads/2023/10/Heat-Pump%E2%80%93Friendly-Cost-Based-Rate-Designs.pdf> (accessed September 26, 2025).

²³ Malinowski, et al., *Electricity Rates That Keep Bills Down after Electrification of Home Heating*. ACEEE, April 2025, <https://www.aceee.org/sites/default/files/pdfs/b2502.pdf> (accessed September 26, 2025).

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1 climate policy goals. The plan defines six categories of climate action required to meet
2 goals. Regarding building decarbonization, the plan establishes a goal to reduce emissions
3 related to heating homes and businesses by 17% by 2030. The plan also outlines broader
4 goals to reduce greenhouse gas emissions (relative to 2025 levels) by 28% by 2025 and
5 52% by 2030, and to achieve carbon neutrality by 2050.²⁴

6 The plan is explicit about the role buildings play in contributing to decarbonization goals.
7 It indicates that 18% of state greenhouse gas emissions occur through the built
8 environment, primarily due to heating fuels like natural gas, propane, and oil. A reduction
9 of approximately 3% of emissions from buildings will be required each year between 2022
10 and 2030 to reach its goal of 17% reduction in building related emissions by 2030.²⁵

- 11 • **2023 Energy Legislation** – In November 2023, five public acts were passed and signed
12 into law that aimed to encourage clean energy solutions that avoid or reduce greenhouse
13 gas emissions and set environmental policy goals related to the energy sector. In general,
14 the purpose of the 2023 legislation is “to promote the development and use of clean and
15 renewable energy resources and the reduction of energy waste” through cost effective
16 initiatives that provide diversity of clean energy resources and greater energy security,
17 encourage private investment, provide improved air quality and other benefits, and increase
18 reliable and resilient energy supply.²⁶

²⁴ EGLE, *MI Healthy Climate Plan*, April 2022, <https://www.michigan.gov/egle/about/organization/climate-and-energy/mi-healthy-climate-plan> (accessed September 26, 2025).

²⁵ *Id.* at 41-43.

²⁶ MCL 460.1001.

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1 Public Act 235 establishes a clean energy standard that sets a goal of 80% by 2035 and
2 100% by 2040.²⁷ This requires electric providers to achieve a clean energy portfolio
3 defined as a percentage of total retail electric sales generated through non-emitting clean
4 or renewable energy sources.²⁸

5 Public Act 229 defines “efficient electrification” measures as part of a utility’s energy
6 waste reduction (EWR) plans, which reduce energy consumption and greenhouse gas
7 emissions due to energy use. It also allows electricity providers to recover the costs
8 associated with an efficient electrification program.²⁹

9 **Q. Does Consumers currently have any planning initiatives or programs aimed at building**
10 **electrification?**

11 A. Not that I’m aware of. Consumers does have a variety of initiatives supporting heat pump
12 adoption under its EWR portfolio to improve electric efficiency, though not specifically
13 aimed at advancing building electrification.³⁰ Consumers has elected not to submit an
14 optional efficient electrification (EFEL) plan as part of its EWR submission under the Energy
15 Optimization Plan (U-21680), which would include explicit strategies and goals more
16 directly associated with building electrification and fuel switching.³¹

17 Additionally, in Case No. U-21224, Consumers agreed to develop a home heating
18 electrification pilot aimed at replacing systems that relied on delivered fuels. However, the

²⁷ MCL 460.1051(1).

²⁸ *Id.*; MCL 460.1003(g).

²⁹ MCL 460.1072; MCL 460.1005(a).

³⁰ Ex MEC-3, Consumers’ Response to Discovery Request MNSC-CE-0313.

³¹ See Case No. U-21680.

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Commission rejected Consumers' proposed pilot in Case No. U-21389, citing a lack of benefit cost analysis among other concerns.³² While the Commission encouraged Consumers to resubmit this proposal and address concerns, no subsequent proposal has been provided at this time.

In summary, Consumers has some limited initiatives that indirectly support electrification of building end uses, but these are focused on energy efficiency and not directly aimed at electrifying end uses, such as by replacing gas heating equipment with heat pumps at scale. As such, Consumers is not proactively working to decarbonize the building sector through electrification of fossil fuel end uses, which is a specific pathway to meeting state climate goals.

Q. What are the pathways to achieve Michigan climate and clean energy goals?

A. As noted above, there are three primary sectors where Michigan can reduce greenhouse gas emissions and achieve its policy objectives: power generation, transportation, and buildings. These are discussed in the MI Healthy Climate Plan's roadmap to achieve its 2030 greenhouse gas emission reduction goals and commonly included in climate plans and decarbonization strategies.

Q. How important will addressing decarbonization through buildings be in achieving Michigan's climate goals?

A. Climate research indicates that reducing greenhouse gas emissions through building end uses, such as space and water heating, is critical to meeting climate goals. While the

³² Case No. U-21389, Order, March 1, 2024, p 302.

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1 magnitude of savings that could or should come from the building sector is debatable, some
2 amount of decarbonization through electrification of building end-use loads will be
3 necessary. Specifically for Michigan, the MI Healthy Climate Plan indicates that 17% of
4 emissions reduction should occur through buildings to meet its 2030 goals. Additionally,
5 draft results from a recent Michigan electrification study shows significant potential for heat
6 pump electrification (as noted above and shown in Figure 1).³³

7 Despite these state-specific goals and general consensus on the need for some role for
8 building electrification, significant barriers to customer adoption of heat pump technologies
9 remain. While several existing Consumers' initiatives address specific barriers (including
10 increased customer and contractor education and incentives to reduce upfront equipment
11 costs), my understanding is that no current retrofit programs proactively target building
12 electrification. This suggests that, while decarbonization of the building sector is a key lever
13 for achieving state climate goals, most current initiatives are passive contributors rather than
14 active campaigns explicitly aimed at electrifying end-use equipment in homes and
15 businesses.

16 Furthermore, operational cost economics remain a major barrier for customers given the
17 potential to increase energy bills due to higher home heating under electric rates.³⁴ Recently,

³³ *State of Michigan – Statewide Energy Waste Reduction, Demand Response, and Efficient Electrification Potential Study* – Technical Conference #3, September 10, 2025, <https://www.michigan.gov/mpsc/commission/workgroups/2025-energy-waste-reduction-demand-response-and-efficient-electrification-statewide-potential-study> (accessed September 26, 2025).

³⁴ Note, this is not always the case, as increases in efficiency and fuel price differentials can prove to be cost effective on a case-by-case basis. For example, in Case U-21224, MNSC witness Chris Neme provided an analysis showing cost savings of approximately 50% through electrification of space and water heating relative to a baseline of propane consumption.

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1 other states and utility jurisdictions have considered proposals for electric heat or heat pump
2 rates as a mechanism to address similar concerns outlined in this testimony.

3 **C. Rate Structure and Delivery Considerations**

4 **Q. Please provide a brief overview regarding the purpose of rate design.**

5 A. The purpose of rate design is for utilities and regulators to determine a framework for energy
6 pricing that allows for recovery of a utility's cost of service in running the electricity system
7 while attaining policy compliant outcomes. There are numerous complexities associated with
8 doing this, along with numerous economic principles that serve as guidance for ratemaking
9 standards and practices. Once a utility has estimated its revenue requirement for providing
10 services, recovering costs, and earning a reasonable rate of return, a rate design will establish
11 mechanisms to collect costs from ratepayers to account for the recovery of the utility's cost
12 of service. Although total revenue recovery is fixed, rate design impacts who pays and how
13 much they pay, and it also provides incentives for customers to act upon.

14 Prior to designing specific rates for revenue collection, several preliminary steps are
15 required. First, customer classes are established based on common sets of characteristics
16 (e.g., voltage, patterns of use, size or profile of end use loads) to define categories of
17 customers under given rate schedules and provide uniform pricing for energy services.
18 Second, a framework for cost allocation is determined (typically through cost-of-service
19 studies) to assign attribution of utility costs to different types of customers. This should
20 account for cost causation, attributing costs to be paid for by those customers that caused
21 them to occur. Utility costs are separated by function (e.g., production, distribution) and used
22 to develop rate schedules and tariffs that allow recovery of these costs through different

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1 billing components, such as volumetric charges (e.g., energy charges per kWh) and fixed
2 charges (e.g., monthly customer charges).

3 **Q. What are commonly cited principles of rate design?**

4 A. Most rate design relies on set of economic principles largely attributed to James Bonbright's
5 1961 and 1988 works, "Principles of Public Utility Rates."³⁵ These principles are often used
6 as criteria to evaluate whether rate proposals are "just and reasonable" and prevent "undue
7 discrimination." I have summarized several of these core principles below:³⁶

- 8 • ***Sufficiency*** – design rates to yield revenues to cover energy system costs (revenue
9 requirement) plus a reasonable rate of return.
- 10 • ***Fairness*** – design rates to fairly apportion costs between both (1) customers and utilities,
11 and (2) across customer classes, to avoid undue discrimination (e.g., cross-subsidization).
- 12 • ***Efficiency*** – design rates to accurately reflect cost of service components (e.g., production,
13 delivery) and provide efficient price signals to encourage behavior adoption.
- 14 • ***Customer Acceptance*** – design rates that are easy to understand, interpret, and provide
15 ability for a customer to respond.
- 16 • ***Bill Stability*** – design rates that remain stable over time, ensuring greater consistency in
17 cost recovery to reduce risks in addressing highly variable fluctuations in actual costs of
18 associated with electricity service.

³⁵ Regulatory Assistance Project, *Principles of Public Utility Rates*, <https://www.raponline.org/knowledge-center/principles-of-public-utility-rates/> (accessed September 26, 2025).

³⁶ NARUC. 2021. *Rate Design for Cost-Effective Tariffs*. <https://pubs.naruc.org/pub.cfm?id=7BFEF211-155D-0A36-31AA-F629ECB940DC> (accessed September 26, 2026).

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While not an economic principle, rate design is commonly described as an art and a science, with “art” referring at least in part to the creativity one can use to address the complexities described (e.g., cost allocation, defining customer classes, avoiding cross-subsidization). The art of rate design can also reflect the influence of public policy and how to develop and design rates in accordance with these goals. This art involves, in part, providing the right policy signals and, at a minimum, not working at cross purposes with intended policy goals.

Q. What are some inherent challenges with rate making that complicate the ability to achieve these objectives?

A. Economic theory provides clear guidance that the retail price of electricity (collected through energy rates) should be set at the marginal cost of providing that electricity.^{37 38 39} In practice, this is difficult given variability in the marginal price of electricity by different times and locations. Rate designs like TOU rates make progress toward setting pricing consistent with marginal costs, better achieving the principle of efficiency noted above, but does not reflect true variation.

Additionally, revenue recovery requires collection of both variable costs of energy (e.g., production, distribution) as well as fixed costs (e.g., grid infrastructure, utility administration

³⁷ See, for example, A. E. Kahn, *The Economics of Regulation* (Cambridge, MA: MIT Press, 1988), Vol. I, 75. “The economic ideal would be to set all public utility rates at short run marginal costs (with appropriate adjustments for the problems of second-best); and these must cover all sacrifices, present or future and external as well as internal to the company, for which production at the margin is causally responsible.”

³⁸ See, for example, W. Kip Viscusi, John M. Vernon, and Joseph E. Harrington Jr., *Economics of Regulation and Antitrust*, fourth ed. (Cambridge, MA: MIT Press, 2005), 344–45. “The most obvious candidate for the efficient price is, of course, marginal cost.” The authors specifically refer to marginal cost as the cost of producing the next unit of good. For the electric sector, this is short-run system marginal cost when externalities are included.

³⁹ Severin Borenstein. *The Economics of Fixed Cost Recovery by Utilities*, *Electricity Journal* 29, no. 7 (September 2016). 4-5. <https://www.sciencedirect.com/science/article/abs/pii/S1040619016301130> (accessed September 26, 2025).

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costs). Even if volumetric pricing is set at the marginal cost of energy, this may not generate sufficient revenue to cover a utility's total expenses.⁴⁰ Fixed costs reflect investments in the electricity system that do not directly align with the volume of energy savings. These include transmission and distribution infrastructure, meters, billing, and other costs, and can be further divided between customer-specific fixed costs (e.g., metering, billing expenses, new customer interconnection) and system-wide fixed costs (e.g., construction and maintenance of distribution infrastructure, wildfire prevention).

Q. What are implications of these challenges as they relate to developing rate designs and reflection of costs in customer energy bills?

A. These challenges affect the determination of how best to allocate fixed costs to specific customers or customer groups, and how to develop rates that generate the required revenue while minimizing economic efficiency losses, encouraging policy-compliant behavior, and achieving equitable outcomes. Various options exist for allocating revenue requirements and cost attribution across customers and designing rates to recover these fixed costs.⁴¹

Consumers' current residential rates illustrate these challenges, as they are somewhat cost reflective given slight variation by time of day and season but do not precisely account for the variability of marginal energy costs nor perfectly allocate the fixed system costs reflecting each individual customer within the residential customer class. For these reasons, some level of cross-subsidization will naturally occur, which is generally accepted and practical as a function of defining a limited set of rate options by customer classes. Too much

⁴⁰ See *Id.* at p 6 onwards.

⁴¹ See *Id.* at pp 7-17 for a review of different options along with critical analysis of the potential benefits and drawbacks.

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1 cross-subsidization can become overly burdensome on specific customer segments and,
2 consistent with the fairness and efficiency principles, ideally should be addressed through
3 rate design.

4 **Q. How do these challenges associated with rate design change over time as more customers**
5 **electrify?**

6 A. Given Michigan's climate goals and the role building electrification will need to play, we
7 can anticipate an increase over time in the number of residential customer homes in
8 Consumers' territory that will adopt heat pumps to electrify space and water heating end
9 uses. As this occurs, a larger subsegment of residential customers through added electric
10 space heating will generate more revenue for the utility through increased energy bills during
11 the heating season. Revenue from higher energy bills associated with increased electric
12 heating loads will include both variable and fixed components of a utility's cost of service
13 within its volumetric pricing structure (i.e., cost per kWh). Over time, this will reflect a
14 subsegment of heat pump customers paying a larger portion of fixed costs, effectively
15 subsidizing energy costs for non-participants within the residential customer class. This
16 violates the cost causation principle that costs should be fairly attributed and paid for by the
17 customers that cause them to occur. The increased revenue through winter season charges
18 would effectively over-collect fixed infrastructure costs largely required to accommodate
19 Consumer's system peak in the summer season. While this is true for most added winter
20 consumption, it is uniquely problematic for heat pumps in that it fails to account for the value
21 in heat pump adoption and in how building electrification reflects state policy priorities.

22 To address this cross-subsidy, create a rate structure that brings seasonal energy costs more
23 closely in line with marginal pricing, and enable acceleration of heat pump adoption in

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1 service to Michigan state climate goals, Consumers should collaborate with stakeholders in
2 and develop a proposal for an EH/HP rate.

3 **Q. Within the residential customer class, how does a customer that electrifies their fossil**
4 **fuel end uses impact system costs?**

5 A. When a customer adds new electric loads, this puts downward pressure on all other
6 ratepayers within a given customer class. This increased consumption translates into
7 increased revenue used to cover the cost of service attributed to that customer class. This
8 revenue covers both variable costs (like fuel) and fixed costs (power supply and delivery
9 infrastructure). Since the utility system is designed around peak demand planning, customers
10 who electrify and increase winter energy usage pay more than the marginal cost of energy –
11 they also contribute more revenue toward fixed infrastructure costs needed for summer peak
12 periods.

13 As electrification grows, utilities will collect more revenue through increased winter sales.
14 This surplus revenue is not treated as profit but redistributed to the entire customer class
15 through credits or bill reductions.

16 However, this creates a structural problem. At scale, electrified customers contribute
17 disproportionately more revenue than their actual cost to serve, effectively subsidizing non-
18 electrified customers within the same rate class. This cross-subsidization violates core
19 ratemaking principles of fairness and non-discrimination, as it creates undue cost shifting
20 between customer groups.

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1 **Q. What are the components of Consumer's Residential Summer On-Peak Basic Rate**
2 **(RSP)?**

3 A. According to the current rate book for electric service, Consumer's Rate RSP includes
4 several components within its monthly energy rate.⁴² There are two components that are set
5 as fixed dollar per customer charges. These include a system access charge (\$8.00 per
6 customer per month) and a Low-Income Energy Assistance Fund Charge (\$1.25 per billing
7 meter per month). All other billing components are structured as volumetric charges set as
8 costs per kWh per month. These volumetric components include charges for energy,
9 capacity, distribution, and some smaller miscellaneous charges (e.g., power plant
10 securitization) and approximate \$0.16 per kWh in winter.

11 **Q. What are the implications of this rate structure considering a future increase in**
12 **electrification through heat pump installation?**

13 A. As a result of electrification, heat pump customers will increase utility revenues through the
14 volumetric pricing associated with added electric space heating. This increased revenue
15 should put downward pressure on rates, given that the added load is not increasing the system
16 peak load in summer and associated costs of service, thereby paying more for fixed system
17 costs during seasonal off-peak periods. If rates are structured to be revenue neutral, adding
18 recovered revenue during off-peak seasons should reduce the annual energy costs for all
19 ratepayers. Under a scenario where building electrification will occur at scale (which is
20 specifically consistent with Michigan climate policy goals), the magnitude of this
21 discrepancy would increase to a meaningful level. Currently energy rates present a paradox

⁴² Consumers Energy Company, *Rate Book for Electric Service*, consumersenergy.com/~media/ce/documents/rates/electric-rate-book.pdf (accessed September 26, 2025).

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1 – they disincentivize increased electrification due to increased energy bills, counter to state
2 climate goals; and, to the extent this customer segment increases, so does the prospect of
3 overpayment for their portion of the cost of service, thereby subsidizing electric rates of
4 customers that do not electrify. Lastly, increased electric heating bills over-collect the cost
5 to serve winter season load, given that the bulk of system costs are designed around the
6 summer system peak.

7 **Q. How would an EP/HP rate achieve or improve upon these principles of rate design?**

8 A. A well-designed EP/HP rate would address and ideally improve upon several of these
9 principles. First, by designing a seasonal rate more closely aligned with the marginal cost of
10 energy and correcting for any potential overpayment of fixed costs, Consumers would enable
11 heat pump customers to pay for electric service that more closely reflects their costs to the
12 system. This would improve the efficiency of their rate relative to the costs they incur, as
13 well as increase fairness by avoiding undue discrimination. This would also increase the
14 accuracy of cost recovery by differentiating electric heating customers as a subsegment with
15 an appropriate energy rate. This rate could be designed simply and, paired with customer
16 education or targeting strategies, improve upon customer acceptance.

17 **Q. What are some key elements related to design and delivery that should be considered**
18 **in developing an EH/HP rate?**

19 A. Here are several elements that should be considered in developing an EH/HP rate:

- 20 • **Eligibility** – consider whether this rate should be designed to be technology-specific, such
21 as requiring the installation of a heat pump for space and/or water heating, or more broadly
22 for customers with electric heating systems; consider eligibility of dual fuel systems (e.g.,

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air source heat pump with natural gas back up) and any related requirements (e.g., specific cross-over temperature settings).

- **Verification** – consider whether this is based on self-attestation, equipment-specific submetering, or involve monitoring or site verification for a sample of participants.
- **Temporal/Seasonal Definitions** – consider seasonal definitions to align with months associated with heating season (e.g., October through May, November through April)); consider if rate should include a time-varying component for daily on-peak vs. off-peak pricing.
- **Participation Requirements** – consider participation period requirements to discourage gaming (e.g., requirement for 12 months of enrollment).
- **Enrollment Design** – consider default of opt-in design vs. opt-out designs that could automatically enroll customers that had received efficiency rebates for installing heat pumps.
- **Pricing Design** – consider options for adjustment of billing elements, such as through fixed vs. variable components of customer charges; consider bill impacts more broadly and if designed to be revenue neutral or positive.

D. Implications for the Grid and Nonparticipants

Q. What impact would a residential EH/HP rate have on customers that do not adopt heat pumps?

A. This will depend on the rate design. An EH/HP rate could be designed to be revenue neutral, address the overpayment issue, and structured to reduce energy bills for heat pump customers

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1 by setting rates at a level designed to recover revenue directly associated with additional
2 costs imposed on the grid. An EH/HP rate could be set more closely to the marginal cost
3 imposed on the grid during the winter season, reflecting a per kWh reduction from the
4 average standard rate. For example, if the marginal cost during the winter season is
5 \$0.05/kWh and the average rate is \$0.17/kWh, the overpayment for heat pump customers
6 would be the difference of \$0.12/kWh. The rate could also be designed to address the issue
7 with customers that electrify while also avoiding any change to rates for the remaining
8 customer population.

9 **Q. Are there other ways that an EH/HP rate could be designed?**

10 **A.** Alternatively, an EH/HP rate could be designed so that there are shared benefits where all
11 customers are better off as a function of cost reallocation (though still revenue neutral for the
12 utility, meaning rates recover costs up to the cost of service allocated to the residential class).
13 Using this same example, Consumers could provide a partial discount to heat pump
14 customers for the winter season, such as reducing rates by 50% of the difference between
15 marginal cost of energy and the standard rate (e.g., \$0.06/kWh), which would give EH/HP
16 customers a reduced winter season energy rate, insulate nonparticipating customers from an
17 unanticipated cost, and spread the benefit associated with any overcollection from heat pump
18 customers to all ratepayers. This creates a win-win situation whereby rates encourage more
19 heat pump adoption, reduce pollution and carbon emissions, reduce participant bills, and also
20 reduce non-participant bills.

21 **Q. What potential impacts could an EH/HP rate have on the power system more broadly?**

22 **A.** As more customers adopt an EH/HP rate over time, there may be need to revisit and revise
23 this rate to better reflect either changing marginal costs or cost allocation across the

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residential class. There is also the possibility that with an increasing number of customers adding electric heating, the increase in energy and demand will introduce new season-specific costs that will need to be recovered. This could involve new location-specific distribution infrastructure costs due to increases in load growth or, eventually, costs associated with a winter system-level peak. Regarding the latter, I presume this is a long way off. Consumers' current peak is over 1.5 times higher in summer (7,518 MW) than winter (4,928 MW).⁴³ If we assumed the incremental diversified winter peak demand of electrifying space heating load is approximately 6 kW,⁴⁴ it will require over 430,000 homes to be electrified to close this gap.⁴⁵ Ideally, a new EH/HP rate would include both temporal as well as seasonal differentiation, providing price signals to encourage demand flexibility and minimize the risk of exacerbating peak effects.

E. Examples of Current Heat Pump Rates

Q. Are there any states or utility jurisdictions that have adopted or are considering EH/HP rates?

A. Yes, there are several examples of recently approved EH/HP rates with the same objectives as those I have outlined in this proposal.

⁴³ 2023 EIA-861.U.S. Energy Information Administration, *Annual Electric Power Industry Report, Form EIA-861 detailed data files*, <https://www.eia.gov/electricity/data/eia861/> (accessed September 26, 2025).

⁴⁴ In lieu of a Michigan-specific assessment, this citation provides a similar analysis of electrification for New Jersey used as a proxy. Energy Futures Group, *New Jersey's Electric Grid has Headroom to Electrify Heating in Over 1 Million Homes*, <https://energyfuturesgroup.com/wp-content/uploads/2025/03/NJ-Grid-Headroom-for-Electrification-2025-03-07.pdf> (accessed September 26, 2025).

⁴⁵ Increased heat pump adoption will also impact cooling, likely increasing cooling efficiency where existing systems are replaced and reducing summer peak usage. While there could be situations where installing a heat pump adds a cooling load where no central system had been in place previously, the majority of Michigan households (87%) have existing air conditions systems (based on 2020 EIA data, *Highlights for air condition in U.S. homes by state, 2020*, <https://www.eia.gov/consumption/residential/data/2020/state/pdf/State%20Air%20Conditioning.pdf>).

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- 1 • **Massachusetts** – Three Massachusetts utilities (Eversource, National Grid, and Unitil)
2 have approved heat pump rates. Approved in July 2025, Eversource proposed a revenue-
3 neutral heat pump rate with seasonal differentiated pricing for distribution and transmission
4 services. This rate was designed to lower average costs to heat pump customers by 17%
5 compared to standard residential rates.⁴⁶ Eversource also plans to automatically enroll
6 customers in this rate who receive heat pump rebates through MassSave efficiency
7 programs. Both National Grid⁴⁷ and Unitil⁴⁸ heat pump rates apply seasonal adjustments
8 only to distribution charges. Each utility has similar eligibility criteria where customers are
9 eligible for this rate if they use a heat pump to heat some or all of their home. Additionally,
10 these rates are designed to have no financial impact on non-participants, while estimating
11 an average savings of \$540 in reduced heating bills for eligible customers.⁴⁹

- 12 • **Maine** – Two Maine utilities (Central Maine Power, Versant Power) offer seasonal rates
13 aimed at customers with electric heating. Central Maine Power's Rate A-Seasonal is a
14 residential rate for customers with installed heat pumps, currently approved as a pilot and
15 limited to 5,000 customers. This rate provides a seasonal differential for energy charges,
16 set at \$0.01126/kWh in winter (November through April) and \$0.278592/kWh in summer
17 (May through October), compared to the standard residential rate, which is a flat

⁴⁶ Mass. DPU Case No. DPU25-55, Order, July 29, 2025, <https://www.mass.gov/doc/25-55-order/download> (accessed September 26, 2025).

⁴⁷ Mass DPU Case No. DPU 23-150, National Grid Electric Base Distribution Rate Case, <https://www.mass.gov/info-details/dpu-23-150-national-grid-electric-base-distribution-rate-case#summary> (accessed September 26, 2025).

⁴⁸ Mass DPU Case No. DPU 23-81, Fitchburg Gas and Electric Light Company (d/b/a Unitil) Gas Division Base Distribution Rate Case, <https://www.mass.gov/info-details/dpu-23-81-fitchburg-gas-and-electric-light-company-dba-unitil-gas-division-base-distribution-rate-case> (accessed September 26, 2025).

⁴⁹ Mass DPU, *All Electric Utility Customers Will Soon Be Eligible for Heat Pump Discount Rates*, July 29, 2025, <https://www.mass.gov/news/all-electric-utility-customers-will-soon-be-eligible-for-heat-pump-discount-rates> (accessed September 26, 2025).

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\$0.134221/kWh in each month.⁵⁰ It also sets a higher monthly service charge of \$40.55, compared to \$29.19 for its standard rate.⁵¹

Versant Power offers heat pump rates for both residential and business customers for customers with installed heat pumps for space and/or water heating.⁵² These Home Heating Eco rates include seasonal differentiation of delivery service rates where, during the heating season (October through April), there is a declining block structure that reduces the per kWh costs from \$0.11938/kWh to \$0.05154/kWh for any consumption above 600 kWh.⁵³

- **Minnesota** – In March 2025 Xcel Energy received approval for a revised electric space heating rate aimed at making electric space heating more cost competitive with natural gas. Specifically, this rate revision increased accuracy of pricing for customers with air-source heat pumps to better reflect cost of service, reduce operational costs, and increase the accessibility of heat pump adoption.⁵⁴ This rate is designed as a discount to all electric usage from October through May for customers with full electric or dual fuel heat pump

⁵⁰ CMP Seasonal Heat Pump Rate, <https://www.cmpco.com/account/understandyourbill/newseasonalheatpumprate> (accessed September 26, 2025).

⁵¹ CMP Rate A – Seasonal Residential Rate Service tariff sheet, p 24.00, 8th rev, <https://www.cmpco.com/documents/40117/115962041/a-seasonal.pdf/9feb3ff0-4bc1-e5e5-cb51-c3a7c7b130ac?t=1757516170907> (accessed September 26, 2025).

⁵² Versant Power, Heat Pumps & Heat Pump Hot Water Heaters, <https://www.versantpower.com/energy-solutions/heat-pumps/> (accessed September 26, 2025).

⁵³ Versant Power Bangor Hydro District, Rate A-20 tariff sheet, p 4.1, 15th rev, https://www.versantpower.com/docs/default-source/residential-rates-sched/july-1st--2025/rate_a20_resheat.pdf?sfvrsn=a342fc92_1 (accessed September 26, 2025).

⁵⁴ Center for Energy and Environment, *The MN PUC approves new space-heating rates for ASHPs*, March 26, 2025, <https://www.mncee.org/mn-puc-approves-new-space-heating-rates-ashps> (accessed September 26, 2025).

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systems.⁵⁵ The energy charge for customers with space heating is \$0.06/kWh compared to \$0.11/kWh for standard customers.⁵⁶

- **New York** – While not yet approved, there is an open proceeding for ConEd with a proposal for a heat pump rate.⁵⁷ Under this proposal, two rates including seasonal differentiation are proposed (one flat rate, one TOU rate). These rates are also designed to be revenue neutral with no financial shift to nonparticipants, while saving heat pump customers between approximately \$438 and \$508 per year.⁵⁸

Q. Have there been any assessments of customer impacts associated with these similar alternative rate designs for customer heat pump adoption?

A. Yes. The 2025 ACEEE study I discussed in Section III.A. identified offering a heat pump-specific electricity rate as the best approach to increase the adoption of heat pumps and guard against increasing energy bills associated with added electric heating loads. This study found that heat pump installations consistently reduce energy bills for homes with propane or fuel oil but increase energy bills for homes with natural gas.

⁵⁵ ASHP, *Incentives, Rates, & Financing*, <https://www.mnashp.org/incentives-rates-financing> (accessed September 26, 2025).⁵⁵ ASHP, *Incentives, Rates, & Financing*, <https://www.mnashp.org/incentives-rates-financing> (accessed September 26, 2025).

⁵⁶ Xcel Energy, Regular Residential Rate Plan, <https://mn.my.xcelenergy.com/s/billing-payment/residential-rates/residential-plan> (accessed September 26, 2025). ⁵⁶ Xcel Energy, Regular Residential Rate Plan, <https://mn.my.xcelenergy.com/s/billing-payment/residential-rates/residential-plan> (accessed September 26, 2025).

⁵⁷ Rewiring America, *Con Edison heat pump customers missing out on \$131 million in bill savings*, July 9, 2025, <https://www.rewiringamerica.org/newsroom/press-releases/heat-pump-customers-can-save-millions> (accessed September 26, 2025). ⁵⁷ Rewiring America, *Con Edison heat pump customers missing out on \$131 million in bill savings*, July 9, 2025, <https://www.rewiringamerica.org/newsroom/press-releases/heat-pump-customers-can-save-millions> (accessed September 26, 2025).

⁵⁸ NY PSC Case Nos. 25-E-0072 and 25-G-0073, Corrected Direct Testimony of Ron Nelson, <https://documents.dps.ny.gov/public/Common/ViewDoc.aspx?DocRefId=%7BE0ED7897-0000-C615-95C2-BF7FD51CFADA%7D> (accessed September 26, 2025).

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1 The 2023 ESIG report I discussed in Section III.A. assessed the impact of alternative cost-
2 based rate designs for a sample of 80 customers electrifying their heating load. The study
3 found that under standard electricity rates, 100% of these customers increased energy bills,
4 though under scenarios considering TOU and seasonal pricing, all of them could achieve
5 lower energy bills associated with electric heating equipment.

6 **Q: Does that conclude your testimony?**

7 A: Yes, it does.

1 MR. BZDOK: Thank you. At this time, on behalf
2 of MEC and CUB, I would move to bind into the record the
3 direct testimony of Tyler Comings, which I will note have
4 a public version, as well as a confidential version to
5 bind into this confidential transcript. And his
6 testimony, both versions, consist of cover page, a table
7 of contents, 22 pages of questions and answers, and
8 Exhibits MEC-4 through MEC-13, which I move to admit into
9 evidence, with MEC-6C, MEC-11C, and 14C being confidential
10 for admission under seal.

11 JUDGE THOITS: Are there any objections to the
12 admission of this testimony under these exhibits?

13 Hearing none. The direct testimony of Tyler
14 Comings is bound into the confidential record. Exhibit --

15 MR. BZDOK: Thank you, Your Honor

16 JUDGE THOITS: Excuse --

17 MR. BZDOK: Oh, I'm sorry.

18 JUDGE THOITS: Excuse me. And Exhibits MEC-4
19 through MEC-5, MEC-7 through MEC-10, MEC-12 through MEC-13
20 are admitted to the public record, and Exhibits MEC-6C,
21 MEC-11C, and MEC-14C are admitted into the confidential
22 record.

23

24

25

STATE OF MICHIGAN
BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the application of
CONSUMERS ENERGY COMPANY for U-21870
authority to increase its rates for the generation
and distribution of electricity and for other
relief.

DIRECT TESTIMONY OF TYLER COMINGS
ON BEHALF OF
MICHIGAN ENVIRONMENTAL COUNCIL AND
CITIZENS UTILITY BOARD OF MICHIGAN

PUBLIC

September 29, 2025

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I. INTRODUCTION & QUALIFICATIONS

Q. Please state for the record your name, position, and business address.

A. My name is Tyler Comings. I am a Principal Economist at Applied Economics Clinic (AEC), located at 6 Liberty Square, PMB 98162, Boston, MA, 02109.

Q. On whose behalf is this testimony being offered?

A. I am testifying on behalf of Michigan Environmental Council and Citizens Utility Board of Michigan.

Q. Please summarize your experience in the field of utility regulation.

A. I have 19 years of experience in economic research and consulting, 14 of which have focused on the electric utility industry. At Applied Economics Clinic, I focus on energy system planning, costs of regulatory compliance, wholesale electricity markets, utility finance, and economic impact analyses. I have provided testimony before utility commissions on these topics in Arizona, Colorado, the District of Columbia, Hawaii, Indiana, Kentucky, Maryland, Michigan, Missouri, New Jersey, New Mexico, Ohio, Oklahoma, West Virginia, and Nova Scotia (Canada). I am also a Certified Rate of Return Analyst and member of the Society of Utility and Regulatory Financial Analysts (SURFA).

I have provided utility-sector expertise for many public-interest clients including: American Association of Retired Persons, Citizens Action Coalition of Indiana, District of Columbia Office of the People's Counsel, District of Columbia Government, Earthjustice, Energy Future Coalition, Hawaii Division of Consumer Advocacy, Illinois Attorney General, Maryland Office of the People's Counsel, Massachusetts Energy Efficiency Advisory Council, Michigan Agency for Energy, Montana Consumer Counsel, Mountain

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1 Association for Community Economic Development, Nevada State Office of Energy, New
2 Jersey Division of Rate Counsel, New York State Energy Research and Development,
3 Nova Scotia Utility and Review Board Counsel, Rhode Island Office of Energy Resources,
4 Sierra Club, Southern Environmental Law Center, U.S. Department of Justice, Vermont
5 Department of Public Service, and West Virginia Consumer Advocate Division.

6 I was previously employed at Synapse Energy Economics, where I provided expert
7 testimony and reports on coal plant economics and utility system planning. Prior to that, I
8 performed research on consumer finance and behavioral economics at Ideas42 and
9 conducted economic impact and benefit-cost analysis of energy and transportation
10 investments at EDR Group (now EBP).

11 I hold a B.A. in Mathematics and Economics from Boston University and an M.A. in
12 Economics from Tufts University. My full resume is attached as Exhibit MEC-4.

13 **Q. Have you testified before this Commission or as an expert in any other proceeding?**

14 A. I have previously testified before the Michigan Public Service Commission (Commission)
15 in the following cases:

- 16 • Case U-21297 (DTE Electric 2023 rate case)
- 17 • Case U-21193 (DTE Electric 2022 IRP)
- 18 • Case U-21189 (Indiana Michigan 2021 IRP)
- 19 • Case U-20836 (DTE Electric 2022 rate case)
- 20 • Case U-21090 (Consumers Energy 2021 IRP)
- 21 • Case U-20963 (Consumers Energy 2021 rate case)
- 22 • Case U-20697 (Consumers Energy 2020 rate case)

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- 1 • Case U-20591 (Indiana Michigan 2018-19 IRP)
- 2 • Case U-20165 (Consumers 2018 IRP)
- 3 • Case U-20134 (Consumers 2018 rate case)

4 I have also provided expert testimony before utility commissions in 12 other U.S. states,
5 the District of Columbia, and Nova Scotia.

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

7 A. Yes, I am sponsoring the following exhibits:

8	Exhibit MEC-4	Tyler Comings Curriculum Vitae
9	Exhibit MEC-5	Company Response U21870-MNSC-CE-0200(a) and
10		Attachment 1
11	Ex MEC-6C	Company Response U21870-MNSC-CE-0070_ATT_0001_CONF
12	Exhibit MEC-7	Company Response U21870-MNSC-CE-0072(c)
13	Exhibit MEC-8	Company Response U21870-ST-CE-0004_ATT_0004
14	Exhibit MEC-9	Company Response U21870-ST-CE-0004_ATT_0025
15	Exhibit MEC-10	Company Response U21870-MNSC-CE-0071_ATT_0004
16	Exhibit MEC-11C	Company Response U21870-MNSC-CE-0071_ATT_0003
17		CONF
18	Exhibit MEC-12	Company Response U21870-MNSC-CE-0072_ATT_0004
19	Exhibit MEC-13	Company Response U21870-MNSC-CE-0226(b).
20	Exhibit MEC-14C	Company Response U21870-ST-CE-0007_ATT_0001_CONF

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II. SUMMARY

Q. What topics are you addressing in your testimony?

A. I am addressing the following topics:

- I address the risks of further investment in natural gas generation, with a focus on the economics of the Jackson plant. I discuss how the plant is inefficient and more susceptible to upside gas price risk. I also explain that there are stranded cost risks in making capital investments at the plant if assuming it will operate until 2040.
- After a review of the capital projects proposed at the Company's gas plants, I find that costs for two projects at the Jackson plant should be disallowed: one project that relied upon an economic analysis that contained several errors and unreasonable assumptions; and another project that did not provide enough analytical support.

Q. Which Company witnesses' testimony do you discuss in your testimony?

A. I am addressing the testimony and exhibits of Company witness Richard Blumenstock.

Q. What other information provided by the Company did you rely on to prepare your testimony?

A. I relied on the Company's filing and attachments, as well as its responses to data requests.

III. RISKS OF FURTHER CAPITAL INVESTMENT IN THE JACKSON PLANT

Q. Please briefly describe the Company's natural gas combined cycle (NGCC) fleet.

A. The Company owns and operates three natural gas power plants, including

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- 1 • Covert, a 1,090-MW NGCC located in Covert, Michigan. This plant was purchased
- 2 by Consumers in 2023 and originally began operation in 2004.¹
- 3 • Jackson, a 531-MW NGCC located in Jackson, Michigan. This plant was purchased
- 4 by Consumers in 2015 and originally began operation in 2002.²
- 5 • Zeeland, which includes 534 MW of NGCC capacity and 315 MW of combustion
- 6 turbine (CT) capacity located in Zeeland, Michigan. This plant began operation in
- 7 2001.³

8 **Q. When are these plants expected to retire?**

9 A. The Company currently plans on running the Covert plant until 2040, the Jackson plant until

10 2041, and the Zeeland plant until 2041.⁴

11 **Q. Why does this section focus on the Jackson plant?**

12 A. The Jackson plant is the least efficient and most expensive of the three NGCC plants (not

13 including the CT units at Zeeland) to operate. It is therefore more vulnerable to the risks of

14 operating gas plants, such as natural gas price and stranded cost risks.

15 **Q. Why is natural gas price risk a general concern for gas plant operators?**

16 A. Natural gas prices are the main determinant of whether a gas plant is cost-effective to

17 operate. Generally, grid operators decide whether to operate these plants based on their

¹ Direct Testimony of Richard T. Blumenstock, p 7-8.

² Blumenstock Direct, p 7; *2016 Consumers Energy Annual Report*, p 56, retrieved September 24, 2025, from https://s26.q4cdn.com/888045447/files/doc_financials/consumers_annual_reports/2016-Consumers-Energy-Annual-Report.pdf.

³ Blumenstock Direct, p 7.

⁴ *Id.*

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1 variable costs of operation, in terms of dollars per MWh. These costs consist of variable
2 operations and maintenance (O&M) and fuel costs. If located in an independent system
3 operator (ISO), like MISO, these plants are committed and dispatched by the ISO based on
4 their variable costs and where these costs are in relation to other available generators in
5 that region.

6 **Q. Are natural gas prices also a determinant of wholesale energy prices?**

7 **A.** Yes. Wholesale energy prices are closely correlated with gas prices because gas generators
8 are often the price-setting, marginal unit, i.e. the most costly unit dispatched at that hour.
9 As noted in the MISO State of Market report for 2024:

10 Natural gas prices continued to be a primary driver of energy prices.
11 This is expected as fuel costs are the majority of most suppliers'
12 marginal production costs. Competition produces strong incentives
13 for suppliers to offer at their marginal costs so fuel price changes
14 will cause comparable offer price changes.⁵

15 The report also found that natural gas generators set the MISO system-wide price 63
16 percent of the time and, due to congestion, 91 percent of locational marginal prices
17 (LMPs)—even though gas generation only contributed 39 percent of all MISO generation.⁶

⁵ Potomac Economics, *2024 State of the Market Report for the MISO Electricity Markets*, p 4, retrieved September 12, 2025, from https://www.potomaceconomics.com/wp-content/uploads/2025/06/2024-MISO-SOM_Report_Body_Final.pdf.

⁶ *Id.* at p 6.

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1 **Q. Has the Company understated the Jackson plant’s operating costs when assessing its**
2 **“net energy value”?**

3 **A.** Yes. The “net energy value” (or NEV) is the Company’s assessment of the energy costs
4 and revenues for its units—shown in Company exhibit RTB-2. The NEV value is
5 calculated for each unit as the wholesale energy and ancillary revenues minus the variable
6 costs; thus, it is a measure of the incremental dollar value of that unit’s generation. It does
7 not include fixed costs or capacity value.

8 The Company overstates the NEV of the Jackson plant for 2020 through 2024 by assuming
9 lower variable costs than what it reports elsewhere. The Company reported historical fuel
10 costs in filing Attachments 126 B, D, F, and J. These documents also provide “total
11 production costs” which include fuel, variable and fixed O&M.⁷ To isolate variable O&M,
12 the Company pointed to its workpaper W-24, where it stated that these costs were shown
13 in the “major maintenance” line item.⁸ The values shown in black below are the combined
14 fuel and variable O&M as reported by Consumers. In contrast, the values used in the
15 Company’s NEV calculation are shown in grey. The NEV variable costs are clearly lower
16 than those reported by Consumers in every year.

⁷ Ex MEC-5, Company Response U21870-MNSC-CE-0200(a) and Attachment 1.

⁸ *Id.*

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1
2

3 **Q. Did you recalculate the NEV with the fuel and VOM costs shown above?**

4 **A.** Yes. I found that when those costs are used in the NEV, the value for the Jackson plant
5 decreases from \$179.4 million to \$120.7 million—a reduction of one-third of the NEV
6 value for 2020 through 2024.

7 **Q. Would upward pressure on natural gas prices favor natural gas generation?**

8 **A.** It depends. All else equal, higher natural gas prices would increase the costs of natural gas
9 generation, leading it to be dispatched less often. However, this does not happen in a
10 vacuum: a higher natural gas price would also lead to higher energy prices, which would
11 increase energy revenue and make it more advantageous to dispatch gas generators. The
12 heat rate of the unit or plant is another important factor as that measures how efficient it is
13 at converting fuel to electricity—often measured in terms of kWh per btu or MWh per

⁹ Ex MEC-6C, Company Response U21870-MNSC-CE-0070_ATT_0001_CONF; Company Filing Attachments 126 B, D, F, and J; Company workpaper W-24.

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MMBtu. The higher the heat rate, the more fuel is required to produce a unit of power; therefore the less efficient the generator is.

Q. Is the Jackson plant the least efficient and most costly of the NGCC's operated by Consumers?

A. Yes. Over the past five years, the heat rate of Jackson is roughly 15 percent higher than the rate at Covert and Zeeland. This means that Jackson requires about 15 percent more fuel to produce a unit of power than the other two NGCC's. The differences in efficiency have a marked effect on the fuel costs per MWh between the plants, as shown below in Table 1:

Table 1: Fuel Costs at Covert, Jackson, and Zeeland NGCC Plants¹⁰

Metric	NGCC	2020	2021	2022	2023	2024
(A) Fuel Cost (\$/MMBtu)	Covert				\$2.48	\$2.18
	Jackson	\$2.26	\$4.18	\$6.56	\$2.66	\$2.40
	Zeeland	\$1.93	\$3.92	\$6.29	\$2.40	\$2.07
(B) Heat Rate (MMBtu/ MWh)	Covert				7.3	7.2
	Jackson	8.3	8.3	8.6	8.5	8.6
	Zeeland	7.6	7.2	7.2	7.2	7.1
Fuel Cost (\$/MWh) =(A)x(B)	Covert				\$18	\$16
	Jackson	\$19	\$35	\$56	\$23	\$21
	Zeeland	\$15	\$28	\$45	\$17	\$15

The fuel costs shown above are first in terms of per MMBtu (or heat input). On this basis, Jackson has had the highest fuel costs of the three NGCC's in recent years. The plant has also had the highest heat rate, or lowest efficiency. With these two factors compounded,

¹⁰ Energy Information Administration (EIA), Form EIA-923, retrieved July 28, 2025, from <https://www.eia.gov/electricity/data/eia923/>. Data for Covert is only shown for those years that the plant has been under Consumers' ownership.

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the fuel cost on a per MWh basis (equal to fuel cost per MMBtu multiplied by the heat rate) is markedly higher at Jackson compared to Covert or Zeeland each year.

Q. Is there upside or downside risk for gas prices going forward?

A. There is more upside risk. Gas prices were low in 2023 and 2024, but there are upward pressures that are leading to higher price expectations. Primarily, while the U.S. has produced high volumes of natural gas in recent years, it has also significantly increased liquified natural gas (LNG) exports, recently becoming the largest exporter of LNG in the world. Rapid expansion of exports means lower domestic gas supply available as more foreign customers are competing for the same gas. These exports have been historically low but have skyrocketed in recent years. In 2015, only 0.1 percent of total U.S. gas production was exported as LNG (0.08 billion cubic feet per day or “bcf/d”); whereas in 2024, almost 10 percent of gas production was exported as LNG (12 bcf/d).¹¹ Because the volume of gas produced in the US was also increasing, the volume of LNG exports increased by a factor of over 150 in that ten-year period. The total amount of LNG exports *capacity* as of early 2024 was 14.7 bcf/d which means that most of this capacity has been used.

In the past year, another 5.4 bcf/d of export capacity has opened up and another 9 bcf/d is under construction and expected to be online between 2026 and 2029.¹² Thus, LNG export capacity as of early 2024 is expected to double by 2029—based only on projects that are

¹¹ EIA, *U.S. Natural Gas LNG Exports*, retrieved September 16, 2025, from <https://www.eia.gov/dnav/ng/hist/n9133us2A.htm>; EIA, *U.S. Natural Gas Gross Withdrawals*, retrieved September 16, 2025, from <https://www.eia.gov/dnav/ng/hist/n9010us2A.htm>.

¹² EIA, *U.S. Liquefaction Capacity*, retrieved September 16, 2025, from <https://www.eia.gov/naturalgas/importsexports/liquefactioncapacity/U.S.liquefactioncapacity.xlsx>

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1 physically underway. Moreover, another 15.4 bcf/d of LNG export capacity has been
2 approved but is not under construction.¹³ If this came to pass, it would triple the U.S. export
3 capacity level in 2024.

4 With significant expansion of export capacity, U.S. LNG exports are expected to continue
5 to grow and as a result place pressure on domestic gas supply and prices. The Energy
6 Information Administration expects domestic gas prices to nearly double between 2024
7 and 2026 due to “rising LNG exports” and “flattening U.S. natural gas production.”¹⁴ The
8 latest Short-term Energy Outlook (STEO) forecasts a Henry Hub gas price of \$4.30 per
9 MMBtu in 2026 compared to \$2.20 in 2024.¹⁵ Natural gas futures prices for 2026 and 2027
10 are just under \$4 per MMBtu.¹⁶

11 **Q. Is the Jackson plant more vulnerable to gas price increases than a typical NGCC?**

12 **A.** Yes. Sustained upward pressure on gas prices is a major risk for Jackson and other
13 inefficient NGCCs. Given the current and anticipated massive expansion in LNG export
14 terminals and increasing global demand for LNG, the upward pressure on U.S. domestic
15 natural gas prices could be felt in the long-term. This makes Jackson, and other inefficient
16 NGCCs, economically vulnerable because of how sensitive operating costs are to gas price
17 increases. For instance, in 2021 the price of gas at the Jackson plant was \$3.92 per
18 MMBtu—which is close to the futures market’s expected price in the next two years (see

¹³ *Id.*

¹⁴ EIA, *Short-term Energy Outlook (STEO), September 2025*, p 9, retrieved September 16, 2025, from https://www.eia.gov/outlooks/steo/pdf/steo_full.pdf

¹⁵ *Id.*

¹⁶ CME Group, *Henry Hub Natural Gas Futures*, settlement date September 15, 2024, retrieved September 16, 2025, from <https://www.cmegroup.com/markets/energy/natural-gas/natural-gas.html>

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1 Table 1). In that year, the plant's fuel costs alone were \$35 per MWh about 67 percent
2 higher than they were in 2024 when gas prices had dipped.

3 **Q. In addition to gas price risk, is there stranded cost risk with gas generation?**

4 **A.** Yes. By "stranded costs" I am referring to capital costs that have not been recovered in
5 rates at the time of a unit's or plant's retirement. This issue arises when the unit or plant
6 retires before previously planned. These costs can be recovered in rates by accelerating
7 depreciation to meet the earlier retirement date; or recovered through a regulatory asset
8 after retirement; or securitized and recovered after retirement (typically at a lower interest
9 rate); or recovery is not allowed and the utility absorbs the expense; or some combination
10 of these options.

11 The issue of stranded costs has arisen often in the past decade as many coal plants have
12 retired early—some shortly after making major capital investments. The issue should be
13 kept in mind for gas generation going forward, as further capital invested in these
14 generators increases the potential for stranded costs to occur if the gas generation is
15 uneconomic and its retirement is accelerated.

16 **Q. Are you recommending that Jackson be retired earlier than its currently planned**
17 **retirement of 2040?**

18 **A.** No. I am flagging that the Jackson plant is the most economically vulnerable of the three
19 NGCC plants, and thus further investment in the plant should be carefully considered. In
20 next section, I discuss two capital projects at Jackson that should be disallowed because
21 their supporting analyses are highly flawed or lacking.

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1 **IV. CAPITAL COST DISALLOWANCES AT THE JACKSON PLANT**

2 **Q. Please summarize the Company's proposed capital costs at its three gas plants.**

3 **A. In this case, Consumers is requesting rate recovery for \$341.3 million in capital costs at**
4 **the Covert, Jackson, and Zeeland gas plants, including:¹⁷**

5 • Covert: \$26.1 million in the historical test period (January 1, 2024 through
6 December 31, 2024), \$59.3 million in the bridge period (January 1, 2025 through
7 April 30, 2026), and \$54.2 million in the test period (May 1, 2026 through April
8 30, 2027).

9 • Jackson: \$12.2 million in the historical test period, \$22.5 million in the bridge
10 period, and \$24.8 million in the test period.

11 • Zeeland: \$39.7 million in the historical test period, \$64.5 million in the bridge
12 period, and \$38.1 million in the test period.

13 These capital projects were categorized by Consumers as related to infrastructure,
14 operations, regulatory, or reliability.¹⁸ The Company stated that none of the capital projects
15 were required for safety reasons.¹⁹

16 **Q. Which capital projects did you review in this case?**

17 **A. My review started with the capital projects where the requested spending was over \$1**
18 **million at one of the three NGCC plants and for projects that were categorized as related**

¹⁷ Company Filing Attachment 131.

¹⁸ *Id.*

¹⁹ Ex MEC-7, Company Response U21870-MNSC-CE-0072(c).

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1 to “reliability.” I focused on projects where there was an economic assessment of the
2 benefits and costs.

3 **Q. Broadly describe how Consumers conducted economic assessments of capital**
4 **projects.**

5 **A.** Most of the economic assessments I reviewed were for projects intended to address a future
6 mechanical issue at one of the NGCC plants. These projects were justified by Consumers
7 as needed for reliability purposes because there was a chance of further outages or derates
8 (i.e. reduction in capacity) if the project was not done (e.g. Project ID 13573 – purchase of
9 generator step-up replacement at Covert).²⁰ The Company’s economic assessments
10 evaluated the costs and benefits of the project: in some cases, framed as doing the project
11 versus “doing nothing” or, in some cases, versus another alternative project.²¹ The benefits
12 of the project usually included an estimate of the value of energy and/or capacity that would
13 have been lost but-for the project—or put differently, what energy and/or capacity value
14 would be gained by doing the project. On the opposite side of the ledger are the costs which
15 included direct project spending, and sometimes other indirect costs of implementation. If
16 the discounted benefits outweighed the discounted costs, then the project was found to be
17 beneficial—this can be referred to as a benefit-cost or net present value (NPV) analysis.
18 For some assessments, the Company calculated an internal rate of return (IRR) in place of
19 a full benefit-cost or in addition to that analysis.²²

²⁰ Ex MEC-8, Company Response U21870-ST-CE-0004_ATT_0004.

²¹ *Id.*

²² Ex MEC-9, Company Response U21870-ST-CE-0004_ATT_0025.

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1 **Q. How was energy value estimated in the economic assessments?**

2 **A.** If a potential mechanical issue caused a full or partial outage or derate of the plant, it would
3 lose wholesale energy revenue and avoid variable costs—but only assuming it would have
4 operated in the absence of that outage. The Company sometimes estimated the projected
5 energy value as the amount of wholesale revenue that the plant would have generated, or
6 the dollars of energy revenue lost when on an outage. For some projects, the Company
7 conducted modeling of the outage using the Aurora production cost model that produced
8 outputs of MISO energy revenue. In some cases, the Company also accounted for the
9 variable costs of the plant that would also be avoided on an outage. When the energy value
10 was estimated as energy revenues minus the variable costs, it was similar to the Company's
11 NEV calculation that I discussed earlier.

12 **Q. How was capacity value calculated in the economic assessments?**

13 **A.** The Company usually estimated the capacity value per MW-day based on 75 percent of
14 the MISO cost of new entry (CONE). The amount of capacity reduction at the plant due to
15 an outage or de-rate, multiplied by the dollars per MW-day value represented the capacity
16 value. Conversely, if a project added new capacity, then the calculation would work the
17 same way but as a direct benefit rather than an avoided cost.²³

18 **Q. Are these energy and capacity value estimates dependent on assumptions made by the**
19 **Company?**

20 **A.** Yes. As with any modeling or simulation, the final estimates are dependent on the
21 underlying assumptions and methodology. A reasonable methodology can lead to

²³ Ex MEC-10, Company Response U21870-MNSC-CE-0071_ATT_0004.

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1 unreasonable results if the input assumptions are unreasonable. The modeling outputs,
2 using the Company's assumptions, estimate future generation (MWh) of the plant, variable
3 costs, and energy revenues that are used to estimate the energy value. Some of the
4 assumptions used by the Company include: the length of an outage, the amount of capacity
5 that is affected by the outage, wholesale energy prices, variable costs, timing of the outage,
6 heat rate improvement, or capacity improvement or de-rate. However, if some or all of
7 these assumptions are not reasonable, then the energy or capacity value estimate is not
8 reasonable.

9 **Q. Do you recommend the disallowance of costs for any capital projects?**

10 **A.** Yes. I recommend that costs be disallowed for two projects at the Jackson plant. The first
11 project is project ID 13478 - "JGS - Generator Step Up Transformer (GSU) Site Spare,"
12 where the Company is requesting \$1.33 million in the bridge period and \$2.33 million in
13 the projected test period. The second project is project ID 13475, Jackson Plant "LM1-6
14 VIGV(variable inlet guide vane)," where the Company is requesting \$7,885 in the historic
15 test period, \$646,911 in the bridge period and \$960,102 in the projected test period.²⁴ I also
16 found issues with two other projects, though I do not recommend a disallowance for these
17 projects.

18 **Q. Were there any costs allowed into rates for these projects in the last rate case?**

19 **A.** According to the Company's filing in this case, yes. The Company's filing attachment 133
20 shows that \$916,667 for project ID 13478 and \$1,036,667 for project ID 13475 were

²⁴ Company Filing Attachment 131.

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1 approved by the Commission in case U-21585. My recommendation for disallowances
2 only pertains to the incremental costs being requested in this current case.

3 **Q. Please describe the Company's analysis of the Generator Step Up Transformer**
4 **project.**

5 **A.** The Company proposed the project to replace this spare part to avoid "significant loss of
6 power generation, ranging from 47 MW to 104 MW."²⁵ The Company claims that the lead
7 time to get this part is 3 years. But most of the plant would still be available in the event of
8 this equipment's failure.

9 **Q. How did the Company economically assess the project?**

10 **A.** The Company evaluated the project compared to two alternatives: 1) "do nothing", where
11 it assumed there would be a failure leading to a derate of 104 MW, and as a result lose
12 capacity value for those MWs for a three-year period, and a net energy value from not
13 producing energy from those 104 MW's over the same period; and 2) leasing a transformer
14 while repairing the failed one, where there is assumed to be 90-day outage to fix the issue
15 and use the rental equipment.²⁶

16 **Q. Is the energy value during the potential outage overstated in the Company's**
17 **assessment?**

18 **A.** Yes, for a few reasons.

19 First, the Company's analysis of the energy value is taken from Aurora modeling that
20 projects that the Jackson plant would normally operate at between [REDACTED] percent

²⁵ Company exhibit A-45 (RTB-6), p 1.

²⁶ *Id.* at p 8.

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1 capacity factor.²⁷ In the last five years, however, the plant has operated between 31 and 39
2 percent—less than [REDACTED] what is predicted in the economic assessment.

3 Second, the Company assumes the maximum level of de-rate of [REDACTED] MW in its analysis,
4 but the de-rate could be as low as [REDACTED] MW—or less than [REDACTED] the amount assumed
5 when calculating the energy value. Thus, the amount of capacity still capable of producing
6 energy at the plant could be much higher in the event of a failure. But the Company is
7 assuming the worst-case scenario.

8 Finally, the Company estimates that there is only a 5 percent chance of failure that would
9 lead to the loss of power, and that this probability would increase by 5 percentage points
10 each year.²⁸ But this probability was not included in the quantification of energy value.

11 Thus, the alternatives to the project, including “do nothing,” implicitly assumed that the
12 failure happens with 100 percent certainty, rather than having a small chance of happening.

13 In sum, these three assumptions of the capacity factor, level of de-rate, and ignoring the
14 low probability of the outage all lead to a substantial overstatement of the energy value. I
15 am not able to produce a corrected analysis to address these, as I do not have access to the
16 model, but I encourage the Company to address these issues and re-run the model if it
17 wants to seek recovery for this project’s costs.

²⁷ Ex MEC-11, Company Response U21870-MNSC-CE-0071_ATT_0003 CONF.

²⁸ Company exhibit A-45 (RTB-6), p 1.

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1 **Q. Is the capacity value during the potential outage overstated in the Company's**
2 **assessment?**

3 **A.** Yes. The reasons listed above regarding the level of de-rate and probability of an outage
4 also affect the capacity value. The Company assumes 75 percent of CONE capacity value
5 for every ZRC that is not available on a potential outage. Because it assumes that [REDACTED]
6 MW, the maximum nameplate capacity, is lost and that the event has a 100 percent chance
7 of happening, means it is also grossly overstating the capacity value. For instance, if one
8 were to assume only [REDACTED] MW de-rate and a 5 percent chance of happening (followed by
9 an increase of 5 percent in each year), that would be a capacity value of \$1.3 million instead
10 of \$28 million claimed by Consumers.

11 **Q. What costs do you recommend be disallowed for this project?**

12 **A.** I recommend a disallowance of the \$3.66 million bridge and test period costs being
13 requested for this project due to the Company vastly overstating the potential benefits of
14 the project.

15 **Q. Are the benefits or the costs for capital projects more certain?**

16 **A.** The costs are well known and understood while the benefits are highly speculative. The
17 Company has partially addressed this by stating the probability of failure under a “do
18 nothing” scenario for some projects. However, to my knowledge, it has not directly
19 incorporated these probabilities when calculating the projects' benefits. This leaves the
20 benefit-cost analyses—for projects that address low-probability failures—to be lopsided in
21 favor of benefits. Thus, the Company is more likely to greenlight the project even though
22 its benefits are vastly overstated and uncertain.

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1 **Q. Please describe the Company’s analysis of the Variable Inlet Guide Vane project.**

2 A. Project ID 13475, Jackson Plant “LM1-6 VIGV(variable inlet guide vane)” involves
3 installing equipment to increase the plant’s efficiency and improve performance.²⁹ The
4 Company’s support for the project relies on estimates of avoided repairs as well as fuel
5 savings and increased energy value from the assumed efficiency gain.

6 **Q. Did the Company provide adequate support for the estimated benefits for gaining**
7 **efficiency?**

8 A. No. The Company estimated the energy value of this upgrade (or the cost of not doing the
9 upgrade) at \$29.6 million, mentioning that it used the Aurora model to develop this
10 figure.³⁰ The final estimates is presented in the original scope document; but the Company
11 did not provide a workbook showing the derivation of these calculations, as it did for other
12 projects that used Aurora model outputs. When asked if there was further documentation
13 in support of the project, apart from the original scope document, the Company confirmed
14 that there were none.³¹ Because there of a lack of analytical support provided, I am
15 recommending that the costs of this project be disallowed.

16 **Q. Did you have concerns with other economic analyses?**

17 A. Yes. I found issues with two others projects:

- 18 • Project ID PP-00554, Jackson Plant “1-6 Feedwater Desuperheater Valve”: This
19 project involves installing a feedwater control valve to prevent degradation of
20 existing valves. The scope document for this project mentions a “replacement

²⁹ Ex MEC-12, Company Response U21870-MNSC-CE-0072_ATT_0004.

³⁰ *Id.* at p 6-7.

³¹ Ex MEC-13, Company Response U21870-MNSC-CE-0226(b).

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1 power cost” if the Company does not conduct the project; this assumes an outage
2 to repair the damaged valves during which the unit will forego energy revenue
3 only—assuming an LMP of \$30 per MWh.³² This figure does not account for the
4 savings of variable costs, primarily fuel, if the unit were not generating power.
5 Because these replacement power costs were not directly factored into the decision,
6 I am not recommending a disallowance for this project.

- 7 • Project ID 6593, Zeeland Plant “Phase I Gas Turbine Upgrades” as part of the
8 Zeeland Long Term Service Agreement - Running Capital Contract: The economic
9 analysis has an error by calculating the capacity value as [REDACTED] percent of CONE
10 instead of the intended [REDACTED] percent value.³³ Making this adjustment alone does
11 not change the direction of the analysis, therefore I am not recommending a
12 disallowance for this project.

13 **Q. Do you have general recommendations for providing supporting documentation of**
14 **economic assessments?**

15 A. Yes. If the Company calculates energy value for the project, then the underlying
16 calculations need to be explicitly shown. There were many projects where the final estimate
17 was provided in the project scope documents, but the underlying calculation was not
18 provided. Even in cases where the Company provided a separate workbook that showed
19 calculations, these contained hard-coded model outputs. The Company should provide the
20 maximum level of transparency, including providing access to any model used.

³² Ex MEC-9, Company Response U21870-ST-CE-0004_ATT_0025, p 1.

³³ Ex MEC-14C, Company Response U21870-ST-CE-0007_ATT_0001_CONF.

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1 **V. RECOMMENDATIONS**

2 **Q. Please summarize your conclusions and recommendations to the Commission.**

3 **A. I recommend that the Commission:**

- 4 1. Disallow \$3.67 million in capital costs for the Jackson Plant Generator Step-
- 5 up project.
- 6 2. Disallow \$1.61 million in capital costs for the Jackson Plant Variable Inlet
- 7 Guide Vane (VIGV) project.
- 8 3. Require that Consumers also calculate the benefits of a project that include
- 9 the probability of an outage occurring from not doing the project.
- 10 4. Require that Consumers provide more transparency with economic
- 11 assessment calculations, including access to any models used in such
- 12 calculations and auditable derivations of calculations done outside of those
- 13 models.

14 **Q. Does that complete your testimony?**

15 **A. Yes.**

1 MR. BZDOK: Thank you. I'm sorry to jump you
2 there.

3 At this time, I would move to bind into the
4 record on behalf of MNSC, the public and confidential
5 direct testimony of Caroline Palmer, which consists of a
6 cover page, a table of contents, 33 pages of questions and
7 answers, and I would move to admit into the record
8 Exhibits MEC-15 through MEC-23.

9 JUDGE THOITS: Are there any objections to the
10 admission of this testimony or these exhibits?

11 Hearing none. The direct testimony of Caroline
12 Palmer is bound into the confidential record, and Exhibits
13 MEC-15 through MEC-23 are admitted.

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STATE OF MICHIGAN
BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the application of
CONSUMERS ENERGY COMPANY for U-21870
authority to increase its rates for the generation
and distribution of electricity and for other
relief.

DIRECT TESTIMONY OF CAROLINE PALMER
ON BEHALF OF
MICHIGAN ENVIRONMENTAL COUNCIL,
NATURAL RESOURCES DEFENSE COUNCIL, SIERRA CLUB,
AND CITIZENS UTILITY BOARD OF MICHIGAN

PUBLIC

September 30, 2025

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I. INTRODUCTION & QUALIFICATIONS

Q. Please state for the record your name, position, and business address.

A. My name is Caroline Palmer. I am a Principal Associate at Synapse Energy Economics, Inc. (“Synapse”), located at 485 Massachusetts Avenue, Suite 3, Cambridge, MA 02139.

Q. On whose behalf is this testimony being offered?

A. I am testifying on behalf of the Michigan Environmental Council, Natural Resources Defense Council, Sierra Club, and Citizens Utility Board of Michigan.¹

Q. Please summarize your experience in the field of utility regulation.

A. At Synapse, I provide expert witness and consulting services on behalf of public interest clients in regulatory proceedings. The issues I cover in these cases include marginal and embedded cost-of-service studies, revenue allocation, advanced rate design, low-income rate design, large load/data center tariff design, decoupling, distributed energy resource (“DER”) interconnection and compensation, and electric vehicle (“EV”) infrastructure investments. Prior to joining Synapse, I worked at Strategen Consulting for five years performing similar work. I have submitted expert testimony in 20 dockets across ten jurisdictions.

I was awarded a Fulbright Research Fellowship to Greece in 2015 and supported clean energy policy consulting at Meister Consultants Group (now Cadmus) before that. I hold a Master of Public Policy from the Goldman School at UC Berkeley and a Bachelor

¹ Sierra Club joins my testimony with respect to data centers.

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1 of Science from Georgetown University. I have 10 years of professional experience. My
2 work experience is summarized in my resume, provided as Exhibit MEC-1.

3 **Q. Have you testified before this Commission or as an expert in any other proceeding?**

4 A. I have previously testified before the Michigan Public Service Commission (Commission)
5 in the following case:

- 6 • Case U-21859 (Consumers Energy's application to serve data center load on its
7 Large General Service Primary Demand ("GPD") Rate)

8 I have also sponsored testimony before the Connecticut Public Utilities Regulatory
9 Authority, the New Hampshire Public Utilities Commission, the Missouri Public Service
10 Commission, the New York Public Service Commission, the Massachusetts Department of
11 Public Utilities, the Maine Public Utilities Commission, the Oklahoma Corporation
12 Commission, the North Carolina Utilities Commission, and the Nova Scotia Energy Board.

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

14 A. Yes, I am sponsoring the following exhibits:

15 Exhibit MEC-15 Resume of Caroline Palmer

16 Exhibit MEC-16 Consumers Response to U21870-MNSC-CE-221

17 Exhibit MEC-17 Consumers Response to U21870-MNSC-CE-0222

18 Exhibit MEC-18 Consumers Response to U21870-MNSC-CE-0214

19 Exhibit MEC-19 Consumers Response to U21870-MNSC-CE-253 with
20 Attachment 1

21 Exhibit MEC-20 Consumers Response to U21870-MNSC-CE-255 without
22 Attachments

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1 Exhibit MEC-21 Consumers Response to U21870-MNSC-CE-256

2 Exhibit MEC-22 Consumers Response to U21870-MNSC-CE-257

3 Exhibit MEC-23 Consumers Response to U21870-MNSC-CE-215

4 **Q. What topics and Company witnesses' testimony are you addressing in your**
5 **testimony?**

6 **A.** I am addressing the Company's cost of service study and rate design and the testimony of
7 Company witnesses Davis and Connolly.

8 **II. SUMMARY OF CONCLUSIONS AND RECOMMENDATIONS**

9 **Q. Please summarize your conclusions.**

10 **A.** My conclusions are as follows:

- 11 • The Company's classification of advanced metering infrastructure ("AMI") meter costs
12 as 100 percent customer-related does not reflect cost causation.
- 13 • Consumers' cost of service study ("COSS") disproportionately and inappropriately
14 assigns distribution costs to lower voltage or smaller customers.
- 15 • The riskiness and magnitude of infrastructure investment associated with potential new
16 data centers taking service in Consumers' territory necessitates re-evaluating the
17 traditional ways that Consumers would track and allocate the costs of its investments
18 for data centers.
- 19 • Consumers' proposed facilities allowance for the Large Economic Development Rate
20 ("LEDRA") could increase costs for other customers.

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1 **Q. What are your recommendations?**

2 A. I recommend that the Commission:

- 3 • Direct the Company to classify AMI meters as customer, demand, and energy related
4 proportionally to the relative benefits that accrue to each of the three cost drivers based
5 on Consumers' quantification of AMI benefits.
- 6 • Reject Consumers' proposed new distribution COSS allocations to downstream-
7 voltage customers. Further, the Company should reconsider existing voltage
8 differentiations already built into its COSS, with related recommendations in its next
9 rate case.
- 10 • Require Consumers to allocate distribution battery costs to all distribution customers
11 and allocate Multi-Account Online Account Management project costs to the customer
12 classes who use the program.
- 13 • Order Consumers to demonstrate in its next rate case that its proposed cost allocation
14 methods satisfy the legislative requirement that residential customers will not subsidize
15 the costs incurred to provide electric service to a data center.
- 16 • Order Consumers to conduct sensitivity modeling runs in its next IRP with and without
17 data center load and disclose the difference in revenue requirements and resource
18 portfolios.
- 19 • Reject Consumers' proposed facilities allowance for rate LEDR. If the Commission
20 approves a facilities allowance, it should reject Consumers' proposal to provide the
21 facilities allowance to existing customers and should require Consumers to true up
22 incremental distribution charges for overestimated facilities allowances.

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- Direct Consumers to increase the LEDR system contribution charge and shorten the LEDR discount period.

III. COST OF SERVICE STUDY

Overview of Cost of Service Studies

Q. What is the purpose of a cost of service study?

A. A COSS seeks to determine what costs are incurred to serve each class of customers in order to assign the utility's revenue requirement to each customer or rate class in proportion to the costs that those customers impose on the system.

Q. How is a COSS performed?

A. A COSS typically follows three steps. First, costs are functionalized by separating utility plant and expenses according to the primary functions they serve, such as generation, transmission, and distribution. Second, the functionalized rate base and operating costs are classified based on their primary cost drivers – typically as energy-related (commodity), demand-related (capacity), or customer-related. Finally, costs are either directly assigned to specific customers or allocated among customer classes using allocation factors based on energy use, peak demand, or customer counts.

Q. How do analysts determine the appropriate approaches to cost classification and allocation?

A. When selecting classification factors or allocators, the goal is to fairly allocate costs among different customer classes based on cost causation. Cost causation reflects the notion that the customer or set of customers that caused a cost should pay for the cost. To determine

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1 cost causation, analysts often rely on economic theory and power system engineering
2 considerations.

3 **Q. In your view, has the Company selected appropriate COSS methods?**

4 A. No. I have two primary concerns with the Company's COSS methods:

- 5 1. The Company's meter classification does not reflect AMI cost causation; and
- 6 2. The Company's allocations based on voltage differentiation do not reflect modern
7 cost causation.

8 My testimony recommends alternative approaches that are better supported by economic
9 theory and power system engineering.

10 **Q. How should COSS results be used in a rate case?**

11 A. Parties and the Commission should exercise judgement when using a utility COSS to
12 inform revenue allocation or rate design, as it is an inherently imprecise tool in which cost
13 analysts make numerous subjective determinations that may dramatically impact the study
14 results. As such, utility cost of service studies should be one of several considerations used
15 to guide decision-makers in revenue allocation and rate design, rather than being viewed
16 as the sole determinant or final authority.

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1 ***Consumers Should Classify and Allocate Advanced Metering Infrastructure Meter***
2 ***Costs Based on Customer, Energy, and Demand***

3 **Q. Describe the extent of AMI meter deployment in the Company's territory.**

4 A. As of 2024 reporting, 99.48% of residential, 98.46% of commercial, and 9.91% of
5 industrial customers had AMI meters.² In terms of infrastructure investment, AMI meters
6 made up 68% of the Company's meter plant in service in 2023.³

7 **Q. How does the Company classify and allocate AMI meter costs?**

8 A. Consumers classifies AMI meter costs as customer-related and allocates them using
9 allocator 170, which is based on the number of customers in each customer class. For
10 traditional meters, this approach follows the principle of cost causation by recognizing that
11 the weighted number of customers in a class drives traditional meter costs.

12 **Q. What are your concerns with Consumers' AMI meter classification and allocation?**

13 A. Consumers' approach does not reflect the realities of an evolving power system.
14 Technology and cost responsibility are changing rapidly to meet evolving market demands
15 and to support state policy goals. Technological advances are impacting the services
16 provided on the power grid and how those services are provided, which requires utilities to
17 re-evaluate cost allocation issues that may previously have been considered settled.
18 Traditional cost of service techniques do not necessarily reflect the modern power system
19 or a modernized understanding of cost causation on the system.

² Exhibit MEC-15, Consumers Response to U21870-MNSC-CE-0221(a).

³ Exhibit MEC-15, Consumers Response to U21870-MNSC-CE-0221(c).

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1 The Regulatory Assistance Project explains that the main purpose of meters was
2 once customer billing, but that “advanced meters serve a broader range of functions,
3 including demand management, which in turn provides system capacity benefits, and line
4 loss reduction, which provides a system energy benefit. This means the benefits of these
5 meters flow beyond individual customers, and logically so should responsibility for the
6 costs.”⁴

7 **Q. Do Consumers’ new AMI meters enable services beyond customer-related functions?**

8 A. Yes. Consumers’ AMI meters – an essential component of its overall AMI system – will
9 enable significant new functionality beyond that associated with traditional meters.
10 Consumers identified that AMI benefits include reduced energy theft, peak demand
11 reduction, and energy consumption savings.⁵ For example, AMI-enabled programs
12 “provide customers options to manage their energy usage and their energy costs,” and “all
13 customers benefit through lower power supply costs enabled by reduced capacity
14 requirements during ‘critical peak’ conditions.”⁶

15 **Q. Do these new functionalities and their associated benefits change cost causation for**
16 **AMI meters compared to traditional meters?**

17 A. Yes. The benefits that Consumers described clearly extend the role of AMI meters beyond
18 traditional metering, which does not enable energy savings and demand reductions in this
19 way. The Company proposed, and the Commission approved, its AMI investment based

⁴ Lazar, J. et al., *Electric Cost Allocation for a New Era: A Manual*. Montpelier, VT: Regulatory Assistance Project (2020) p.18.

⁵ Direct Testimony of David E. Schonhard. Case No. U-15645 (Remand), January 2014, p.12.

⁶ *Id.* at 11-12.

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1 on the services AMI would provide.⁷ Thus, cost causation for AMI investments is dictated
2 by those services and benefits.

3 **Q. How do you recommend that Consumers classify AMI meter costs?**

4 A. The Company should identify the AMI meter costs included in its approved revenue
5 requirement and classify those costs as a combination of customer, demand, and energy,
6 because AMI meters provide services and benefits that can be categorized into each of the
7 three cost drivers. Specifically, Consumers should classify AMI meter costs across those
8 categories proportionally according to the relative benefits that accrue to each of the three
9 cost drivers, based on the Company's formal quantification of AMI benefits.

10 **Q. What are Consumers' proportional energy, demand, and customer AMI benefits?**

11 A. The Company last filed an AMI business case in Case No. U-21389.⁸ Of total expected
12 electric smart grid program benefits, demand-related benefits⁹ total 17%, while energy-
13 related benefits¹⁰ total 36%.¹¹ Therefore, I propose an initial classification approach that
14 treats AMI meter costs as 36% energy-related, 17% demand-related, and 47% customer-
15 related. I also recommend that Consumers continue to produce its AMI business case
16 benefit analysis in subsequent rate cases and update this classification accordingly.

⁷ For example, in the October 7, 2014, Case No. U-15645 Order and in subsequent rate cases, in which Consumers has also presented a business case for AMI benefits and costs.

⁸ Exhibit MEC-16, Consumers Response to U21870-MNSC-CE-0221(e).

⁹ AC Load Control Avoided Generation, Transmission and Demand Response Avoided Generation, Transmission.

¹⁰ Theft Reduction, AMI Induced Conservation & Efficiency Energy, and Demand Response Conserved Energy.

¹¹ Exhibit A-72 (JRC-1) in U-21389.

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Q. What is the impact of your recommended AMI meter treatment on COSS allocators?

A. This alternative classification reduces the costs treated as customer-related, instead treating portions as energy- and demand-related. Table 1 compares customer, demand, and energy allocators from Consumers' COSS with my proposed AMI meter allocator, showing that demand and energy allocators tend to allocate fewer costs to small customers and greater costs to larger customers than the 100% customer allocator does, due to larger users' higher utilization of the power system and relatively lower customer count. For example, the weighted customer allocator allocates 60% of costs to the residential class, whereas the energy allocator would only allocate 43% of costs to the residential class. My proposed AMI allocator, shown in the bottom row of the table, would ultimately allocate 52% of AMI costs to the residential class, as it uses a blend of the other three allocators.

Table 1: Customer, Demand, and Energy Allocators for AMI Allocation

Allocator	Total Electric	Residential	Commercial Secondary	Lighting & Unmetered	Primary	Rate GSG
Weighted Customer (170)	100	60.2	28.6	0.1	11.1	0.0
Energy @ Generation (100)	100	42.8	23.8	0.6	32.3	0.6
Class Pk @ Voltage 1 (127)	100	47.6	22.2	0.4	29.2	0.6
AMI Meter Allocator	100	51.8	25.8	0.3	21.8	0.3

Q. Have you implemented your proposal in the Company's COSS to determine its impact on Consumers' COSS results?

A. No, the Company's COSS does not readily permit the testing of changes at this level of granularity.. Thus, the Company is best qualified to adapt its model to include this new classification and allocation approach if the Commission approves it. As discussed above, the new approach would allocate fewer costs to small customers and greater costs to larger

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1 customers than the customer allocator does, due to larger users' higher utilization of the
2 power system and relatively fewer customers.

3 **Q. Have other Commissions approved similar AMI meter classifications?**

4 A. Yes. The Maryland Public Service Commission approved "a benefits approach for
5 allocating AMI costs among rate classes" in 2016, when it approved a proposal to assign
6 25% of AMI costs using a customer-based allocator, 37.5% using a demand-based
7 allocator, and 37.5% using an energy-based allocator in Pepco's distribution rate case.¹²
8 The approved proposal was based on the fact that an early report on AMI benefits assigned
9 just over 75 percent of the benefits to energy and demand management outcomes, justifying
10 a customer, demand, and energy based allocation.¹³ The Maryland Public Service
11 Commission concluded that the "hybrid approach most fairly spreads the costs and related
12 benefits of AMI throughout the Pepco service territory."¹⁴

13 **Q. Does Maryland continue to use a composite allocator for AMI meters?**

14 A. Yes. The Maryland Public Service Commission ordered Baltimore Gas and Electric
15 Company ("BGE") to update its electric AMI benefit analysis in its 2023 rate case to ensure
16 that the AMI allocators reflect updated benefit weights. BGE analyzed six years of data

¹² In the Matter of the Application of Potomac Electric Power Company for Adjustments to Its Retail Rates for the Distribution of Electric Energy (Hereafter, "MD PSC, Case No. 9418"), Order No. 87884. November 15, 2016. (Accessed September 30, 2025) <https://www.psc.state.md.us/wp-content/uploads/Order-No.-87884-Case-No.-9418-Pepco-Rate-Case-1.pdf>. At 105-106.

¹³ MD PSC, Case No. 9418. Direct Testimony of Shelley Norman. July 6, 2016. Available at <https://webpscxb.psc.state.md.us/DMS/case/9418> Item No. 33. At 21-23.

¹⁴ MD PSC, Case No. 9418. Order No. 87884. November 15, 2016. Available at <https://www.psc.state.md.us/wp-content/uploads/Order-No.-87884-Case-No.-9418-Pepco-Rate-Case-1.pdf>. At 106.

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and proposed to allocate 56% of AMI meters based on the replacement cost of AMI meters (customer), 26% based demand, and 18% based on energy.¹⁵

Q. Has the Colorado Public Utilities Commission also approved AMI meter classification as more than customer-related?

A. Yes. In Proceeding No. 23AL-0243E (and in at least two prior rate cases), Public Service Company of Colorado functionalized 17% of Advanced Meter costs as secondary distribution (classified as demand-related), with the remaining 83% functionalized as metering (classified as customer-related).¹⁶

In its February 2024 decision, the Commission found that “there are system-wide benefits of AMI that should be better reflected in the allocation” and therefore directed the Company to “provide a more robust analysis of these costs and identification of the scale and proper allocation of benefits associated with AMI when it files its next Phase II rate case.”¹⁷

¹⁵ Baltimore Gas and Electric Company's Application for an Electric and Gas Multi-Year Plan. Case No. 9692. Direct Testimony of April M. O'Neill. February 17, 2023. Available at <https://webpscxb.psc.state.md.us/DMS/case/9692> Item No. 1. At 15-17.

¹⁶ Colorado Public Utilities Commission Docket No. 23AL-0243E. Rebuttal Testimony Derek S. Klingeman, p.29-31.

¹⁷ Colorado Public Utilities Commission Docket No. 23AL-0243E. February 7, 2024. 2023 CO Phase II Electric Rate Review Decision No. C24-0117, p.23.

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1 **Q. Is there other established regulatory precedent tying cost allocation to benefits?**

2 A. Yes. The Federal Energy Regulatory Commission (FERC) has also determined that “the
3 cost causation principle provides that costs should be allocated to those who cause them to
4 be incurred and those that otherwise benefit from them.”¹⁸

5 Given that the benefits of peak demand reduction accrue to customers by reducing
6 their share of demand-related system costs, the costs of Consumers’ AMI meters are partly
7 attributable to enabling peak demand reduction and should in turn be allocated among
8 customer classes based on demand allocators. The same is true for energy-related benefits.

9 ***Consumers’ Voltage Differentiation Does Not Reflect Cost Causation and May***
10 ***Disproportionately Allocate Costs to Lower-Voltage Classes***

11 **Q. What do you discuss in this section?**

12 A. I discuss a few ways in which Consumers’ COSS disproportionately and inappropriately
13 assigns distribution costs to lower voltage or smaller customers. In subsections 1 and 2, I
14 address the Company’s proposals to strictly identify and assign lower-voltage equipment
15 specifically to lower-voltage customers and provide alternative recommendations. In
16 subsection 3, I address Consumers’ assignment of certain IT project costs to residential
17 customers.

¹⁸ FERC’s influential Order No. 1000 reformed the Commission’s electric transmission planning and cost allocation requirements. *See* Order No. 1000, Transmission Planning and Cost Allocation by Transmission Owning and Operating Public Utilities. 136 FERC ¶ 61,051 paragraph 535. Available at: <https://www.ferc.gov/sites/default/files/2020-04/OrderNo.1000.pdf>.

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1 *1. Distribution Land, Lines, Substations*

2 **Q. How has Consumers further differentiated allocation by voltage in this case?**

3 A. Since its last rate case, the Company updated its property accounting reporting system to
4 map assets to more granular COSS categories than previously identified. The property
5 accounting system produces the Electric Asset Categorization (“EAC”) report, which
6 breaks out distribution plant and related depreciation accounts into more detailed categories
7 “to facilitate allocating costs to customers.”¹⁹ Consumers then updated its COSS
8 distribution cost categories for land, lines, and substation assets to align with the EAC
9 report results.²⁰ Consumers states that these categories were “chosen to capture asset
10 voltage and the downstream facilities connected to/relying on that asset.”²¹ In other words,
11 the Company developed such granular categories in order to allocate costs to downstream
12 connected facilities that rely on a given asset and “should be assigned some of those
13 costs.”²² The update now allows Consumers to isolate lower-voltage infrastructure costs
14 and assign them specifically to downstream customers.²³

¹⁹ Direct Testimony of Emily A. Davis, p.8.

²⁰ For example, Consumers previously separated high voltage distribution substations and equipment into Voltage 1 and below, and Voltage 2 and below; now, Consumers separates high voltage distribution substations and equipment into Voltage 1 only, Voltage 2 and below, and Voltage 3 and below. *See* Davis Direct, p.7 and 10.

²¹ Davis Direct, p.9.

²² Davis Direct, p.10-11.

²³ Consumers also created two new allocators that assign limited costs specifically to Voltage 1 and Voltage 2.

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1 **Q. Why does Consumers assign lower-voltage infrastructure costs to downstream**
2 **customers?**

3 A. Historically, Consumers has excluded customers taking service at higher voltage levels
4 from cost allocation for certain infrastructure to account for the fact that, in the past, such
5 customers did not contribute to system costs at lower voltage levels. The theory supporting
6 such differentiation is that higher voltage customers do not benefit from the lower voltage
7 distribution network because power flows in one direction (from high to low voltage).
8 However, the justification for isolating cost assignment to downstream voltages—
9 especially at the increasing granularity that Consumers now proposes—is becoming less
10 pertinent as the power system evolves.

11 **Q. Why has the historical justification for strict cost assignment to downstream voltages**
12 **changed in today's evolving power system?**

13 A. One-way power flow is no longer the reality. Today, the power system is changing such
14 that DERs are making bidirectional power flow more common on the distribution system,
15 in turn providing generation and other services to higher voltage customers who previously
16 only benefitted from centralized generation delivered at the transmission or primary level.

17 **Q. Has Consumers acknowledged bidirectional power flow on its distribution system?**

18 A. Yes. Consumers' Reliability Roadmap, updated for this proceeding, describes "[b]i-
19 directional power flows, especially in circuits that show a propensity to higher-than average
20 adoption of solar DG."²⁴ Consumers anticipates between 2.4 and 3.5 GW of solar DG

²⁴ Exhibit A-129 (MPK-19), p.34.

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1 penetration by 2030, causing “two-way flows.”²⁵ Consumers also justifies the importance
2 of a DER Management System (“DERMS”) in part based on the described bidirectional
3 power flow, calling a DERMS “critical for managing bi-directional power flows.”²⁶

4 Clearly, Consumers is increasingly planning and designing its power system to be
5 bidirectional. In fact, the Company expects to produce reports in the future demonstrating
6 the extent of bi-directional power flow. To do so, Consumers would assess reverse flow
7 through primary distribution lines and devices as well as substation devices.²⁷ The
8 Company’s plan to assess reverse flow at various levels of the power system indicates the
9 potential pervasiveness of the phenomena.

10 **Q. Do higher voltage customers benefit from the lower voltage system?**

11 A. Yes. Due to bidirectional power flows, lower voltage assets are now being used to serve
12 some of the requirements of higher voltage customers; therefore, higher voltage customers
13 benefit from (and thus help cause) costs related to low voltage assets, and should pay a fair
14 share of these costs. Indeed, Consumers agrees that bidirectional flows may include
15 flowing from lower-voltage distribution equipment to higher-voltage distribution
16 equipment²⁸ and that there could even be times when power flows from distribution-level
17 equipment to transmission-level equipment.²⁹

²⁵ *Id.* at 35.

²⁶ *Id.* at 142.

²⁷ Exhibit MEC-17, Consumers Response to U21870-MNSC-CE-0222(a).

²⁸ Exhibit MEC-17, Consumers Response to U21870-MNSC-CE-0222(b).

²⁹ Exhibit MEC-17, Consumers Response to U21870-MNSC-CE-0222(c).

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1 **Q. Do you agree with Consumers' new EAC report and resulting COSS allocators?**

2 A. No. Stricter assignment of costs to downstream-voltage customers does not reflect
3 customers' use of the power system, since two-way power flows are becoming more
4 common, with generation being injected into the grid even at low voltages. Thus, most of
5 the new EAC categories and corresponding COSS allocations of all low-voltage resources
6 strictly to low-voltage customers introduce a false precision that is no longer fully
7 representative of reality and is thus unreasonable and out of sync with the changing grid.

8 **Q. What do you recommend regarding Consumers' new EAC report and resulting**
9 **COSS allocators?**

10 A. I recommend that the Commission reject Consumers' proposed new distribution COSS
11 allocations to downstream-voltage customers based on the updated EAC report. New EAC
12 categories that specifically isolate high-voltage costs, such as Consumers' new V1 and V2-
13 only allocators, do not necessarily fit this description and may be appropriate. Further, the
14 Company should reconsider existing voltage differentiations already built into its COSS,
15 with related recommendations in its next rate case. As the Company develops analysis of
16 bidirectional flow on its power system, it should incorporate such empirical data into the
17 EAC report or other power system mapping to identify the extent to which higher-voltage
18 customers utilize and should pay for downstream assets.

19 2. *Distribution Batteries*

20 **Q. How does Consumers allocate distribution batteries?**

21 A. Consumers categorized 100% of the distribution batteries as low voltage distribution
22 ("LVD"), meaning they are allocated only to low voltage customers (in this case, voltage

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level 3 and 4).³⁰ Consumers justifies this allocation as being consistent with the way the COSS treats other demand-related distribution plant and allocates costs to the customer classes connected to (or downstream of) the voltage level of that equipment.³¹

Q. Is it reasonable to allocate distribution battery costs only to LVD customers?

A. No. the Company has not demonstrated that batteries serve only low voltage customers. Consumers is also “not aware of any engineering literature or manuals that specifically state” that batteries serve only voltage level 3 and 4 customers.³² In fact, rather than serving only low voltage customers, distribution-related battery plant provides services that benefit customers across all distribution voltage levels: Consumers notes that such investment is “deployed to support the electric distribution system (e.g., capacity deferral, voltage support, resiliency, etc.).”³³ Thus, the allocation of battery costs should not be limited to lower-voltage customers.

Q. How do you recommend allocating distribution batteries?

A. I recommend that Consumers allocate distribution battery costs to all distribution customers.

³⁰ Davis Direct, p.11.

³¹ Exhibit MEC-18, Consumers Response to U21870-MNSC-CE-0214(a).

³² Exhibit MEC-18, Consumers Response to U21870-MNSC-CE-0214(a).

³³ Exhibit MEC-18, Consumers Response to U21870-MNSC-CE-0214(a).

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1 3. *Digital Customer Operations*

2 **Q. Describe Consumers’ proposal for allocating Commercial and Industrial (“C&I”)**
3 **Online Account Management project costs.**

4 A. In Case No. U-20963, the Commission required that the Company’s COSS separate out
5 and allocate the costs associated with Digital Customer Operations IT projects, including
6 the C&I Online Account Management project.³⁴ Since then, Consumers has changed the
7 project scope and name. It is now known as the Multi-Account Online Account
8 Management (“MAOAM”) project and has expanded to give all customers (including
9 residential customers) the ability to manage multiple accounts through a single login. Thus,
10 the Company “believes it should be allocated in the same manner as other IT projects,” i.e.
11 to all customer classes, negating the need to breakout costs in the COSS.³⁵

12 **Q. Is it reasonable to allocate MAOAM project costs to all customers at this time?**

13 A. No. Consumers justifies its proposed allocation by stating that the project “will support
14 customers across various rate classes;” however, the Company has not demonstrated that
15 all classes will use the software proportionally to the proposed cost allocator. For example,
16 although all customers might have the ability to manage multiple accounts through a single
17 login, it is unclear that the residential class requires such functionality. Currently, there are
18 no customers with MAOAM login for multiple accounts as the tool is still in development,
19 and only C&I customers have access to and use the current tool.³⁶ Yet, the Total Labor
20 (502) allocator that Consumers proposes to use to allocate \$0.64 million in MAOAM plant

³⁴ Davis Direct, p.14.

³⁵ Davis Direct, p.15-16.

³⁶ Exhibit MEC-23, Consumers Response to U21870-MNSC-CE-0215(b).

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and expense³⁷ would assign the majority of these costs to residential customers, per Table

2.

Table 2: Consumers' Proposed Allocator for MAOAM Project Costs

	Total Electric	Residential	Commercial Secondary	Lighting & Unmetered	Primary	Rate GSG
Total Labor (502)	100	62.7	24.0	0.7	12.4	0.2

Q. How do you recommend allocating MAOAM project costs?

A. I recommend that Consumers continue to break out this project cost in the COSS and allocate it to the customer classes who use the program, based on the proportion of customers that have multiple logins. Currently, that would only include C&I customers.

Data Center Cost Allocation

Q. Has Consumers proposed to serve large new data center load?

A. Yes. In U-21859, Consumers proposed changes to its Large General Service Primary Demand ("GPD") Rate specifically for new data center load. The Commission has not yet issued an order in the case.

Q. Did you testify in U-21859 on data center cost allocation and rate design?

A. Yes. I testified that the riskiness and magnitude of infrastructure investment associated with potential new data centers taking service in Consumers' territory necessitates re-evaluating the ways that Consumers would track and allocate the costs of its investments for data centers.³⁸

³⁷ \$0.45 million plant and \$0.19 million O&M expense. See Davis Direct, p.15.

³⁸ Direct Testimony of Caroline Palmer. Case No. U-21859. June 12, 2025. Section III.

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I recommended that, instead of allocating data-center-related generation costs through existing cost of service methods, Consumers directly assign data centers such costs. I recommended that Consumers identify incremental generation costs by conducting integrated resource plan (“IRP”) modeling with and without data center load.³⁹ I further recommended that Consumers directly assign all dedicated distribution facility costs to data centers without CIAC offsets.⁴⁰

Q. How did Consumers respond to your data center cost allocation and rate design testimony in U-21859?

A. Consumers stated that the “issue of direct assigning costs to data center customers [wa]s beyond the Company’s proposal” in U-21859. Rather, Consumers argued, any “determinations on cost assignment and cost allocation should be handled in the context of an electric general rate case.” The Company stated that it “intends to file a future rate proposal which will address cost allocation and rate design issues for new data center customers.”⁴¹

Q. When does Consumers intend to address cost allocation and rate design issues for new data center customers?

A. During the U-21859 hearing, Witness Connolly testified that the Company had not made a decision regarding when it might make proposals to modify existing methods of cost allocation relative to data centers. Witness Connolly said that typically, the customer class

³⁹ *Id.* at Section Va.

⁴⁰ *Id.* at Section Vb.

⁴¹ Rebuttal Testimony of Laura M. Connolly, Case No. U-21859, 3 Tr 100.

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1 or expected customer class would have load in the test year and expected customers to pay
2 the allocated costs.⁴²

3 **Q. Has Consumers announced new data center load growth in its service territory since**
4 **filing U-21859 and this rate case?**

5 A. Yes. In its August 1, 2025 news release for its 2025 Second Quarter Results & Outlook,
6 Consumers announced that it had reached an agreement with a new data center, which is
7 expected to add up to 1 gigawatt of load growth in its service territory.⁴³

8 **Q. In light of Consumers' substantial new data center load agreement, do you**
9 **recommend that the Commission and Company prepare now for data center cost**
10 **allocation in future rate cases?**

11 A. Yes. Given the significant new data center load that Consumers has agreed to serve, it is
12 quite possible that there could be data center load in Consumers' next rate case test year.
13 Also, Consumers may soon begin to incur costs to serve the new customer – and any other
14 customers that reach agreements with the Company. Proactive assessment of costs and cost
15 causation is essential to equip the Company, Commission, and other parties with the
16 information necessary to properly evaluate the impacts of unprecedented new load growth
17 and to assign the associated costs justly and reasonably.

⁴² Cross Examination of Laura M. Connolly, Case No. U-21859, 3 Tr 206-208.

⁴³ MNSC Hearing Exhibits Ex MEC-46 in U-21859, source: CMS-Energy-2Q25-Earnings-Release-Combined-Final.

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Q. How do you recommend preparing now for future data center cost allocation decisions?

A. First, I recommend that the Commission order Consumers to demonstrate in its next rate case that its proposed cost allocation methods satisfy the legislative requirement that residential customers will not subsidize the costs incurred to provide electric service to a data center.

Second, I recommend that the Commission order Consumers to conduct sensitivity modeling runs in its next IRP with and without data center load of magnitudes that reasonably reflect Consumers' expected data center load at the time, and disclose the difference in revenue requirements and resource portfolios. I discuss each sequentially.

Q. Why do you recommend that Consumers demonstrate that its cost allocation approaches will not cause residential customers to subsidize the costs incurred to provide electric service to the facility?

A. Under MCL 205.54ee(10)(e)(x)(c), an enterprise data center "will not take electric service under" "[a] rate that causes residential customers to subsidize the costs incurred to provide electric service to the facility." In Case No. U-21859, Consumers did not analytically engage with this requirement, such as by attempting to quantify the costs associated with new data center customers and assessing quantitatively whether the new customers would cover those costs. Instead, Consumers focused mainly on the "risk for stranded assets with respect to data center customers,"⁴⁴ not on the risk of cost shifting even if data center load materializes as expected. Consumers concluded without evidence that "Approval of the

⁴⁴ Consumers Energy Application in U-21859, February 7, 2025, p. 2.

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1 proposed amendments will not increase any existing rates or the cost of service to other
2 customers.”⁴⁵

3 Since Consumers has argued that a rate case is the appropriate forum to address
4 data center cost assignment, a rate case must therefore be at least one of the places that the
5 Company demonstrates that residential customers do not subsidize the costs incurred to
6 provide electric service to data centers. Consumers should quantitatively address this
7 requirement in its next rate case.

8 **Q. Have other utilities addressed similar legislative requirements?**

9 A. Yes. Ameren Missouri acknowledged that state law requires that large load customers’
10 rates reflect the costs incurred to serve them and prevent unjust or unreasonable costs to
11 other customer classes; Ameren in turn attempted to quantitatively demonstrate that its
12 proposed data center rates would not cause unjust or unreasonable costs to other customer
13 classes.⁴⁶ While Ameren’s analysis was flawed and unsatisfactory, utilities, parties, and
14 Commissions must nonetheless engage with such legislative requirements.

15 **Q. Why do you recommend that Consumers model its next IRP with and without data**
16 **center load?**

17 A. The results of such analysis will help the Commission assess whether data centers pay their
18 costs without subsidization from residential customers. Parties in U-21859 asked the
19 Company several times to share estimates of the incremental generation costs associated
20 with data center load, but Consumers stated that load growth studies and decisions

⁴⁵ *Id.* at 6.

⁴⁶ Direct Testimony of Steven M. Wills, Missouri Public Service Commission File No. ET-2025-0184, May 14, 2025. Section V.

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1 regarding the addition of new peak load and required generation supply would be included
2 in the Company's 2026 IRP. However, the Company plans to determine the required
3 generation investment for the entirety of its service territory, not specifically for data center
4 load.⁴⁷ This is a missed – and critical – opportunity to estimate the incremental generation
5 costs of data center load. The additional information from with-and-without IRP modeling
6 may be one of the best and only ways to evaluate the impacts of unprecedented data center
7 load on Consumers' generation costs.

8 **Q. Have other jurisdictions conducted IRP runs with and without data center load?**

9 A. Yes. I am aware that at least Dominion Virginia⁴⁸ and Ameren Missouri have done so.
10 Ameren Missouri, for example, evaluated resource plans based on seven different
11 prospective large load cases and compared each to a baseline resource plan which included
12 no incremental large load demand.⁴⁹

⁴⁷ Direct Testimony of Caroline Palmer, Case No. U-21859, June 12, 2025, pp. 26-27.

⁴⁸ Virginia Electric and Power Company's SCC Directed 2024 IRP Supplement. November 15, 2024, Case No. PUR-2024-00184, Virginia Electric and Power Company's 2024 Integrated Resource Plan filing pursuant to Va. Code § 56-597 et seq.

⁴⁹ Direct Testimony of Matt Michels, Missouri Public Service Commission File No. ET-2025-0184, May 14, 2025. p. 8.

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1 **IV. RATE DESIGN**

2 ***Large Economic Development Rate (“LED R”)***

3 *1. The Commission Should Reject Consumers’ Proposed LED R Facilities Allowance*

4 **Q. Describe Consumers’ LED R facilities allowance proposal.**

5 A. Consumers proposes to include a facilities allowance for Rate LED to “better align with
6 other cost-based large customer rate options in Michigan,”⁵⁰ because potential customers
7 have apparently inquired about the availability of a facilities allowance such as that offered
8 under DTE Electric Company’s Rate D13. The Company would calculate the allowance as
9 the NPV of five years of a customer’s expected system contribution revenue and
10 distribution revenue.⁵¹ The Company would then reduce the LED R customer’s incremental
11 distribution charge by the calculated facilities allowance.

12 **Q. Describe the incremental distribution costs that the facilities allowance would offset.**

13 A. The incremental distribution charge collects costs related to dedicated substation,
14 transformers, wires, and metering needed to serve the specific customer’s site.⁵² In other
15 words, the incremental distribution costs that are incurred strictly to provide service to the
16 LED R customer.

⁵⁰ Direct Testimony of Laura M. Connolly, p.11.

⁵¹ Exhibit MEC-19, Consumers Response to U21870-MNSC-CE-0253, Att. 1.

⁵² Exhibit MEC-19, Consumers Response to U21870-MNSC-CE-0253(c); MEC-20, Consumers Response to U21870-MNSC-CE-0255(c).

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1 **Q. What are your concerns with the LEDR facilities allowance?**

2 A. I am concerned that reducing an LEDR customer's incremental distribution charge by the
3 facilities allowance would increase costs for other customers. When the Commission
4 originally approved Rate LED, it did so based on the determination that the rate would not
5 result in higher costs or rates for other customers, and it stated that increasing costs for
6 other customers contradicts Michigan law.⁵³ Thus, it is imperative that any facilities
7 allowance not increase other customers' costs. I am also concerned by Consumers'
8 proposal to retroactively apply the facilities allowance and the lack of cost true-up for
9 overestimated facilities allowances. I address each concern sequentially.

10 **Q. How could Consumers' proposed LEDR facilities allowance increase costs for other**
11 **customers?**

12 A. Consumers' LEDR facilities allowance could increase costs for other customers if the
13 revenues paid by the LEDR customer do not fully offset the incremental costs of serving
14 that customer. The incremental distribution costs of serving an LEDR customer consist of:

15 1) The customer's dedicated infrastructure (e.g., metering, service drop,
16 transformer, etc); and

17 2) The marginal cost associated with higher demand on the rest of the shared
18 distribution system⁵⁴ (expressed as the marginal distribution cost in \$/kW).

19 The cost of (1) is typically recovered through the customer's "incremental" distribution
20 charge. However, the facilities allowance would reduce that charge. Thus, to ensure that

⁵³ Michigan Public Service Commission, "MPSC approves DTE Electric, Consumers Energy special rates to help attract, retain advanced manufacturing." December 22, 2021, <https://www.michigan.gov/mpsc/commission/news-releases/2021/12/22/mpsc-approves-dte-electric-consumers-energy-special-rates>. Accessed, September 25, 2025.

⁵⁴ Including shared lines, transformers, substations, etc.

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1 there is no cost shifting to other customers, Consumers must demonstrate that the customer
2 revenues included in the facilities allowance, including standard distribution rates paid by
3 LEDR customers, cover not only their portion of the customer's facilities allowance, but
4 also the marginal cost associated with accommodating the customer's load on the rest of
5 the distribution system (2). While prior cases have rightfully narrowed the revenues that
6 could be included in any LEDR facilities allowance for this reason, the inclusion of Rate
7 LED customers' distribution revenues in the facilities allowance likely still uses Rate LED
8 customers' marginal costs to pay for their facilities costs.

9 Currently, Consumers can not ensure that the LEDR distribution rates cover the full
10 incremental cost associated with serving a LEDR customer (including any facilities
11 allowance) because it has not calculated its marginal distribution cost (2). When asked to
12 identify its marginal cost of distribution capacity in discovery, Consumers said that the
13 "Company has not analyzed this information" and has only reviewed the marginal cost of
14 production capacity.⁵⁵

15 **Q. Do you recommend the Commission reject the facilities allowance?**

16 A. Yes. The Commission can only conclude that the facilities allowance will not shift LEDR
17 costs to other customers when Consumers can demonstrate that the customer will pay all
18 of its marginal distribution costs despite using five years of distribution revenues to pay for
19 its incremental, dedicated facilities costs, rather than paying for other distribution costs
20 during that time. Given that Consumers has not demonstrated this, I recommend that the
21 Commission reject the facilities allowance.

⁵⁵ Exhibit MEC-21, Consumers Response to U21870-MNSC-CE-0256(g).

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1 **Q. Does Consumers propose to apply the facilities allowance retroactively to current**
2 **LEDR customers?**

3 A. Yes. “The Company believes the facilities allowance should apply to existing Rate LED
4 customers if approved,” by calculating their facilities allowance, applying it to the existing
5 customer’s incremental facilities costs, and recalculating their incremental facilities
6 charge.⁵⁶

7 **Q. Is it appropriate to apply the facilities allowance to existing LEDR customers?**

8 A. No. The Commission approved Rate LED to attract new load – and the associated
9 investment and jobs – to the state. The existing LEDR rate has already succeeded in
10 attracting existing LEDR customers to the state without a facilities allowance. The
11 Company has not demonstrated that the facilities allowance is necessary to retain these
12 existing customers. Instead, these customers would likely be free-riders—receiving a
13 discount despite it playing no part in their decision to locate in Consumers’ territory. This
14 would serve to unreasonably increase costs for other customers.

⁵⁶ Exhibit MEC-22, Consumers Response to U21870-MNSC-CE-0257(d).

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Q. How much would it cost to provide the facilities allowance retroactively for existing customers?

A. Using Consumers' test year forecast for Rate LED capacity and energy,⁵⁷ the magnitude of Consumers' proposed facilities allowance for existing customers would be [REDACTED] million, which Consumers would no longer collect in Rate LED revenue.⁵⁸

Q. What do you recommend regarding providing the facilities allowance to existing customers?

A. If the Commission approves a facilities allowance, it should reject Consumers' proposal to provide the facilities allowance retroactively to existing customers. Not only could this credit reduce LEDR customers' revenues below marginal costs, but surrendering these revenues is completely unnecessary given that existing LEDR customers have already made the decision to site their operations in Consumers' service territory.

Q. Does Consumers propose to true up the facilities allowance?

A. No, it does not appear that Consumers intends to true up the facilities allowance if the Company initially overestimated an LEDR customer's expected annual revenues when calculating the facilities allowance. In such case, the LEDR customer would receive a higher facilities allowance than provided for in Consumers' proposal, at a cost to other customers.

Q. If the Commission approves a facilities allowance, do you recommend that Consumers true up the facilities allowance if it overestimated a customer's revenues?

⁵⁷ Exhibit A-70 (LMC-9) CONF.

⁵⁸ Calculated using the sample calculation provided in U21870-MNSC-CE-0253_Connolly_ATT_1, which calculates the NPV of 5 years' worth of system contribution charges and distribution revenues at current rates.

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1 A. Yes. After Consumers has collected five years of revenue, the Company should reconcile
2 any overestimated revenue upon which it originally based the facilities allowance, by
3 recalculating the customer's incremental distribution charges based on the lower facilities
4 allowance due to the lower revenue received.

5 *2. Consumers Should Increase the LEDR System Contribution Charge*

6 **Q. What costs does the LEDR system contribution charge collect?**

7 A. The system contribution charge, approved in Case No. U-21160 as part of Rate LED, was
8 intended to "ensure the Company's existing customers also benefit during the term of the
9 contract by having the Rate LED customer contribute to the utility's fixed power supply
10 costs."⁵⁹ It is designed to cover a portion of the embedded costs of capacity.⁶⁰ Specifically,
11 the charge was set based on 1% of the Rate GPD embedded capacity costs approved in
12 2020 in U-20697 and seemingly has not been updated since.⁶¹

13 **Q. Why did Consumers set the system contribution charge at 1% of the Rate GPD**
14 **embedded capacity costs?**

15 A. Consumers seemingly did not base the charge on any assessment of Rate LEDR's
16 embedded cost or other analytical justification. Per Witness Miller's cross-examination in
17 U-21224, it seems that Consumers considered this remarkably small charge to be the most
18 it could ask Rate LED to pay and keep the rate competitive.⁶²

⁵⁹ U-21160 Consumers Energy Application. U-21160. November 4, 2021.

⁶⁰ Exhibit MEC-21, Consumers Response to U21870-MNSC-CE-0256(f).

⁶¹ Exhibit MEC-20, Consumers Response to U21870-MNSC-CE-0255(d).

⁶² Cross examination of Hubert Miller in Case No. U-21224, 3 Tr 635-637.

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1 **Q. Do you recommend that Consumers raise the system contribution charge?**

2 A. Yes. Consumers has not presented a cost basis for setting its system contribution charge at
3 1% of the Rate GPD embedded capacity costs. I recommend that the Company raise the
4 charge in order to contribute more meaningfully to embedded system costs.

5 3. *Consumers Should Shorten the LEDR Discount Period*

6 **Q. What is the Rate LED contract term?**

7 A. The minimum term is 15 years and the maximum contract term shall not exceed 20 years
8 from the initial service date.⁶³ LEDR customers receive the discount throughout the
9 contract term.

10 **Q. Is this discount period long compared to other economic development rates?**

11 A. Yes. A number of jurisdictions offer discount rates for just five years, including LGE and
12 KU in Kentucky,⁶⁴ Dominion in Virginia,⁶⁵ Evergy in Missouri and Kansas,⁶⁶ Florida
13 Power and Light,⁶⁷ and Interstate Power and Light in Iowa.⁶⁸ For Dominion in South

⁶³ Consumers' Electric Rate Book. Accessed at <https://www.consumersenergy.com/-/media/CE/Documents/rates/electric-rate-book.pdf>.

⁶⁴ LGE KU, *Economic Development Rider*, <https://lge-ku.com/economic-development/rider> (accessed September 25, 2025).

⁶⁵ Dominion Energy, *Economic Development Incentives & Special Rates*, <https://www.dominionenergy.com/-/media/content/economic-development/virginia/pdfs/economic-development-incentives-special-rates-va.pdf>. (accessed September 25, 2025).

⁶⁶ Evergy, *Economic Development Rider Incentive*, <https://www.evergyed.com/site-selection/edr-rider-incentive/> (accessed September 25, 2025).

⁶⁷ Florida Power & Light Company, *Economic Development Rider-EDR*, accessed at: <https://www.poweringflorida.com/content/dam/poweringflorida/us/en/pdf/FPL%20Combined%20Economic%20Development%20Programs.pdf>

⁶⁸ Interstate Power and Light Company, *Rider ECON- Economic Development Rate*, accessed at: https://www.alliantenergy.com/-/media/alliant/documents/accountandbilling/ratesandtariffs/iowaelectricrates/ridereconomicdevelopmentrate.pdf?sc_lang=en&hash=6404DD5B0C297A984510D49BEA282777

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1 Carolina, the credit applies for five years, but customers must remain on the system for 10
2 years (i.e., a contract term of 10 years). If the customer departs before 10 years, it is liable
3 for a proportion of the credits provided.⁶⁹ Indiana Michigan Power provides an economic
4 discount rate to Indiana customers for seven years.⁷⁰

5 **Q. Do you recommend that Consumers shorten the length of its Rate LED discount?**

6 A. Yes. I recommend that Consumers offer rate LED for a maximum of seven years.
7 Consumers has not justified why it should provide substantial rate discounts for such a long
8 time. Until Consumers provides such justification, Rate LED should only provide
9 discounts for a shorter period of time.

10 **Q. Does that complete your testimony?**

11 A. Yes.

⁶⁹ Dominion Energy South Carolina, INC, *Rider to Retail Rates Economic Development Rider*, accessed at: <https://cdn-dominionenergy-prd-001.azureedge.net/-/media/content/rates-and-tariffs/pdfs/south-carolina/electric/riders/economic-development-rider.pdf?rev=2c3654bb1938410795b9d5925dcfb686&hash=B6577F4D669D09E2822E87913BADA281>

⁷⁰ Indiana Michigan Power, *Indiana Economic Development Rider 2*, accessed at: <https://docs.aep.com/docs/economic-development/IN-EDR-2023-App.pdf>

1 MR. BZDOK: Thank you. At this time on behalf
2 of Citizens Utility Board of Michigan, I would move to
3 bind it to the record the direct testimony of Matthew
4 Bandyk, which consists of a cover page, a table of
5 contents, and 38 pages of questions and answers. And I
6 would move for the admission into evidence Exhibits CUB-1
7 through CUB-10.

8 JUDGE THOITS: Are there any objections to the
9 admissions of this testimony or these exhibits?

10 Hearing none. The direct testimony of Matthew
11 Bandyk is bound into the record, and Exhibits CUB-1
12 through CUB-10 are admitted.

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STATE OF MICHIGAN
BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the Application of
CONSUMERS ENERGY COMPANY for U-21870
authority to increase its rates for the generation
and distribution of electricity and for other
relief.

**DIRECT TESTIMONY OF
MATTHEW BANDYK**

**ON BEHALF OF
CITIZENS UTILITY BOARD OF MICHIGAN**

September 29, 2025

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**DIRECT TESTIMONY OF MATTHEW BANDYK ON BEHALF OF CUB
CASE NO. U-21870**

I. INTRODUCTION AND PURPOSE OF TESTIMONY

Q Please state your name and occupation.

AMy name is Matthew Bandyk. I am a Principal Associate at Synapse Energy Economics Inc., located at 485 Massachusetts Ave, Suite 3, Cambridge, MA 02139.

Q Please describe Synapse Energy Economics.

ASynapse is a research and consulting firm specializing in energy and environmental issues, including electric generation, transmission and distribution system reliability, ratemaking and rate design, electric industry restructuring and market power, electricity market prices, stranded costs, efficiency, renewable energy, environmental quality, and nuclear power.

Synapse's clients include state consumer advocates, public utilities commission staff, attorneys general, environmental organizations, federal government agencies, and utilities.

Q Please summarize your work experience and educational background.

AAt Synapse, I focus on cost of capital testimony. 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-1.

In 2025 I successfully completed a comprehensive written exam to be awarded the Certified Rate of Return Analyst (CRRA) designation from the Society of Utility and Regulatory Financial Analysts (SURFA).

**DIRECT TESTIMONY OF MATTHEW BANDYK ON BEHALF OF CUB
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1 **Q Have you previously testified before state regulatory commissions?**

2 **A Yes. I have previously testified before the Michigan Public Service Commission in the**
3 following cases:

- 4 • Case No. U-21860 (DTE Electric rate case);
- 5 • Case No. U-21806 (Consumers Energy gas rate case);
- 6 • Case No. U-21585 (Consumers Energy electric rate case);
- 7 • Case No. U-21534 (DTE Electric rate case);
- 8 • Case No. U-21555 (UPPCO rate case);
- 9 • Case No. U-21540 (Michigan Gas Utilities rate case);
- 10 • Case No. U-21490 (Consumers Energy gas rate case);
- 11 • Case No. U-21389 (Consumers Energy electric rate case);
- 12 • Case No. U-21048 (Consumers Energy 2022 PSCR Plan case); and
- 13 • Case No. U-21291 (DTE Energy gas rate case).

14 I have also testified before the California Public Utilities Commission in:

- 15 • Case No. A.2503013 (San Diego Gas & Electric Cost of Capital for Test Year 2026)

16 **Q On whose behalf are you testifying in this case?**

17 **A I am testifying on behalf of the Citizens Utility Board of Michigan.**

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

19 **A In this proceeding, I will give my expert opinion as to an appropriate return on equity**
20 (ROE), capital structure, and overall rate of return for Consumers Energy (the Company).

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1 **Q How is your testimony structured?**

2 **A In Part II, I summarize my findings and recommendations. In Part III, I discuss the**
3 overarching principles of a fair cost of capital that guide my testimony. In Part IV, I discuss
4 the methodology and results of the financial models that I use to estimate the Company's
5 ROE. Finally, in Part V, I discuss my recommendations for a fair capital structure for the
6 utility.

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

8 **A Yes, I am sponsoring the following exhibits:**

9 CUB-1: Resume of Matthew Bandyk
10 CUB-2: Proposed Capital Structure
11 CUB-3: Equity Risk Premium
12 CUB-4: Beta
13 CUB-5: CAPM Analysis
14 CUB-6: Long-Term Growth Rate Sources
15 CUB-7: DCF (with Earnings Growth Rates)
16 CUB-8: DCF (with Dividend Growth Rates)
17 CUB-9: Interest Coverage Ratios
18 CUB-10: CAPM for U.S. Stock Market

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Q Have you in good faith attempted to locate the forecasted return on equity for the United States stock market and the reported average ROE authorized for regulated utilities in the United States for the last two or more years in accordance with the amended scheduling memorandum in this case?

A Yes. I have in good faith attempted to locate the requested information in public resources or resources available to me. I provide my calculation of the forecasted return on equity for the U.S. stock market in the section of my testimony about the CAPM. To my knowledge, the primary source for average authorized ROE is a report published by Regulatory Research Associates (RRA), which is accessible only through a costly subscription that I do not have. I did, however, locate an article published by the Rocky Mountain Institute reporting that the average authorized ROE for 2024 was 9.7%.

II. FINDINGS AND RECOMMENDATIONS

Q Please summarize your findings.

A My primary findings are:

1. Company witness Ann Bulkley has proposed an excessive return on equity of 10.25%, well above the current authorized ROE (9.9%), the 2024 national average for authorized ROEs (9.7%), and the cost of equity of the U.S. stock market as calculated by me later in my testimony (9.02%). This proposed ROE would increase costs to ratepayers by approximately \$70 million annually relative to a market-based ROE of 9.22%.
2. The Company's calculation of the Equity Risk Premium is flawed, as it assumes unsustainably high long-term growth rates.

**DIRECT TESTIMONY OF MATTHEW BANDYK ON BEHALF OF CUB
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1 3. The Company inappropriately uses only short-term earnings projections as the
2 perpetual growth rate in the Discounted Cash Flow model.

3 4. The Company inappropriately uses adjusted betas in its Capital Asset Pricing
4 Model analysis that do not account for regulated utilities' lower systematic risk.

5 5. The Company uses the circular Risk Premium method, which anchors the risk
6 premium to previously authorized ROEs that are themselves excessive, and has
7 been rejected by FERC for being redundant and circular.

8 6. The Company uses unsubstantiated risk adders that do not reflect rating agencies'
9 views, as shown by Consumers Energy's credit ratings, which are in line with or
10 better than those for the proxy group.

11 7. The Company's proposed equity ratio is also excessive and would not minimize
12 costs to ratepayers.

13 **Q Please summarize your recommendations.**

14 **A Based on my findings, I offer the following recommendations:**

15 1. The Commission should authorize an ROE of 9.22%, which represents the
16 midpoint between 8.63%, as calculated using objective financial methods that
17 correct for the flaws in the Company's analysis, and the Company's current
18 authorized ROE of 9.9% and would serve to more gradually reduce the Company's
19 ROE.

20 2. The Commission should reject the use of the Risk Premium Model by Ms. Bulkley.
21 It is circular and lacks support in Commission precedent, and its inclusion only
22 serves to inflate ROE results.

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1 3. The Commission should reject any risk adders advanced by Ms. Bulkley, as they
2 are unsupported by objective financial evidence.

3 4. The Commission should adopt a capital structure for the Company of 50% equity
4 and 50% debt, as it ensures financing costs are minimized while preserving the
5 Company's ability to maintain strong credit metrics.

6 **III. COST OF CAPITAL - PRINCIPLES**

7 **Q Please explain the concept of cost of capital and its significance.**

8 **A**The cost of capital is the return demanded by investors on the capital they supply to the
9 Company.¹ It is the weighted average of the costs of the various classes of capital supplied
10 by investors — in this case, debt and equity. The cost of debt and cost of equity are each
11 weighted by the respective amounts of debt and equity in the Company's total capital
12 structure, so the ratio of equity to debt is another important component of the cost of capital.
13 The cost of debt can be relatively easily observed through the interest rates lenders demand
14 on debt issued by the Company. The cost of equity, however, is the product of market
15 expectations that can only be estimated by examining a number of factors.

16 Estimating the cost of equity for a regulated utility must be done carefully so as to arrive
17 at a return that ensures rates that are “just and reasonable,” a principle elaborated on in the
18 landmark U.S. Supreme Court cases that set the legal standards governing public utility
19 regulation, *Bluefield Water Works & Improvement Co. v. Public Service Commission of*
20 *West Virginia* and *Federal Power Commission v. Hope Natural Gas Co.*

¹ Roger A. Morin, PhD. Modern Regulatory Finance. PUR Books, 2021, p. 27.

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1 For example, in *Hope*, the Court found that the “just and reasonable” standard implies that
2 “the return to the equity owner should be commensurate with returns on investments in
3 other enterprises having corresponding risks.² That return, moreover, should be sufficient
4 to assure confidence in the financial integrity of the enterprise, so as to maintain its credit
5 and to attract capital.”³

6 But the Court was also clear that the determination of what return is “sufficient” in that
7 regard must also involve a consideration of the interests of the company’s
8 customers.⁴ Indeed, just as a return for a utility that is set below the amount
9 “commensurate with returns on investments in other enterprises having corresponding
10 risks” causes the utility to lose wealth relative to what it should earn with a more
11 appropriate return, a return that is set above this amount will cause the utility’s customers
12 to be overcharged and lose wealth relative to what they would be charged with a lower and
13 more appropriate return. In this latter case, that wealth is instead transferred from
14 customers to the utility holding company’s shareholders.

15 **Q What methods may be employed to determine the cost of capital?**

16 **A** In *Hope*, the Supreme Court explained that it is the result reached, not the method
17 employed, which is controlling, and that result should be a rate that people would
18 reasonably consider to be commensurate with the risk of the investment.⁵ In practice,

² *Fed Power Com v Hope Natural Gas Co*, 320 US 591 (1944).

³ *Id.* at 603.

⁴ *Id.*

⁵ *Id.* at 602.

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1 reaching that result involves using methods that are widely accepted in the financial
2 community to estimate investor perceptions of risk. I rely on these methods in my
3 testimony to estimate the Company's cost of equity, which informs my recommendation
4 for the authorized ROE.

5 **Q How have public regulatory commissions historically fared at estimating returns on**
6 **equity for utilities that are commensurate with risk?**

7 **A** There is strong evidence from multiple observers and peer-reviewed academic research
8 that public regulatory commissions have tended to set electric utility ROEs above the
9 "market-based ROE," as I describe more below.

10 **Q What is the "market-based ROE"?**

11 **A** The "market-based ROE" is the ROE that economists would arrive at using widely
12 accepted methods for estimating cost of equity. These methods gauge how the market rates
13 the risk of a utility investment to determine the return required. The trend in commissions
14 approving ROEs that exceed a market-based ROE has resulted in a transfer of wealth from
15 ratepayers to shareholders and resulted in a skewed average authorized ROE.

16 **Q Is there any empirical evidence supporting your claim that approved ROEs tend to**
17 **exceed the market-based ROE?**

18 **A** Yes. Academics have observed a growing premium of regulatory commission-awarded
19 ROEs over the rate of return on long-term U.S. Treasury bonds (the risk-free rate), and
20 research has found that this premium cannot statistically be explained by financial

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fundamentals, such as a change in the equity or debt risk of the utilities in question.⁶ In other words, statistical evidence shows that the utility ROEs are increasingly being set above the actual cost of equity. This can be observed in the graph below, which shows how the authorized ROE premium over the 10-year treasury yield has grown from approximately 3 percent in the mid-1980s to nearly 8 percent in recent years.⁷

Figure 1. Annual average authorized return on equity vs. Treasury yield and investment-grade corporate bond rates

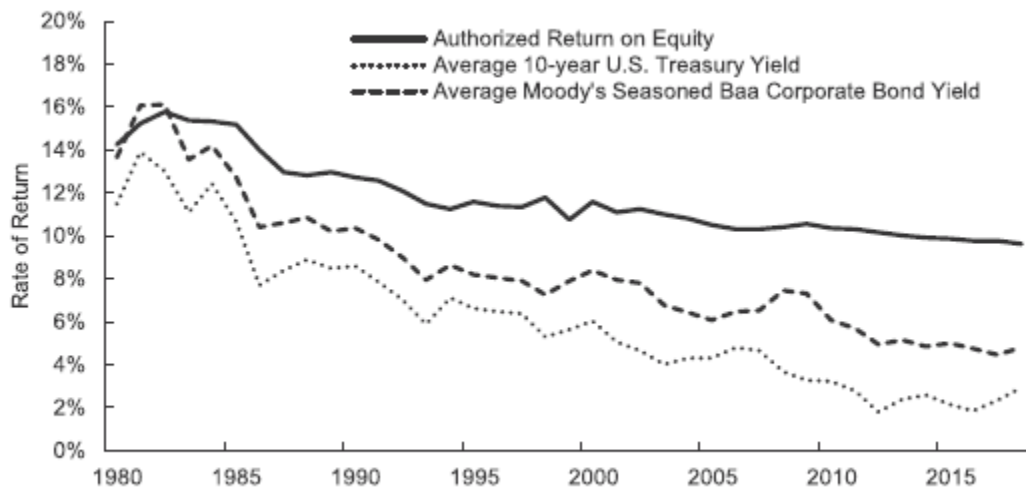


Fig. 4. Annual average authorized return on equity vs. U.S. Treasury and Investment grade corporate bond rates.

The growing premium unreasonably increases costs to consumers because it ensures that utilities collect a greater return from consumers than would be justified by a market-based

⁶ “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>

⁷ *Id.* at 5.

⁸ *Id.*

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1 ROE and strengthens utilities' incentive to make more capital investments than necessary.⁹

2 A 2023 paper published by the Energy Institute at the University of California Berkeley's
3 Haas School of Business found that rates of return for electric and gas utilities being set
4 above a market-based return costs U.S. consumers around \$7 billion per year.¹⁰

5 Experts such as utility attorney Steve Huntoon have also examined the record of authorized
6 ROEs and found that regulators tend to set ROEs above the return for investments that are
7 riskier than utilities.¹¹

8 A higher return implies higher risk, so approving ROEs that are higher than market returns
9 would imply that regulated utilities are riskier investments than the market as a whole. But
10 they are not. Regulated utility returns tend to be less risky than the market as a whole,
11 indicating that regulatory decisions are not in line with the economic reality that lower risk
12 means lower return.

⁹ When a utility's rate of return is greater than the cost of borrowing, utilities have a financial incentive to maximize their capital expenditures in order to increase rate base and thereby increase profits. This is often referred to as the Averch-Johnson effect. See: Averch, Harvey, and Leland L. Johnson. "Behavior of the Firm Under Regulatory Constraint." *The American Economic Review* 52, no. 5 (1962): 1052–69. Available at: <http://www.jstor.org/stable/1812181>.

¹⁰ 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>.

¹¹ 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>.

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1 **Q What evidence do you have that utilities are less risky than the market as a whole?**

2 **A** Beta is a measurement of the sensitivity of a stock's returns relative to those of the market
3 as a whole. Utility holding company betas tend to be less than one, meaning that those
4 stocks are less sensitive to changes in overall market returns.

5 **Q** **If regulated utilities are less risky than the market, then why have regulated utilities**
6 **historically been awarded ROEs above market returns?**

7 **A** The remaining explanation is that public regulatory commissions have tended to accept
8 estimates for ROE that are above fair, market-based ROE estimates.

9 **Q** **What factors have contributed to commissions approving ROEs that exceed the**
10 **market-based ROE?**

11 **A** Determining the market-based ROE is inherently an exercise in estimation, which
12 invariably includes some degree of subjectivity. Subjective factors can influence any
13 human decision-making process, including the decisions of public utility regulatory
14 commissions, leading to unintended results. These factors include the influence of utilities
15 in the regulatory process. Utilities often have more resources to advocate for higher ROEs
16 and amplify their position more effectively than opposing groups, regardless of whether
17 their arguments are stronger. This imbalance can skew regulatory outcomes and undermine
18 the public interest.

19 **Q** **What ROE is Consumers Energy proposing in this case?**

20 **A** Consumers Energy is proposing a 10.25% ROE, a significant increase from its current ROE
21 of 9.9%.

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1 **Q How do these current and proposed ROEs compare to the average ROE authorized**
2 **by regulators around the country?**

3 **A Both the 9.9% current ROE and the 10.25% proposed ROE are significantly higher than**
4 **the 9.7% average ROE authorized by state regulatory commissions in 2024.¹²**

5 **Q How do you view the Company's proposed ROE in light of the aforementioned**
6 **evidence about ROEs generally being set too high?**

7 **A The fact that a) there is evidence that nationally utility ROEs are set too high and b) the**
8 **Company's proposed ROE is higher than average strongly suggests that Consumers**
9 **Energy's proposed ROE is excessive. As I will explain, Ms. Bulkley's application of**
10 **financial models to determine her recommended ROE makes several errors that inflate the**
11 **ultimate ROE range.**

12 **Q Ms. Bulkley claims that "an authorized ROE significantly below authorized ROEs**
13 **for other utilities can inhibit the utility's ability to attract capital for investment."¹³**
14 **Do you agree?**

15 **A No. Ms. Bulkley is conflating the cost of equity with the authorized ROE of other utilities.**
16 **The cost of equity is a theoretical concept for the opportunity cost faced by investors when**
17 **considering a specific investment. An ROE that is set *below the cost of equity* could be an**
18 **impediment to the Company's ability to attract financing. But ROEs authorized for peer**
19 **utilities are not the same as the actual cost of equity. ROE is an accounting concept for the**

¹² Daniel, Foelske, and Kihm, "Rebalancing 'Return on Equity' to Accelerate an Affordable Clean Energy Future," RMI, Feb. 21, 2025, <https://rmi.org/rebalancing-return-on-equity-to-accelerate-an-affordable-clean-energy-future/>.

¹³ Direct Testimony of Ann E. Bulkley, p. 7.

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1 return generated by an equity investment. The cost of equity is what we are trying to
2 estimate through financial models that gauge the opportunity cost. As explained above,
3 regulatory commissions routinely set authorized ROEs well above the actual cost of equity
4 for utilities. Thus, we cannot look to other jurisdictions to determine the opportunity cost
5 for investors. An ROE can be set below the national average for authorized ROEs and still
6 be above the cost of equity – meaning that ROE still provides a return to investors that is
7 more than adequate to attract the required capital.

8 **Q Would Consumers Energy customers pay for an excessive return if the Commission**
9 **approves Ms. Bulkley's proposed ROE in this case?**

10 **A** Yes, customers would pay approximately \$71 million per year more than necessary if the
11 Commission adopts Ms. Bulkey's inflated ROE proposal. The ROE is a component of the
12 overall rate of return along with the cost of debt. If the Commission were to approve
13 Consumers Energy's request for a rate increase without changes, the Company would
14 collect about \$975.36 million from customers for a return on its rate base, based on an
15 overall rate of return of 6.35%¹⁴ and a total jurisdictional rate base of \$15.36 billion.¹⁵ If
16 the ROE were instead the market-based ROE of 9.22% that I am recommending in this
17 case, along with my proposed 50/50 debt-equity ratio, the overall rate of return would fall
18 to 5.89%¹⁶, and so the amount collected would fall from \$975.36 million to \$904.70
19 million, resulting in savings to customers of about \$70.65 million per year.

¹⁴ Exhibit A-14, Sched. D-1.

¹⁵ Exhibit A-12, Sched. B-1.

¹⁶ See Exhibit CUB-2, Proposed Capital Structure.

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1 **IV. COST OF CAPITAL – METHODS**

2 *Summary*

3 **Q What quantitative methods did you use to estimate the utility's ROE?**

4 **A**Arriving at an ROE commensurate with risk requires the use of methods that are widely
5 accepted in the financial community to estimate investor perceptions of risk. My ROE
6 estimate is based on the Capital Asset Pricing Model (CAPM) and the Discounted Cash
7 Flow (DCF) methods, which are widely accepted methods for calculating ROE. These are
8 also two of the methods used by Ms. Bulkley to develop her recommended ROE. I did not,
9 however, use two of the methods she used, for reasons I will explain. These two are the
10 Empirical Capital Asset Pricing Model (ECAPM) and the Risk Premium analysis.

11 **Q Did you use a different proxy group than Ms. Bulkley?**

12 **A**No. I used the same proxy group as Ms. Bulkley. Therefore, the differences between our
13 results are due to differences in how we employ financial models, rather than differences
14 in the companies included in the models.

15 **Q What are the results of your analysis?**

16 **A**The results of my DCF and CAPM analyses, which inform my resulting recommendation
17 for the utility's ROE in this case, are shown in Figure 2 below:

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Fig. 2

DCF	
EPS growth rates	9.65%
DPS growth rates	8.26%
Average	8.96%
CAPM	
with Damodaran ERP and Value Line Beta	7.97%
with Damodaran ERP and Bloomberg Beta	6.96%
with Kroll ERP and Value Line Beta	9.37%
with Kroll ERP and Bloomberg Beta	8.13%
Average	8.11%
Average of Averages	8.53%

Q What is your ROE recommendation?

A I recommend an ROE for Consumers Energy of 9.22%, which represents the midpoint between the 8.53% average result reached by my application of the DCF and CAPM models and the 9.9% ROE currently authorized for the Company.

Q Why are you recommending an ROE higher than the result identified by the financial models?

A My recommendation is informed by the principle of gradualism. Any significant changes in Consumers Energy's ROE should be implemented gradually so as not to create

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unnecessary instability in the company's market value, which is based in part on the outcomes of regulatory proceedings like this one.

Capital Asset Pricing Model (CAPM)

Q What is the CAPM?

A The CAPM is an approach to cost of equity estimation that assumes that company-specific risk, such as the risk of a specific company's product line failing, can be diversified away by an investor by investing in a market portfolio of stocks. The risk that cannot be diversified away is market (also known as systematic) risk, such as the risk created by macroeconomic fluctuations. The CAPM thus defines the risk of investing in a security as a function of systematic risk.

The CAPM defines the expected return of a security as follows:

$$\text{Expected Return} = \text{Risk-free Rate} + \text{Risk Premium}$$

Where the risk premium is:

$$\text{Risk Premium} = \text{Beta} \times \text{Equity Risk Premium}$$

I will describe the precise definitions of beta and the equity risk premium later in my testimony.

Q Please describe your application of the CAPM to estimate the ROE.

A My CAPM analysis follows the same basic formula as Ms. Bulkley's. However, the values we use for several important inputs to the formula – the equity risk premium (ERP), beta

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1 and the risk-free rate – differ, for reasons I explain below. I provide my CAPM estimate in
2 Exhibit CUB-5.¹⁷

3 **Q What is the ERP?**

4 **A** The ERP is an essential component of the CAPM formula. It represents the excess return
5 an investor would receive over the risk-free rate by investing in the broader equity market.
6 The ERP is calculated as the estimated return on the market an investor can expect from
7 investing in the broad stock market minus the risk-free rate.

8 It is important when estimating the ERP to not be overly reliant on historical data. While
9 historical estimates of ERP are commonly used by the financial community, that popularity
10 does not make them less flawed. As New York University Stern School of Business
11 Professor Aswath Damodaran, one of the most highly respected and widely cited experts
12 in finance and valuation, has written:

13 Given how widely the historical risk premium approach is used, it is
14 surprising how flawed it is and how little attention these flaws have
15 received.¹⁸

16 There are two main reasons that over-reliance on historical data is problematic. First, the
17 historical estimate for ERP is extremely sensitive to the historical time period selected,

¹⁷ Exhibit CUB-5, CAPM Analysis.

¹⁸ Aswath Damodaran, “Estimating Equity Risk Premiums,” Stern School of Business, accessed June 2025, available at <https://pages.stern.nyu.edu/~adamodar/pdfiles/papers/riskprem.pdf>.

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1 meaning that the subjective judgment by the person deciding which time period to collect
2 market data for has an outsized impact on the result.¹⁹

3 Second, regardless of the time period selected, historical estimates of ERP are subject to
4 the problem of survivorship bias, where returns that are counted in historical ERPs tend to
5 be those from stocks that remain in the market, rather than those that drop out. This
6 survivorship bias effect tends to inflate historical ERPs.²⁰

7 **Q Are there any methods of estimating ERP not subject to these problems?**

8 **A** Yes. Dr. Damodaran suggests using an “implied equity risk premium” method. This
9 approach values stocks in a market at the present value of dividends from each stock
10 growing at a constant rate. Essentially, Dr. Damodaran takes the same discounted cash flow
11 model Ms. Bulkley and I use to estimate the cost of equity for a single company and applies
12 it to value the expected return of a broad market index, the S&P 500. Dr. Damodaran
13 explains that this approach has the advantage of being “market-driven and current, and
14 does not require any historical data.”²¹

15 Dr. Damodaran’s formula, summarized in the figure below, begins with the base level of
16 aggregate earnings of the S&P 500 index, and then applies the basic assumption of the
17 discounted cash flow model that the present value of an asset is the stream of cash flows it

¹⁹ *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.”

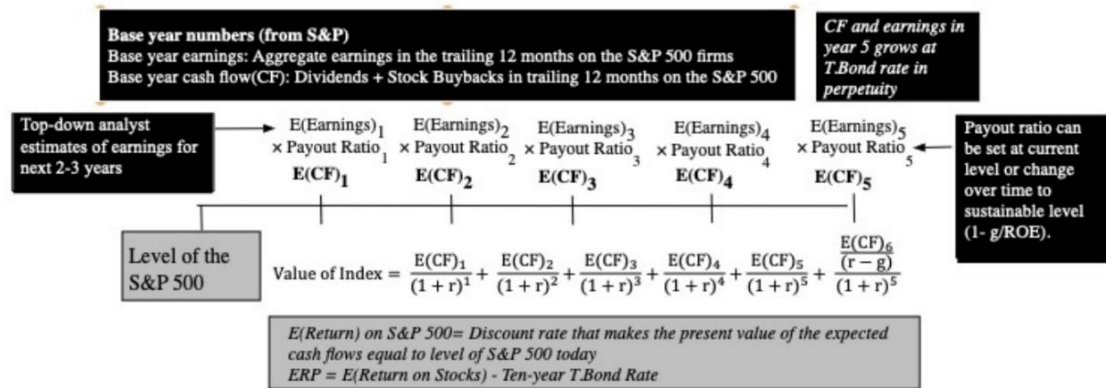
²⁰ *Id.* “...the survivor bias will result in historical premiums that are larger than expected premiums for markets like the United States, even assuming that investors are rational and factor risk into prices.”

²¹ *Id.*

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is expected to generate, with each cash flow discounted at a rate that reflects the time value of money.

Fig. 3²²



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.

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

²² Reproduced from Damodaran, "Equity Risk Premiums (ERP): Determinants, Estimation, and Implications – The 2025 Edition," March 2025, p. 96. https://papers.ssrn.com/sol3/papers.cfm?abstract_id=5168609

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1 over the last decade. For my ERP,²³ I use the average of five different estimates for ERP
2 from Dr. Damodaran calculated in June 2025. I use the highest estimate to be more
3 conservative.

4 So as not to be reliant on one source, I also used the recommended U.S. ERP from financial
5 research firm Kroll for 2025.²⁴ Kroll's recommended U.S. ERP is based on risk perceptions
6 in the market and other qualitative and quantitative inputs, such as an implied equity risk
7 premium model.

8 **Q Is the ERP you calculate forward-looking to account for the fact that the test year for**
9 **this proceeding is in the future?**

10 **A** Yes. Dr. Damodaran's ERP is purposely calculated to be forward-looking in order to avoid
11 the aforementioned pitfalls with historical approaches for ERP.²⁵ More specifically, Dr.
12 Damodaran calculates the ERP using an expected growth rate for payouts to investors (i.e.,
13 dividends and stock buybacks) that is the average of two-year growth forecasts of the
14 aggregate earnings of the S&P 500 Index from analysts from Thomson Reuters, Factset,
15 Yardeni, and S&P Capital IQ.

²³ See Exhibit CUB-3, Equity Risk Premium.

²⁴ Kroll, "Kroll Recommended U.S. Equity Risk Premium and Corresponding Risk-Free Rates to be Used in Computing Cost of Capital: January 2008 - Present," April 25, 2025. <https://www.kroll.com/en/reports/cost-of-capital/recommended-us-equity-risk-premium-and-corresponding-risk-free-rates>

²⁵ "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, "Equity Risk Premiums," p. 93.

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1 **Q** **Does Ms. Bulkley calculate the ERP she uses for her CAPM analysis using the same**
2 **method as Dr. Damodaran?**

3 **A** No. Ms. Bulkley uses a very different methodology. Her expected return on the market is
4 the addition of a) a Bloomberg forecast of the three-to-five-year growth rate for earnings
5 per share of companies in the S&P 500 Index and b) a Bloomberg estimate of the dividend
6 yield of companies in the S&P 500 Index. This formula, where (cost of equity) = expected
7 dividend yield plus g [growth rate], is essentially a simplified version of the discounted
8 cash flow formula used by Dr. Damodaran and many others. This methodology assumes
9 that cash flows will grow in the long term at a constant rate based on analyst expectations
10 of the next five years, rather than settling at a more sustainable long-term rate based on the
11 risk-free rate, as Dr. Damodaran does.

12 **Q** **Why is Ms. Bulkley's ERP estimate so much higher than yours?**

13 **A** Ms. Bulkley has used an inflated estimate for g , since it assumes that long-term growth
14 rates will continue to remain high over the long run. The consequence of that choice is
15 further amplified by her use of a more simplified discounted cash flow, which makes her
16 result much more sensitive to the level at which g is set because g is only one of two inputs
17 to her formula (the other input being the dividend yield).

18 **Q** **Why is it unreasonable to assume that the long-term growth rate will remain higher**
19 **than the risk-free rate?**

20 **A** Ms. Bulkley's approach assumes that cash flows will grow in the long term at a constant
21 rate based on analyst expectations of the next five years. It is unrealistic to assume that
22 earnings can grow in perpetuity at such a high rate. Dr. Damodaran's assumption that

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1 growth will settle to a more sustainable rate is much more appropriate for a realistic
2 application of the discounted cash flow model. This problem with Ms. Bulkley's approach
3 will surface again when I discuss her DCF analysis for ROE.

4 **Q What risk-free rate did you use in your CAPM formula?**

5 **A** To be consistent with my two ERPs, I used two corresponding risk-free rates. First, I used
6 the same risk-free rate of 4.23%, representing the current yield on long-term Treasury
7 bonds, that Dr. Damodaran used to calculate his ERP for September 2025. Second, I
8 followed Kroll's recommended method for the risk-free rate and used the spot 20-year
9 Treasury yield of 4.76%. Specifically, I calculated the average of the high and low 20-year
10 Treasury yields from September 5, 2025. My equity risk premiums and corresponding risk-
11 free rates are shown in Exhibit CUB-3.

12 **Q Explain how you arrived at the beta used in your CAPM formula.**

13 **A** The beta coefficient is a measure of the sensitivity of a company's returns to the returns of
14 the market as a whole – how much the historical returns mathematically vary compared to
15 the variance of the historical returns of the market. Its relevance for the CAPM formula is
16 that it measures the risk associated with investing in the company's equity that cannot be
17 eliminated through portfolio diversification. In theory, an investor can buy other stocks in
18 the market to compensate for the risk of any one stock, but if that stock's returns are heavily
19 correlated with the returns of the market, the investor is essentially not diversifying away
20 the stock's risk because it is merely adding more of the same kind of risk. Thus, beta is
21 often described as a measure of "systematic risk" – the financial risk of a company that is

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1 not the result of risks from the company itself, but from its performance relative to the
2 market as a whole (the “system”).

3 While calculating beta for publicly traded stocks is fairly straightforward due to the
4 availability of plentiful data on a stock’s performance relative to the market, even a
5 company that is not publicly traded, such as Consumers Energy, carries systematic risk vis-
6 à-vis the market that can be calculated as a beta coefficient.

7 I use as beta in my CAPM formulas two different averages: First, the average of the Value
8 Line beta estimates for the companies in my proxy group, and second, the average of the
9 Bloomberg beta estimates for the companies in my proxy group. But for each of these two
10 betas, I make an important adjustment that makes the beta coefficient more accurate.

11 **Q Please explain the adjustment you made to beta.**

12 **A** As shown in Exhibit CUB-4, I remove an adjustment that has been made to the Bloomberg
13 and Value Line betas by those data sources, since this adjustment should not be applied to
14 rate-regulated utilities.²⁶ Bloomberg and Value Line use the “Blume adjustment” equation
15 to convert “raw” betas to “adjusted” betas. The Blume adjustment is meant to remove the
16 bias that stems from the long-run tendency of betas to regress to 1. For stocks in most
17 industries, this tendency of betas is thought to be a result of efforts by management to keep
18 the systematic risk of a given firm close to that of the market.²⁷

²⁶ Exhibit CUB-4, Beta.

²⁷ Michelfelder, “Public Utility Beta Adjustment and Biased Costs of Capital in Public Utility Rate Proceedings,” The Electricity Journal, 2013. <https://www.sciencedirect.com/science/article/abs/pii/S1040619013002340>

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1 But this assumption that betas revert to the mean does not hold when it comes to the betas
2 of rate-regulated utilities. The ability to recover costs inoculates rate-regulated utilities
3 from systematic risk. Rate regulation protects investor-owned utilities like Consumers
4 Energy from the risks of rising expenses, commodity price risk, and competitive risks, and
5 they enjoy natural monopolies that mitigate market risks associated with the customer base.
6 For example, commodity prices tend to be passed through directly to customers, and
7 utilities can request a rate increase if sales decline. As a result, the Blume adjustment is not
8 appropriate to apply to the betas of companies like those in the Company's proxy group.

9 **Q Is the removal of the Blume adjustment supported by any evidence?**

10 **A** Yes. There is extensive academic literature supporting the inapplicability of the Blume
11 adjustment when it comes to utilities. The theoretical argument that the unique
12 characteristics of rate regulation reduce systematic risk for utility stocks is well-supported.
13 Utility stock performance tends to be countercyclical, so betas tend to be less than 1.²⁸
14 There is also a strong empirical record in the academic literature showing that rate-
15 regulated utility stock betas in practice do not revert to 1. An analysis of the monthly returns
16 of stocks of 57 publicly traded electric and gas utilities from 1962 to 2007 found that the

²⁸ 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>

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1 mean and median betas decline over time, rather than rise to 1, as the Blume adjustment to
2 beta assumes.²⁹

3 **Q Please summarize how you arrived at the ROE using the CAPM.**

4 **A** I calculated the cost of equity using four different CAPM formulas to account for two
5 different ERPs (Damodaran and Kroll) and two different average betas (Value Line and
6 Bloomberg). I provide the four resulting ROEs in Exhibit CUB-5.

7 **Q Did you apply the CAPM formula to estimate a cost of equity for the U.S. stock**
8 **market?**

9 **A** Yes. The expected return of the U.S. stock market can be calculated using the same inputs
10 as above but using a beta of 1. I show my calculation of a 9.02% return for the U.S. stock
11 market in Exhibit CUB-10.

²⁹ These results “strongly refute the validity of the Blume equation for public utility stocks.” Michelfelder 2013.

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1 **Q Why did you not use the ECAPM?**

2 **A To my knowledge, the Commission has never recognized the ECAPM as a valid**
3 methodology for estimating ROE.³⁰ The MPSC Staff has also historically declined to use
4 the ECAPM model as part of its ROE analyses.³¹

5 ***Discounted Cash Flow (DCF) Model***

6 **Q Please explain your application of the Discounted Cash Flow (DCF) model to estimate**
7 **the Company's cost of equity.**

8 **A I add the Company's growth rate, or g, to the dividend yields of each company in my proxy**
9 group to arrive at an estimated cost of equity. My DCF result is lower than Ms. Bulkley's
10 primarily due to correcting for Ms. Bulkley's use of an unrealistic growth rate.

11 **Q Why is the growth rate you have selected superior to that selected by Ms. Bulkley?**

12 **A Selecting the growth rate may be the most important element of the DCF analysis. The EPS**
13 projections used by Ms. Bulkley are all in the short term: five-year consensus analyst
14 earnings per share growth estimates. But a short-term growth rate cannot be the only
15 growth rate used in the DCF model.

Case No. U-21389, Notice of Proposal for Decision, Dec, 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." <https://mi-psc.my.site.com/sfc/servlet.shepherd/version/download/0688y00000BCjcrAAD>; 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.").

³¹ For example, see Case No. U-20940, Direct Testimony of MPSC Staff Witness Joseph Ufolla, 5 TR 1869, lines 9-16.

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1 The use of only short-term rates for perpetual growth leads to a wildly unrealistic outcome.
2 Ms. Bulkley's estimate for g is significantly higher than conservative forecasts for long-
3 run domestic economy growth. For example, the average of her EPS growth rates is
4 6.48%³², which is over 70% higher than the Congressional Budget Office's forecast of
5 3.80% for the average annual GDP growth of the U.S. economy from 2028 to 2035.³³ A
6 DCF growth rate input higher than the growth rate of the economy as a whole implies that,
7 in the long run, the Company will grow larger than the entire U.S. economy. Such an
8 outcome is impossible.³⁴ I have corrected for this unrealistic assumption in my DCF model.

9 **Q Explain how you selected the g you use in your DCF model.**

10 **A** My DCF analysis is presented in Exhibits CUB-7 and CUB-8. I use two versions of the
11 DCF model.³⁵

12 First, I use a two-stage DCF model that includes a weighted average of a short-term growth
13 rate based on investor expectations of utility earnings growth and a long-term growth rate
14 that matches investor expectations of the growth of the domestic economy as a whole. The
15 formula for this model is essentially the same as that in the model used by Ms. Bulkley:

$$ke = (D_1/P_0) + g.$$

³² Exhibit A-14, Sched. D-5, p. 3.

³³ Exhibit CUB-6, Long-Term Growth Rate.

³⁴ 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.")

³⁵ Exhibit CUB-7, DCF (with Earnings Growth Rates); and Exhibit CUB-8, DCF (with Dividend Growth Rates).

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1 Where ke is the cost of equity, D_1 is the dividend at time 1, P_0 is the stock price at time 0,
2 and g is the growth rate.

3 But whereas in Ms. Bulkley's model, g is merely the short-term earnings projection, in the
4 two-stage model g is a composite of the short-term projection and the long-term growth
5 rate that represents the proper bound for the Company's long-term growth, reflecting that
6 in the long term the Company cannot grow larger than the domestic economy of which it
7 is a part. The reason for this two-step process is that short-term and long-term growth often
8 differ and failing to account for those differences leads to an incorrect application of the
9 DCF model.³⁶

10 My method follows FERC's approved methodology used to analyze the base ROE of a
11 public utility's rates under the Federal Power Act using the DCF model. FERC has
12 endorsed a two-step model in which the short-term growth rate is weighed at 80% and the
13 long-term growth rate is weighed at 20%.³⁷ I use those same weightings in my model.
14 Specifically, I weighed the short-term growth rates for each proxy group company from
15 Exhibit A-14, Schedule D-5, page 3 at 80%, and the long-term growth rate at 20%.

16 Candidates for long-term growth rates are listed in Exhibit CUB-6, and they each represent
17 conservative estimates of long-term economic growth.³⁸ I conservatively select the highest

³⁶ "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.

³⁷ FERC, Order in Docket EL14-12-016, Oct. 17, 2014, p. 13. Available at <https://www.ferc.gov/media/e-4-el14-12-016>

³⁸ Exhibit CUB-6, Long-Term Growth Rate Sources.

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1 of these candidates, the nominal GDP growth rate from 2028 to 2035, as the value for the
2 long-term g used in the DCF formula.

3 Second, I use another version of the DCF model that is identical to the first except the
4 short-term growth rate is the average of the Value Line forecasts for dividend per share
5 growth of the proxy group companies, rather than an average of forecasts for earnings
6 growth. Regulatory jurisdictions such as the Massachusetts Department of Public Utilities
7 have recognized that DPS growth rates carry the advantage that firms tend to keep their
8 dividend growth stable over time, as opposed to EPS growth rates, which may vary based
9 on firm-specific events and economic conditions.³⁹ With that advantage in mind, I include
10 a version of the DCF model using dividend growth rates rather than earnings growth rates
11 in order to reduce the uncertainty that comes from relying on a single version.

12 **Q How else does your DCF model differ from Ms. Bulkley's?**

13 **A** To calculate the stock prices used to arrive at dividend yields, Ms. Bulkley uses prices
14 averaged over 30-, 90- and 180-trading-day periods. To reflect current investor
15 expectations, the stock price should be as close to the current spot price as possible.
16 Averaging prices over a short time period to remove the risk of picking an outlier price is
17 appropriate, but the 90- and 180-day periods selected by Ms. Bulkley run the risk of relying
18 on stale information.⁴⁰

³⁹ Massachusetts Department of Public Utilities, Order in DPU 23-80 and 23-81, June 28, 2024.

⁴⁰ 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

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1 My stock prices represent the average of the high and low prices over the 30-day period
2 ending September 4, 2025, with prices obtained from Yahoo! Finance. This ensures that
3 my analysis uses the most up-to-date information, rather than data that is six months old
4 and no longer reflective of investor expectations.

5 ***BYRP***

6 **Q Should the Commission consider Ms. Bulkley's Bond Yield Risk Premium (BYRP)**
7 **analysis for estimating ROE?**

8 **A** No, it should not. It should be disregarded because it introduces into the calculation of
9 ROE, a process that should be based on objective data as much as possible, the reliance on
10 ROEs set by other regulatory commissions. Setting the ROE based on comparisons to other
11 jurisdictions is both circular and unlikely to result in returns that would be set by objective
12 financial methodology. Instead, it would likely result in the continuation of excessively-
13 high ROEs, as shown by the research regarding trends in commissions setting excessive
14 utility ROEs.

15 **Q Please explain how the risk premium is determined in Ms. Bulkley's analysis.**

16 **A** The risk premium used in Ms. Bulkley's BYRP analysis is the spread between those ROEs
17 historically set by other commissions in rate cases and long-term Treasury bond yields.
18 Therefore, the resulting risk premium she calculates is as large as it is because it reflects

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-month period rather than a 10-day period would not be unreasonable.”

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1 the extent to which regulatory commissions set ROEs at a premium to what the ROEs
2 would be using only objective financial methods. In other words, her methodology
3 perpetuates any excessive ROEs in her data.

4 **Q Have any other jurisdictions recognized this problem with the BYRP method?**

5 **A** Yes. This problem with similar Risk Premium models has been cited by FERC as one of
6 the reasons to reject the use of the model. In Opinion No. 569 in a 2019 order, FERC found
7 that “while all models, including the DCF, feature some circularity, such circularity is
8 particularly direct and acute with the Risk Premium model because it directly relies on past
9 Commission ROE decisions.”⁴¹ In that decision, FERC also rejected the use of the Risk
10 Premium model because it is “largely redundant with the CAPM.”

11 ***Risk Profile***

12 **Q Ms. Bulkley claims that Consumers Energy’s level of capital expenditures gives the**
13 **Company higher risk relative to the proxy group, and that if the Company’s proposed**
14 **infrastructure recovery mechanism is not approved, this additional risk “supports an**
15 **ROE toward the higher end of the reasonable range of ROEs.”⁴² Did you adjust your**
16 **ROE results to reflect risk from capital expenditures?**

17 **A** No. In my opinion, these risks have already been accounted for in Consumers Energy’s
18 credit rating, which, as I will show, compares favorably to the ratings of the proxy group

⁴¹ FERC Opinion 569, 169 FERC 61129 (2019), par. 343. Available at: https://www.ferc.gov/sites/default/files/2020-04/E-11_1.pdf. As the PFD in Consumers Energy’s most recent gas rate case, Case No. U-21806, noted, FERC “subsequently backtracked and reinstated the risk premium approach upon a rehearing, but on appeal the U.S. Court of Appeals for the District of Columbia Circuit vacated the order holding that FERC acted arbitrarily and capriciously by reinstating the risk premium approach without refuting its own withering criticisms of the model’s deficiencies.” Case No. U-21806, PFD, p 283 (citations omitted).

⁴² Bulkley Direct, p. 46, lines 16-17.

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1 companies, indicating that the Company is not at higher risk due to its planned capital
2 expenditures.

3 I agree with Ms. Bulkley that capital expenditures can affect a utility's risk in two ways:
4 "the heightened level of investment increases the risk of under-recovery or delayed
5 recovery of the invested capital; and (2) an inadequate return would put downward pressure
6 on key credit metrics."⁴³ Ms. Bulkley then goes on to explain how credit rating agencies
7 take these two risk factors into account when issuing their ratings.⁴⁴

8 Therefore, we can look to the ratings received by the Company and the proxy group
9 companies to consider how they compare to each other in terms of the level of risk related
10 to capital expenditures.

11 **Q How does the Company's credit rating compare to the ratings of the proxy group**
12 **companies?**

13 **A** Consumers Energy currently has an A- long-term credit rating from S&P.⁴⁵ That rating is
14 higher than the ratings for all but 5 of the 19 proxy group companies. In other words,
15 Consumers Energy has a higher rating than 73.6% of the proxy group.

16 **Q What conclusion do you draw from this comparison?**

17 **A** The Company does not appear to be regarded by the credit rating agencies as higher risk
18 than the average proxy group company; in fact, it is regarded as lower risk. While

⁴³ Bulkley Direct, p. 42, lines 7-10.

⁴⁴ Bulkley Direct, p. 43.

⁴⁵ Bulkley Direct, p. 19, line 7.

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1 Consumers Energy may have a more ambitious capital spending program than the average
2 proxy group company, that program has not translated to higher risk.

3 **Q Did you adjust your recommended return on equity based on regulatory risk?**

4 **A** No. According to Ms. Bulkley, “both Moody’s and S&P have identified the supportiveness
5 of the regulatory environment as an important consideration in developing their overall
6 credit ratings for regulated utilities.”⁴⁶ Therefore, much like with the issue of capital
7 expenditures, the issue of regulatory risk is already accounted for in the credit rating. Since
8 Consumers Energy’s credit rating is higher than that of most of the proxy group companies,
9 I do not adjust my ROE results for regulatory risk.

10 **V. CAPITAL STRUCTURE**

11 **Q What is the Company’s current authorized capital structure, and does the utility**
12 **propose any changes to this structure?**

13 **A** The utility’s current authorized capital structure is 50% common equity and 50% long-
14 term debt. In this case the Company proposes a structure of 50.75% common equity,
15 49.11% long-term debt and 0.14% preferred stock.⁴⁷

16 **Q What criteria determine the optimal division of equity and debt in the Company’s**
17 **capital structure?**

18 **A** Deciding the optimal capital structure for a company like Consumers Energy involves
19 weighing the different elements of risk that come with debt vs. equity. Theoretically

⁴⁶ Bulkley Direct, p. 52, lines 24-26.

⁴⁷ Exhibit A-14, Sched. D-1.

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1 speaking, the cost of equity is always higher than the cost of debt because of two main
2 factors. First, equity holders inherently take on more risk because they come second to debt
3 holders when it comes to the legal ownership of the assets of the firm. For example, if the
4 firm were to declare bankruptcy, debt holders would have priority under law to be repaid
5 for their ownership claim, and whatever portion of assets left after debt holders are repaid
6 may or may not be enough to satisfy the equity holders' actual claim. Second, interest
7 payments on debt are tax deductible, reducing the cost of financing with debt.

8 As a result of the higher cost of equity, financing a firm with greater amounts of equity
9 tends to be more expensive than financing with greater amounts of debt, and in the context
10 of a utility, leads to higher costs for ratepayers.⁴⁸

11 Debt, however, carries with it its own financial risk. As a firm adds more and more debt,
12 the risk of it being unable to repay that debt increases, and this riskiness can be observed
13 through the firm's credit rating. The goal of determining the optimal capital structure is to
14 determine the point at which the cost of increasing the firm's cost of capital by adding more
15 equity does not outweigh the additional financing costs of adding more debt, and vice
16 versa. As Dr. Morin puts it:

17 The burning question to answer is at what level of leverage is the low-cost
18 advantage of debt financing offset by the rising risks?⁴⁹

⁴⁸ Morin, p. 559. "The correct proportion of debt and equity capital for a utility to employ is particularly relevant for utility ratepayers, since equity costs exceed debt costs..."

⁴⁹ Morin, p. 559.

**DIRECT TESTIMONY OF MATTHEW BANDYK ON BEHALF OF CUB
CASE NO. U-21870**

1 **Q** **Is the capital structure proposed by the Company in this case the optimal capital**
2 **structure?**

3 **A** No. My analysis shows that the Company could use less equity in its capital structure and
4 still maintain the same credit rating. The result of my analysis shows that the Company's
5 proposed capital structure would therefore unnecessarily burden ratepayers due to an
6 excessive amount of equity, a more costly form of financing.

7 **Q** **Please explain your analysis of the optimal capital structure.**

8 **A** My analysis uses a standard approach in finance to calculate the interest coverage ratio
9 implied by the proposed capital structure. The interest coverage ratio measures a
10 company's ability to pay its interest obligations and is one of the most important factors
11 used by bond rating agencies to determine the creditworthiness of a company's debt. The
12 coverage ratio is calculated as:

13 [the weighted pre-tax cost of debt (weighted by the percent of debt in the
14 capital structure) plus the weighted pre-tax cost of equity (weighted by the
15 percent of equity in the capital structure)] divided by the weighted pre-tax
16 cost of debt.

17 In Exhibit CUB-9, I have calculated the coverage ratio for the Company.⁵⁰

18 This coverage ratio implies a level of financial risk that implies what bond rating a
19 company's debt is likely to receive at that ratio. This implied rating can be observed by
20 looking at the range of coverage ratios that are typical for companies whose debt receives
21 a certain rating. Dr. Damodaran maintains a table of coverage ratio ranges and the

⁵⁰ Exhibit CUB-9, Interest Coverage Ratios.

**DIRECT TESTIMONY OF MATTHEW BANDYK ON BEHALF OF CUB
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1 associated bond credit rating that is frequently updated with data from all rated companies
2 in the U.S.⁵¹ This table allows me to compare the coverage ratio calculated in Exhibit CUB-
3 9 to the ratio range of 3 to 4.2499 for A3/A- -rated debt. Consumers Energy's long-term
4 credit rating is A- from S&P and A3 from Moody's.⁵²

5 **Q Could the Company lower its proposed 50.75% equity ratio without lowering its**
6 **coverage ratio below the range of coverage ratios required for an A3/A- rating?**

7 **A** Yes. My calculation in Exhibit CUB-9 shows that at the Company's desired 10.25% ROE,
8 50.75% equity ratio, 4.54% cost of debt, and 49.11% debt ratio, the coverage ratio is 4.17,
9 at the higher end of the range of 3 to 4.2499 identified in Dr. Damodaran's table. My
10 calculation then shows that at the same cost of debt but using a 50/50 debt-equity ratio and
11 my recommended ROE, the coverage ratio falls to just 4.04, still well within the range.
12 This result suggests that the Company could lower the equity share in its capital structure,
13 and thus lower its cost of capital, without materially increasing financial risk.

14 **Q Mr. Bleckman claims that the Company's proposed equity ratio and ROE results in**
15 **an "optimal outcome"⁵³ for the Company and its customers. Do you agree?**

16 **A** No. An equity ratio and ROE lower than the Company's proposal would result in a more
17 optimal outcome because it would minimize the cost of capital, reducing costs for
18 customers. Mr. Bleckman does not provide any quantitative analysis as to how the

⁵¹ Aswath Damodaran. "Ratings, Interest Coverage Ratios and Default Spread." https://pages.stern.nyu.edu/~adamodar/New_Home_Page/datafile/ratings.html. Accessed August 2025.

⁵² Bulkley Direct, p. 19, lines 6-8.

⁵³ Direct Testimony of Marc R. Bleckman, p. 22, line 5.

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1 Company's proposal is optimal. He simply asserts that the impact on customer rates is
2 "reasonable" without explaining why customers should have to pay for a higher rate of
3 return without a corresponding benefit.

4 **Q Mr. Bleckman asserts that "further degradation of the authorized equity ratio and**
5 **ROE puts the Company at risk of dropping further in its regulatory environment**
6 **rankings which could negatively impact the Company's credit quality and credit**
7 **rating."⁵⁴ Do you agree?**

8 **A** No. Mr. Bleckman does not provide any evidence that the Company is at risk of a credit
9 downgrade from a drop in regulatory environment rankings or why his preferred equity
10 ratio and ROE would prevent such a drop from occurring. For example, Mr. Bleckman
11 claims that a "supportive" equity ratio and ROE are "critical in maintaining a 'financial
12 cushion' to protect against downgrade in the event of unforeseen events like the market
13 volatility and disruption that occurred during the onset of the COVID-19 pandemic in 2020
14 or the financial pressure caused by the dramatic increase in gas prices and interest rates in
15 2022 or the banking crisis of 2023."⁵⁵ But Mr. Bleckman provides no analysis showing
16 that his preferred equity ratio and ROE are required to maintain the Company's credit
17 ratings in this sense. In addition, both Moody's⁵⁶ and S&P⁵⁷ have a "stable" outlook for
18 Consumers Energy, meaning they see little risk of a downgrade.

⁵⁴ Bleckman Direct, p. 20, lines 12-15.

⁵⁵ Bleckman Direct, p. 21, lines 22-25.

⁵⁶ Exhibit A-37 (MRB-18), p. 1.

⁵⁷ Exhibit A-36 (MRB-17), p. 1.

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1 **Q** **Mr. Bleckman also asserts that the company’s credit rating is put “at risk” from the**
2 **lower Funds from Operations-(FFO)to-Debt ratio that would result from a lower**
3 **equity ratio and/or ROE. ⁵⁸ Do you agree?**

4 **A** No. Mr. Bleckman claims that the 50.75% equity ratio and 10.25% ROE “results in an
5 FFO-to-Debt ratio that is sufficient in striking this balance,” namely, “the balance between
6 the Company’s equity ratio and ROE that will ensure that this key financial metric does
7 not degrade and cause significant credit deterioration.”⁵⁹ But in response to a discovery
8 question I submitted asking what this sufficient FFO-to-Debt ratio is, Mr. Bleckman
9 responded that the calculation of this ratio was not available because “a calculation of the
10 FFO-to-Debt ratio is not feasible using only the proposed 50.75% equity ratio and 10.25%
11 ROE.” If he has not calculated the FFO-to-Debt ratio, Mr. Bleckman cannot possibly know
12 if the FFO-to-Debt ratio resulting from the proposed equity ratio and ROE would be
13 “sufficient” toward preserving the Company’s credit rating, or if a lower equity ratio and/or
14 ROE would be insufficient.

15 **Q** **What capital structure do you propose the Commission adopt in this case?**

16 **A** I recommend the Commission maintain the Company’s authorized capital structure of 50%
17 common equity and 50% long-term debt.

18 **Q** **Does this conclude your testimony?**

19 **A** Yes.

⁵⁸ Bleckman Direct, p. 16, lines 8-9.

⁵⁹ Bleckman Direct, p. 13, lines 13-16.

1 MR. BZDOK: Thank you. At this time, on behalf
2 of NRDC, Sierra Club, and CUB, I would move to bind into
3 the record the direct testimony of Douglas Jester, which
4 consists of a cover page, a table of contents, 27 pages of
5 questions and answers, and I would move for the admission
6 into evidence of Exhibits CUB-11 through CUB-20.

7 JUDGE THOITS: Are there any objections to the
8 admission of this testimony or these exhibits?

9 Hearing none. The direct testimony of Douglas
10 Jester is bound into the record and Exhibits CUB-11
11 through CUB-20 are admitted.

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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
generation and distribution of electricity
and for other relief

U-21870

DIRECT TESTIMONY OF DOUGLAS B. JESTER
ON BEHALF OF
NATURAL RESOURCES DEFENSE COUNCIL, SIERRA CLUB, AND
CITIZENS UTILITY BOARD OF MICHIGAN

September 30, 2025

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CASE NO. U-21870**

I. INTRODUCTION & QUALIFICATIONS

Q. Please state for the record your name, position, and business address.

A. My name is Douglas B. Jester. I am Managing Partner of 5 Lakes Energy, a Michigan limited liability corporation, located at PO Box 869, Northport, Michigan 49670.

Q. On whose behalf is this testimony being offered?

A. I am testifying on behalf of the Natural Resources Defense Council ("NRDC"), Sierra Club, and Citizens Utility Board of Michigan ("CUB"), collectively identified as "NSC."

Q. Please summarize your experience in the field of utility regulation.

A. I have worked for more than 30 years in utility industry regulation and related fields. My work experience is summarized in my resume, provided as Exhibit CUB-11.

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 U-17473 (Consumers Energy Company Plant Retirement Securitization);
- Case U-17096-R (Indiana Michigan 2013 PSCR Reconciliation);
- Case U-17301 (Consumers Energy Renewable Energy Plan 2013 Biennial Review);
- Case U-17302 (DTE Energy Renewable Energy Plan 2013 Biennial Review);
- Case U-17317 (Consumers Energy 2014 PSCR Plan);
- Case U-17319 (DTE Electric 2014 PSCR Plan);
- Case U-17671-R (UPPCO 2015 PSCR Reconciliation);
- Case U-17674 (WEPCO 2015 PSCR Plan);

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- 1 • Case U-17674-R (WEPCO 2015 PSCR Reconciliation);
- 2 • Case U-17679 (Indiana-Michigan 2015 PSCR Plan);
- 3 • Case U-17688 (Consumers Energy Cost of Service and Rate Design);
- 4 • Case U-17689 (DTE Electric Cost of Service and Rate Design);
- 5 • Case U-17698 (Indiana-Michigan Cost of Service and Rate Design);
- 6 • Case U-17735 (Consumers Energy General Rates);
- 7 • Case U-17752 (Consumers Energy Community Solar);
- 8 • Case U-17762 (DTE Electric Energy Optimization Plan);
- 9 • Case U-17767 (DTE General Rates);
- 10 • Case U-17792 (Consumers Energy Renewable Energy Plan Revision);
- 11 • Case U-17895 (UPPCO General Rates);
- 12 • Case U-17911 (UPPCO 2016 PSCR Plan);
- 13 • Case U-17911-R (UPPCO 2016 PSCR Reconciliation);
- 14 • Case U-17990 (Consumers Energy General Rates);
- 15 • Case U-18014 (DTE General Rates);
- 16 • Case U-18089 (Alpena Power PURPA Avoided Costs);
- 17 • Case U-18090 (Consumers Energy PURPA Avoided Costs);
- 18 • Case U-17911-R (UPPCO 2016 PSCR Reconciliation);
- 19 • Case U-18091 (DTE PURPA Avoided Costs);
- 20 • Case U-18092 (Indiana Michigan Power Company PURPA Avoided Costs);
- 21 • Case U-18093 (Northern States Power PURPA Avoided Costs);
- 22 • Case U-18094 (Upper Peninsula Power Company PURPA Avoided Costs);
- 23 • Case U-18095 (Wisconsin Public Service Company PURPA Avoided Costs);

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- 1 • Case U-18096 (Wisconsin Electric Power Company PURPA Avoided Costs);
- 2 • Case U-18224 (UMERC Certificate of Necessity);
- 3 • Case U-18232 (DTE Renewable Energy Plan);
- 4 • Case U-18255 (DTE Electric General Rates);
- 5 • Case U-18322 (Consumers Energy General Rates);
- 6 • Case U-18406 (UPPCO 2018 PSCR Plan);
- 7 • Case U-18408 (UMERC 2018 PSCR Plan);
- 8 • Case U-18419 (DTE Certificate of Necessity);
- 9 • Case U-20072 (UPPCO 2017 PSCR Reconciliation);
- 10 • Case U-20111 (UPPCO Tax Cuts and Jobs Act of 2017 Adjustment);
- 11 • Case U-20134 (Consumers Energy General Rates);
- 12 • Case U-20150 (UPPCO Revenue Decoupling Mechanism Complaint);
- 13 • Case U-20162 (DTE General Rates);
- 14 • Case U-20165 (Consumers Energy Integrated Resource Plan);
- 15 • Case U-20229 (UPPCO 2019 PSCR Plan Case);
- 16 • Case U-20276 (UPPCO General Rates);
- 17 • Case U-20350 (UPPCO Integrated Resource Plan);
- 18 • Case U-20359 (I&M 2019 General Rate Case);
- 19 • Case U-20471 (DTE Integrated Resource Plan);
- 20 • Case U-20479 (SEMCO 2019 General Rate Case);
- 21 • Case U-20561 (DTE 2019 General Rate Case);
- 22 • Case U-20591 (Indian Michigan Power Company IRP);
- 23 • Case U-20642 (DTE Gas 2020 General Rate Case);

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- 1 • Case U-20649 (Consumers Electric Voluntary Green Pricing);
- 2 • Case U-20650 (Consumers Gas 2020 General Rate Case);
- 3 • Case U-20697 (Consumers Electric 2020 General Rate Case);
- 4 • Case U-20713 (DTE 2020 Voluntary Green Pricing);
- 5 • Case U-20836 (DTE Electric 2022 General Rate Case);
- 6 • Case U-20874 (Alpena Power 2022-23 EWR Plan Case);
- 7 • Case U-20875 (Consumers Energy 2022-23 EWR Plan Case);
- 8 • Case U-20876 (DTE Electric 2022-23 EWR Plan Case);
- 9 • Case U-20877 (Indiana Michigan 2022-23 EWR Plan Case);
- 10 • Case U-20878 (NSP 2022-23 EWR Plan Case);
- 11 • Case U-20879 (UPPCO 2022-23 EWR Plan Case);
- 12 • Case U-20880 (UMERC 2022-23 EWR Plan Case);
- 13 • Case U-20881 (DTE Gas 2022-23 EWR Plan Case);
- 14 • Case U-20882 (MGU Gas 2022-23 EWR Plan Case);
- 15 • Case U-20883 (SEMCO Gas 2022-23 EWR Plan Case);
- 16 • Case U-20889 (Consumers Karn Retirement Securitization);
- 17 • Case U-20963 (Consumers Energy Electric Rate Case);
- 18 • Case U-21015 (DTE Securitization Case);
- 19 • Case U-21048 (Consumers Energy 2022 PSCR Plan);
- 20 • Case U-21081 (UMERC 2021 IRP);
- 21 • Case U-21090 (Consumers Energy 2021 IRP);
- 22 • Case U-21189 (Indiana Michigan 2022 IRP);
- 23 • Case U-21193 (DTE Electric 2022 IRP);

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- Case U-21224 (Consumers Energy 2022 Electric Rate Case);
- Case U-21297 (DTE Electric 2023 Rate Case);
- Case U-21377 (IM Renewable Acquisition);
- Case U-21389 (Consumers Energy 2023 Electric Rate Case);
- Case U-21540 (MGU 2024 Gas Rate Case);
- Case U-21555 (UPPCO 2024 Rate Case);
- Case U-21534 (DTE 2024 Electric Rate Case);
- Case U-21585 (Consumers 2024 Electric Rate Case);
- Case U-21654 (EWR Alternative Compliance Plan);
- Case U-21662 (DTE 2024 Renewable Energy Plan Case);
- Case U-21816 (Consumers Energy 2024 Renewable Energy Plan Case);
- Case U-21859 (Consumers Energy Data Center Tariff Case);
- Case U-21813 (UMERC 2025 Renewable Energy Plan Case); and
- Case U-21860 (DTE 2025 Electric Rate Case).

Additionally, I have testified as an expert witness before the Public Utilities Commission of Nevada in Case No. 16-07001 concerning the 2017-2036 integrated resource plan of NV Energy; and before the Missouri Public Service Commission in Case Nos. ER-2016-0179, ER-2016-0285, and ET-2016-0246 concerning residential rate design and electric vehicle (“EV”) policy, revenue requirements, cost of service, and rate design. I testified before the Kentucky Public Service Commission in Case No. 2016-00370 concerning municipal street lighting rates and technologies. I testified before the Massachusetts Department of Public Utilities in Case Nos. DPU 17-05 and DPU 17-13 concerning EV charging infrastructure program design and cost recovery. Before the Rhode Island Public Utilities

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Commission, in Case No. 4780, I testified concerning Advanced Metering Infrastructure and EV charging infrastructure. Before the Delaware Public Service Commission, I testified regarding EV charging infrastructure in Case No. 17-1094. I testified before the Georgia Public Service Commission in Case No. 4822 concerning PURPA avoided cost. I testified before the Colorado Public Utilities Commission in Case Nos. 20A-0204E and 20A-195E concerning cost recovery for EV charging infrastructure. I also testified before the Minnesota Public Utilities Commission in Case No. 22-432 regarding EV charging rate design. I testified before the Public Service Commission of Wisconsin in Certificate of Public Convenience and Necessity Cases Nos. 6630-CE-316 and 6630-CE-317.

I have also testified as an expert witness on behalf of the State of Michigan before the Federal Energy Regulatory Commission ("FERC") in cases relating to the relicensing of hydro-electric generation and have participated in state and federal court cases on behalf of the State of Michigan concerning electricity generation matters, which were settled before trial. I have also filed affidavits in support of filings by the Attorney General of Michigan in docket no. EL25-90-000 and in support of a request for reconsideration and appeal of a Federal Power Act Section 202c Order by the Secretary of Energy.

Q. Are you sponsoring any exhibits?

A. Yes, I am sponsoring the following exhibits:

Exhibit CUB-11: Resume of Douglas B. Jester

Exhibit CUB-12: TEP-Managed vs Overall EV Growth

Exhibit CUB-13: Response to MNSC-CE-0569

Exhibit CUB-14: Response to MNSC-CE-0576

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1 Exhibit CUB-15: Response to MNSC-CE-0578
2 Exhibit CUB-16: Response to MNSC-CE-0583
3 Exhibit CUB-17: Response to MNSC-CE-0570
4 Exhibit CUB-18: Response to MNSC-CE-0582
5 Exhibit CUB-19: Response to MNSC-CE-0577
6 Exhibit CUB-20: Response to MNSC-CE-0579

7 **II. SUMMARY**

8 **Q. What topics are you addressing in your testimony?**

9 A. My testimony will address the following topics regarding Consumers Energy Company's
10 (hereafter "Consumers Energy" or "the Company") Application and supporting testimony
11 in this case:

- 12 • Securitization of distribution system surge spending;
13 • Consumers Energy's internal fleet electrification strategy; and
14 • Implementation of Consumers Energy's Transportation Electrification Plan.

15 **Q. Which Consumers Energy witnesses' testimony do you discuss in your testimony?**

16 A. I am addressing aspects of the testimony of Consumers Energy witnesses Heidi J. Myers,
17 Jennifer M. Partlan, Sara E. Stewart, Jeffrey A. Myrom, and Quintin A. Guinn.

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**III. SECURITIZATION OF DISTRIBUTION SYSTEM SURGE SPENDING [On behalf
of NRDC and CUB]**

Q. Consumers Energy has been increasing, and in this case proposes to further increase, expenditures on its distribution system. Should any of this spending be considered to be a surge in spending rather than a permanent increase in spending levels?

A. Yes. A considerable portion of this spending increase is to shorten line clearing cycles, (after which line clearing expense will be reduced) and to catch up on deferred maintenance investments.

Q. Does Consumers Energy propose a surge in line clearing expenses?

A. Yes. While this is referenced in the testimony of several witnesses, the primary testimony supporting and detailing the proposal is provided by witness Sara E. Stewart.¹ Her Figure 4, reproduced below, shows that the Company is proposing a surge in line clearing with a substantial portion of the planned work addressing backlog miles:

¹ Direct testimony of Sarah E. Stewart, in its entirety.

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FIGURE 4
PLAN FOR LVD BACKLOG MILES ELIMINATION
FULL CIRCUIT CLEARING MILES

Vision Year	Plan Miles	On Cycle Miles	Backlog Miles	Backlog Miles Remaining
Year 1	9,019	5,279	3,740	26,684
Year 2	10,885	6,338	4,547	22,138
Year 3	12,814	6,365	6,449	15,689
Year 4	13,588	6,042	7,546	8,143
Year 5	14,837	6,694	8,143	0

Consumers Energy's projection of LVD line clearing expense is included in witness Stewart's Figure 12, reproduced below:

FIGURE 12
LVD LINE CLEARING RAMP-UP SCHEDULE

Calendar Year	Data Type	O&M Full-Circuit Clearing Miles	O&M Subprogram Clearing Miles	O&M Subprogram Spray Miles	Capital Clearing Miles	O&M Expense (\$M)	Capital Contractor Costs (\$M)	Local Crews	Out-of-State Crews	Total Crews
2020	Actual	3,679	294	238	258	\$46.10	\$5.67	220	0	220
2021	Actual	4,647	238	395	252	\$75.83	\$6.07	299	0	299
2022	Actual	5,653	247	488	221	\$91.02	\$6.71	334	0	334
2023	Actual	5,758	244	443	168	\$97.79	\$5.59	348	0	348
2024	Actual	5,400	244	421	258	\$99.49	\$9.69	347	0	347
2025	Projected	6,108	244	413	325	\$113.20	\$14.01	364	0	364
2026	Projected	7,891	199	405	325	\$152.97	\$14.29	403	53	456
2027	Projected	10,885	149	454	325	\$201.75	\$14.57	420	120	540
2028	Projected	12,814	137	501	325	\$226.28	\$14.87	420	158	578
2029	Projected	13,588	75	491	325	\$230.43	\$15.16	420	158	578
2030	Projected	14,837	75	508	325	\$236.81	\$15.47	420	158	578

She further testifies that the Company projects that the cost of maintaining the 5-year line clearance cycle for the LVD system after this surge will be \$168.525 million per year.²

² Direct testimony of Sara E. Stewart, p. 35, lines 1-6.

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1 **Q. How does Consumers Energy propose to handle its surge in tree-trimming costs?**

2 A. Consumers Energy proposes to defer expense above baseline line clearing expense and
3 securitize the regulatory asset once the balance reaches an appropriate level.³

4 **Q. Do you support the Company's proposal to surge line clearing and to defer, then**
5 **securitize, the surge in line clearing expenses?**

6 A. Yes, I do. The surge in line clearing is the most important step the Company can take to
7 improve its distribution outage performance and is supported by the Liberty Audit and the
8 Commission's decisions in the Company's last rate case. The proposal to defer and
9 securitize surge costs serves to reduce the rate impact of the line clearing surge and to align
10 the timing of cost recovery of the surge expenses with the timing of the resulting
11 improvements in reliability.⁴

12 Consumers Energy identifies the test year surge in line clearing expenses as \$21.4 million,
13 but as my colleague Richard Bunch testifies, the more appropriate amount to defer from
14 the test year is \$72.7 million.

15 **Q. Please explain why a significant portion of the Company's increased distribution**
16 **capital spending is to catch up on deferred maintenance investments.**

17 A. The Liberty Audit identified several types of distribution system assets that should be
18 inspected more frequently.

³ Direct testimony of Heidi J. Myers, p. 9, lines 19-2.1

⁴ A point also espoused in the direct testimony of Patrick D. Daly, p. 36, lines 1-9.

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1 Preventive maintenance can reduce aging and extend the expected life of some assets, such
2 as wooden poles. But for many distribution system assets such as line transformers and
3 conductors, most utilities replace equipment that is failing or that has already failed. Setting
4 aside the benefits of preventive maintenance, periodic inspection and maintenance
5 programs do not significantly affect the rate of failure of distribution system components.
6 Rather, the main value of an inspection is to identify incipient failures and to replace
7 equipment before it fully fails and causes an outage.

8 In steady-state programs, the probability that an incipient failure will be found and the
9 device replaced or repaired before full failure and an outage is approximately⁵ proportional
10 to the ratio of the length of the period of failure incipency to the period between
11 inspections. So, a doubling of the frequency of inspections (or halving of the period
12 between inspections), up to the point when the period between inspections approximates
13 the duration of incipient failure, will in steady state approximately double the number of
14 incipient failures that are detected and addressed. However, each replacement or repair
15 during incipient failure avoids a future replacement or repair that would occur upon
16 complete failure. In steady state, more frequent inspections do not significantly affect the
17 annual total number of repairs or replacements. However, when the period between
18 inspections is shortened, there will be a period of approximately the length of the new
19 inspection cycle when additional replacements or repairs are performed because the more
20 frequent inspections observe more incipient failures that would otherwise have been

⁵ If the period of incipient failure was deterministic and constant, this would not be an approximation. The more heterogenous the period of incipient failure, the more necessary it would be to use a more sophisticated formulation of the probability of replacement or repair before full failure, but even in that case, my qualitative characterization of such programs is broadly valid.

**DIRECT TESTIMONY OF DOUGLAS B. JESTER FOR NSC
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1 replaced or repaired later upon full failure. Thus, as with Consumers Energy's line clearing
2 surge, a shortened period between inspections will produce a surge.

3 The main benefit of more frequent inspections is that a larger share of incipient failures
4 will be repaired before full failure and an outage. In other words, repairs or replacements
5 during an incipient failure will happen sooner than if the repair or replacement is delayed
6 until full failure. Thus, more frequent inspections to repair or replace equipment with
7 incipient failures will shorten the expected service life of the equipment by the difference
8 in time between inspection-based replacement of equipment with an incipient failure and
9 when that equipment would have fully failed. Statistically, that difference will be half the
10 average duration of an incipient failure. Therefore, the effect of more frequent inspections
11 will be a modest increase in baseline frequency of repairs or replacements once a surge is
12 complete. However, the utility costs of individual repairs or replacements will likely
13 decrease when they are done to correct an incipient failure discovered through inspections
14 compared to when they are done in response to outages. The balance of mildly increased
15 repair or replacement frequency and lower cost per repair or replacement event may result
16 in a modest increase or decrease of baseline spending levels, but historic spending levels
17 adjusted for inflation are a reasonable estimate of the post-surge spending levels.

18 In general, shifts in inspection standards that lengthen the period that inspections would
19 consider to be incipient failure would have similar effects to those I described above for
20 increased inspection frequency.

21 Changes in distribution system component standards that increase the expected life of
22 components have somewhat different effects on maintenance and repair costs, producing a

**DIRECT TESTIMONY OF DOUGLAS B. JESTER FOR NSC
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1 cost surge as better but more expensive components are infused into the distribution system
2 to replace existing technology, but then providing reduced frequency of repair or
3 replacement after the improved components are in place. Complete replacement of the
4 incumbent technology with the new technology will take the full life cycle of the incumbent
5 technology components; at the same time, the effect of the new technology will be to
6 gradually reduce the frequency of repair or replacement. The period of surge spending
7 associated with such a process depends on the relative effects of increased component cost
8 and decreased repair frequency and require a different calculation of the surge period. But
9 if the technology change is cost-effective, there will be a period of spending above
10 historical spending levels, followed by a permanent reduction of spending to a level below
11 the historical baseline.

12 We can therefore reasonably approximate surge spending as any spending increase above
13 historic levels, and we can expect a return to historic spending levels after the surge.

14 **Q. Please explain why a portion of increased spending is to repair damage that resulted**
15 **from inadequate preventive maintenance?**

16 A. Some well-executed utility maintenance programs serve to prevent damage that then
17 requires repair or replacement of distribution system components. Sometimes, preventive
18 maintenance is performed directly on the component whose failure rate is reduced. A good
19 example of this is that preservative can be reapplied to wooden poles showing early signs
20 of decay or of depleted preservatives. It is reasonable to assume that some portion of
21 Consumers Energy's pole defects is due to historic low inspection frequency and
22 consequent low application of preventive maintenance practices.

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1 Sometimes, however, damage is avoided by maintenance or repair of something else. A
2 good example of this is tree trimming. Trees do cause immediate outages, and reducing
3 those outages is the primary focus of Consumers Energy's proposed line-clearing surge.
4 However, tree contact causes shorts that can damage nearby electrical equipment. Tree and
5 limb fall creates tension in conductors that can crack pole top insulators. Conductor breaks
6 due to tree damage are typically repaired by splicing conductors at the break point, but
7 splices are weaker than complete conductors and are therefore more susceptible to future
8 line breaks. It is therefore reasonable to assume that some portion of Consumers Energy's
9 distribution system equipment has been damaged and will have shorter life and higher
10 failure rates because of Consumers Energy's historic tree-trimming deficiencies.

11 Thus, the current baseline and surge spending on Consumers Energy's distribution system
12 are at least partly attributable to deficient historical preventive maintenance, especially in
13 tree trimming.

14 **Q. Should surge capital spending on the Company's distribution system other than line**
15 **clearing expenses be securitized?**

16 A. Yes, as with line clearing, deferring and securitizing the surge in capital spending can help
17 align the timing of cost recovery with the timing of reliability benefits. The Commission
18 previously authorized DTE Electric's surge in tree-trimming to be deferred and securitized.
19 In this case, Consumers Energy similarly proposes to defer and securitize a surge in its
20 line-clearing expenses, and I support that proposal. The logic of the Commission's prior
21 approval of DTE Electric's surge and Consumers' surge proposal in this case are similar.
22 Much of the distribution surge spending is needed because of the Company's inadequate

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1 spending on maintenance and inspections in the past. Current customers cannot fairly be
2 asked to pay the costs that were not paid by past customers. Current customers will also
3 not see major benefits from the surge spending, which will largely benefit future customers
4 (and perhaps their future selves).

5 Consumers Energy's past failures to adequately maintain the distribution system, and
6 particularly to spend adequately on current expenses like line clearing, should not enrich
7 current shareholders by inordinately increasing rate base to catch up. Securitization of
8 capital expenditures places surge investments outside Consumers Energy's rate base.

9 Finally, and most importantly, the cost of financing the surge expenditures through
10 securitization bonds will be considerably less than Consumers Energy's authorized
11 weighted cost of capital, helping to mitigate, though not eliminating, the rate impacts of
12 the surge.

13 **Q. What portion of Consumers Energy's proposed distribution system capital**
14 **expenditures should be treated as surge costs?**

15 A. There are a number of categories that might be considered as including surge costs, but the
16 most important and obvious is LVD pole replacements. Witness Jennifer M. Partlan
17 acknowledges that the Company has a backlog of poles needing replacement based on
18 previous inspections.⁶ She further explains that the Company is just beginning a ground
19 line pole inspection program⁷ and expects that approximately 10% of the poles it inspects

⁶ Direct testimony of Jennifer M. Partlan, p. 60, lines 7-16.

⁷ Direct testimony of Jennifer M. Partlan, p. 60, lines 17-18.

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1 will be rejected, leading to a replacement of 12,500 poles.⁸ She provides estimates that test-
2 year capital for pole replacements will be \$127.5 million in contrast to bridge period capital
3 of \$29.711 million. Since the bridge period is 16 months, the annual spending rate in the
4 bridge period is about \$22.28 million and the level of surge spending on pole replacement
5 will be about \$105 million in the test year. Allowing for inflation and other variations in
6 costs, I recommend the Commission deem pole replacement costs that exceed \$25 million
7 in the test year to be surge costs.

8 **Q. What do you recommend the Commission do in this case?**

9 A. First, I recommend the Commission adopt the Company's proposal to defer and securitize
10 its surge in line clearing expenses. I further recommend the Commission adopt the
11 identification of line clearing surge expenses provided in Richard Bunch's testimony.

12 Second, I recommend the Commission order Consumers Energy to defer and propose to
13 securitize its proposed spending for a surge in LVD pole replacements. I estimate that the
14 baseline spending on LVD pole replacements should be \$25 million with all pole
15 replacement costs in excess of that to be considered as surge expenditures.

16 **IV. REVIEW OF COMPANY'S FLEET ELECTRIFICATION STRATEGY [On behalf**
17 **of NRDC, Sierra Club, and CUB]**

18 **Q. How did the Company develop its fleet electrification target?**

19 A. The Company's 30% fleet electrification target was set as a starting point and was not the
20 product of detailed analysis. To evaluate this target, the Company engaged CALSTART to

⁸ Direct testimony of Jennifer M. Parlan, p. 60, lines 20-22 and p. 61, lines 1-7.

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1 conduct a fleet assessment. CALSTART reviewed the Company's vehicle inventory, duty
2 cycles, and operating conditions, and then identified which vehicles could reasonably be
3 replaced with EVs under current market conditions. In other words, the assessment was
4 structured around the 30% goal rather than testing whether a more ambitious target was
5 achievable.

6 **Q. Do you think the Company's 30% electrification target is appropriate?**

7 A. No. Utilities have a uniquely low-friction opportunity to electrify their company's fleet.
8 Unlike most organizations, the Company does not need to rely on a third party to plan or
9 install charging infrastructure—it owns, operates, and manages the very grid resources
10 required to support electrification. This control over both the vehicles and the fueling
11 infrastructure removes barriers that slow other company fleets, making a higher target both
12 reasonable and achievable. Instead, according to Exhibit CUB-18, the Company is backing
13 away from its 30% electrification goal when it should be pursuing a more ambitious target.⁹
14 Light-duty vehicles, which make up the bulk of the Company's fleet, can be electrified
15 readily with models that are already commercially available today. Certain specialized
16 equipment may not yet be easily electrified, but commercially available models exist for
17 most of the vehicle and vehicle types in the Company's fleet, including those that comprise
18 the majority of its vehicles.

19 **Q. What do you recommend regarding the Company's fleet electrification target?**

20 A. The Company should revise its target so that all light-duty vehicle replacements are
21 fulfilled by electric vehicles no later than 2030. This timeline reflects the commercial

⁹ Exhibit CUB-18, Response to MNSC-CE-0582.

**DIRECT TESTIMONY OF DOUGLAS B. JESTER FOR NSC
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availability of light-duty EV models today and the Company's unique ability to manage its own charging infrastructure. A more ambitious target will ensure that the Company leads by example, delivers cost savings to its customers, and captures the significant emissions and public health benefits associated with rapid fleet electrification.

Q. What actions do you recommend the Commission take regarding electrifying the Company's fleet?

A. I recommend that the Commission:

- direct the Company to revise its internal fleet electrification target so that all light-duty vehicle replacements are electric by 2030.

V. REVIEW OF TEP IMPLEMENTATION [On behalf of NRDC, Sierra Club, and CUB]

Q. Please summarize the Company's 2024 Transportation Electrification Plan (TEP).

A. Consumers Energy's TEP¹⁰ seeks to enable one million Evs in its service territory by 2030.

In short:

- **PowerMIDrive Residential** provides \$500 rebates (up to \$1000 for income-qualified customers) for residential L1/L2 charging infrastructure and offers a \$10 per month Smart Charge Incentive for a customer to avoid on-peak charging for up to 12 months.
- **PowerMIDrive Public Charging** provides rebates up to \$7,500 for charging infrastructure in other customer segments, including rebates for multifamily

¹⁰ Consumers Energy, *Consumers Energy Transportation Electrification Plan 2024*, see: <https://mi-psc.my.site.com/sfc/servlet.shepherd/version/download/0688y00000EFQgtAAH>.

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properties, community charging, chargers at overnight destination, and workplace charging. A similar incentive (\$20 per month) is offered to participants at multifamily properties to incentivize off-peak charging.

- **PowerMIFleet** provides rebates for companies installing approved L2 and DCFC chargers for their commercial electric fleets. Rebates are enhanced to support income-qualified fleets with a one-time fund of \$1.6 million. In addition, this program provides third-party fleet assessment services to advise commercial fleets on vehicle electrification. Finally, to support a network of DCFC stations in the Company's service territory to enable long-distance EV travel, this program continues to offer rebates for a series of DCFC sites.
- These programs have shifted nearly all L1 and L2 charging off-peak¹¹
- The Company continues to plan for an influx of DCFC service requests of at least 1 MW by maintaining long-term EV demand forecasts, diversifying equipment supply, and establishing long-term contracts (Exhibit CUB-15).¹²
- The TEP points to a proposal in Case No. U-21585 to provide rebates for battery-integrated DCFC stations to manage fast-charging load and mitigate grid impacts. As summarized in Exhibit CUB-19, the Commission did not approve this proposal, and the Company has not made any new proposals of this kind.¹³

¹¹ See Figure 16 of the TEP:

<https://mi-psc.my.site.com/sfc/servlet.shepherd/version/download/0688y00000EFQgtAAH>.

¹² Exhibit CUB-15, Response to MNSC-CE-0578.

¹³ Exhibit CUB-19, Response to MNSC-CE-0577.

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- The TEP references vehicle-to-everything (“V2X”) and telematics technologies, but the Company currently has no plans to implement them in any managed charging strategy (Exhibit CUB-14).¹⁴

In summary, the TEP aims to enable EV adoption to scale by managing EV load such that it benefits ratepayers and reliability rather than stressing the grid. The Company calculates that the additional margin from electricity sales to Evs, combined with strategic load management, would pay for all the costs of TEP programs with revenue left to spare for rate relief.

Q. What does the Company propose regarding its TEP in the present case?

A. As summarized¹⁵ by Company Witness Myrom, the Company still forecasts EV adoption at roughly 500,000 Evs in the Company’s service territory by 2030, and the Company continues to implement the TEP as approved in earlier cases before the Commission. In the present case, the Company proposes two main enhancements to the TEP:

- 1) **Expand outlet eligibility for rebates:** this proposal would allow NEMA¹⁶ 14-50 outlets to qualify for all L2 rebates and allow NEMA 5-20 outlets to qualify for all long-duration L1 rebates, potentially reducing installation costs and attracting multifamily site hosts who may be interested in a Bring Your Own Cord (BYOC) model.
- 2) **Continuation of DC Fast Charging Rebates:** this proposal includes rebates of up to \$50,000 per 150 kW DCFC port for up to two years after

¹⁴ Exhibit CUB-14, Response to MNSC-CE-0576.

¹⁵ See Direct Testimony of Company Witness Jeffrey A. Myrom.

¹⁶ The National Electric Manufacturers Association.

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1 approval. Rebates of this kind would be prioritized based on community
2 need, alignment with the National Electric Vehicle Infrastructure (“NEVI”)
3 Formula Program’s ‘skeleton network’ standard, and competitive site
4 design and criteria.

5 The Company does not propose increases to its TEP budget in this case, citing headroom
6 in the existing budget and project delays stemming from federal and state funding
7 developments (Exhibit CUB-20).¹⁷

8 **Q. Do you support the proposal to expand outlet eligibility for rebates?**

9 A. Yes. This proposal would reduce costs for multifamily customers and expand charging
10 access without compromising charging quality.

11 **Q. Do you support the proposal to continue DC fast charging rebates under the terms**
12 **presented?**

13 A. No. While I support the continuation of DCFC rebates, I recommend modifications in light
14 of the changed funding landscape. Recent federal legislation has effectively eliminated the
15 30C tax credit, which significantly reduces outside funding support for fast-charging
16 projects. As a result, a higher incentive will be required for many site hosts to justify the
17 investment. Rather than asking the Company to simply increase its rebate level, the
18 Company could instead revise its application process to allow applicants to request a
19 specific rebate amount based on their project circumstances. The Company would then
20 continue to select the most competitive applications, but competitiveness would now be
21 assessed in part by the rebate amount requested. Finally, the Company should extend its

¹⁷ Exhibit CUB-20, Response to MNSC-CE-0579.

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DCFC rebate program to remain available for seven years instead of two to match the original expiration timeline of the 30C tax credit. With the removal of federal support, a longer runway for Company incentives is necessary to adequately support progress toward a reliable, statewide fast-charging network.

Q. How many rebates has the Company issued under the PowerMIDrive program to date?

A. According to Exhibit CUB-13 and Exhibit CUB-16, as of September 8, 2025, the Company has issued the following numbers of rebates under PowerMIDrive:¹⁸

Customer Segment	Rebates Issued to All Customers	Rebates Issued to Income-Qualified Customers
Residential	5,835	Not provided
Multifamily	65	34
Community	81	24
Workplace	181	65
Overnight Destination	136	26
Public DCFC	98	11

Q. Do you have any concerns regarding the Company's pace and distribution of rebates?

A. Yes. The relatively small number of multifamily rebates issued to date is concerning, given the importance of this customer segment for equitable access to EV charging. Multifamily properties face unique barriers, such as shared parking and cost allocation between landlords and tenants, that require more focus than is currently evident from the table above. It is worth noting, however, that the Company has performed relatively well in reaching income-qualified customers with these rebate programs across several segments.

¹⁸ Exhibit CUB-13, Response to MNSC-CE-0569; Exhibit CUB-16, Response to MNSC-CE-0583.

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1 This positive outcome should be acknowledged even while multifamily participation lags.
2 The Company's proposal to expand outlet eligibility to better attract multifamily site hosts
3 is a step in the right direction. Recognizing the need to expand access in this segment, the
4 Company should strengthen its efforts by dedicating resources to targeted outreach and
5 education aimed specifically at multifamily dwellings.

6 **Q. Please summarize how the Company currently manages EV load under its TEP.**

7 A. The Company's reported success in shifting the vast majority of L1 and L2 charging to off-
8 peak hours is achieved primarily¹⁹ through time-of-use rates, customer education, and
9 incentive payments. Many customers are first introduced to the Company's programs
10 through one of the available charger rebates. The PowerMIDrive program, for example,
11 uses AMI data to verify charging patterns and provides participating customers with
12 monthly incentives to avoid on-peak charging. The Company does not employ active
13 managed charging, telematics-based control, or V2X strategies to directly modulate
14 charging load, noting instead that it is "monitoring developments to see how these
15 technologies mature" (Exhibit CUB-14).²⁰

¹⁹ Consumers Energy, *Consumers Energy Transportation Electrification Plan Annual Progress Report 2025*, p. 12 of:
<https://mi-psc.my.site.com/sfc/servlet.shepherd/version/download/068cs00000wdxWAAQ>.

²⁰ Exhibit CUB-14, Response to MNSC-CE-0576.

**DIRECT TESTIMONY OF DOUGLAS B. JESTER FOR NSC
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1 **Q. Do you have any concerns with the Company’s current approach to managing EV**
2 **load?**

3 A. Yes. The Company acknowledges²¹ that “without EV load management programs, most
4 customers will pay no attention to on-peak time periods...when charging.” While the
5 strategies employed to date have successfully shifted most L1 and L2 charging to off-peak
6 hours, these results have largely come from a self-selecting group of early adopters who
7 are willing to engage with their utility and manage charging. According to Exhibit CUB-
8 12, however, the Company’s own forecasts show that overall EV load growth is expected
9 to outpace the growth of TEP-managed EV load between now and 2030.²² This imbalance
10 raises two concerns. First, the Company’s managed charging strategy and the resulting grid
11 and ratepayer benefits may soon be overwhelmed by the scale of unmanaged EV load
12 growth, highlighting an urgent need to scale enrollments in TEP programs. Second, the
13 average future EV driver cannot be assumed to behave like the early adopters who have
14 participated to date. Incentives and education alone may not be enough to influence
15 charging behavior at scale. For this reason, active managed charging and V2X capabilities
16 should be integrated into the TEP now, rather than deferred until 2028²³, to ensure proven
17 tools are in place before unmanaged load growth overwhelms the current passive approach.

²¹ See the Company’s TEP, page 7:

<https://mi-psc.my.site.com/sfc/servlet.shepherd/version/download/0688y00000EFQgtAAH>.

²² Exhibit CUB-12, TEP-Managed vs Overall EV Growth.

²³ The Company indicates that “potential V2X programming” will start in 2028. See page 37 of the TEP:

Canary Media, *Why EV Fast-Charging Stations are Going Big on Batteries*, <https://mi-psc.my.site.com/sfc/servlet.shepherd/version/download/0688y00000EFQgtAAH> (accessed September 30, 2025).

**DIRECT TESTIMONY OF DOUGLAS B. JESTER FOR NSC
CASE NO. U-21870**

1 **Q. Do you have any comments about the Company’s proposal to offer rebates for**
2 **battery-integrated DCFC stations?**

3 A. Yes. Although the Commission did not approve the Company’s proposal in Case No. U-
4 21585, the need for such solutions remains. Unlike residential and workplace charging,
5 DCFC stations are not amenable to traditional managed charging strategies. Drivers expect
6 immediate, high-power charging and will not tolerate delays or curtailments. Battery-
7 integrated DCFC stations offer a practical way to buffer grid impacts, reduce
8 interconnection costs, and improve reliability. This technology is commercially available
9 today²⁴ and is being deployed in other jurisdictions. For these reasons, the Company should
10 revive its proposal, and the Commission should approve it as part of this TEP, so that fast-
11 charging growth can be managed in a way that protects both the grid and ratepayers.

12 **Q. What is your opinion of the fleet assessments provided under the PowerMIFleet**
13 **program?**

14 A. The fleet assessments are reasonable. Exhibit CUB-17 shows that ICF recommended a
15 wide variety of electrification targets tailored to different organizations, which suggests
16 that the assessments account for unique fleet circumstances.²⁵ That said, evaluating
17 electrification potential solely through a total cost of ownership (TCO) lens is too narrow.
18 Fleet vehicles drive more miles than the average passenger vehicle and therefore deliver
19 far greater pollution and greenhouse gas reductions when electrified. While I do not
20 propose overhauling the methodology in this case, it is important to recognize that these

²⁴ <https://www.canarymedia.com/articles/ev-charging/fast-ev-chargers>.

²⁵ Exhibit CUB-17, Response to MNSC-CE-0570.

**DIRECT TESTIMONY OF DOUGLAS B. JESTER FOR NSC
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broader benefits are not captured in a TCO analysis, and they strengthen the policy rationale for supporting fleet electrification through programs like PowerMIFleet.

Q. Do you have any recommendations regarding the PowerMIFleet program?

A. Yes. The program should be extended to include a pilot focused on electrifying school buses with vehicle-to-grid (V2G) capabilities. School buses represent an especially promising application because their operating schedules align well with grid needs and their electrification produces significant public health benefits by reducing students' exposure to diesel exhaust. A V2G-enabled school bus pilot would build on the existing PowerMIFleet structure while demonstrating how fleets can provide both mobility and grid services.

VI. RECOMMENDATIONS

Q. Please summarize your conclusions and recommendations to the Commission.

A. I recommend that the Commission:

- Adopt Consumers Energy's proposal to defer and securitize line-clearing surge expenses.
- Adopt the estimate of line-clearing surge expenses in the test year to which Richard Bunch testifies.
- Also direct Consumers Energy to defer and securitize LVD pole replacement expenses in excess of \$25 million in the test year.
- Direct the Company to revise its internal fleet electrification target so that all light-duty vehicle replacements are electric by 2030.

**DIRECT TESTIMONY OF DOUGLAS B. JESTER FOR NSC
CASE NO. U-21870**

- 1 • Approve the Company's proposal to expand outlet eligibility for charger
2 rebates.
- 3 • Require the Company to revise its fast-charging rebate structure to:
 - 4 ○ Allow applicants to request variable rebate amounts,
 - 5 ○ Prioritize competitive applications that reflect both site quality and
6 rebate efficiency, and
 - 7 ○ Extend rebate availability to seven years to replace the original
8 federal 30D timeline.
- 9 • Direct the Company to develop a proposal in its next rate case to allocate
10 specific funding for targeted education and outreach to multifamily
11 dwellings.
- 12 • Direct the Company to develop a proposal in its next rate case to pilot active
13 managed charging and telematics within its PowerMIDrive program.
- 14 • Direct the Company to reintroduce, in its next rate case, or earlier if
15 practicable, its previous proposal to pilot rebates for battery-integrated DC
16 fast charging sites.
- 17 • Direct the Company to develop a proposal in its next rate case to expand
18 PowerMIFleet with a V2G-enabled electric school bus pilot.

19 **Q. Does that complete your testimony?**

20 **A. Yes, it does.**

1 MR. BZDOK: Thank you. At this time, I would
2 move to bind into the record on behalf of CUB, the revised
3 direct testimony of Richard Bunch, which consists of a
4 cover page, a table of contents, 60 pages of questions and
5 answers, and I would move to admit into evidence Exhibits
6 CUB-21 through CUB-30.

7 JUDGE THOITS: Are there any objections to the
8 admissions of this testimony or these exhibits?

9 Hearing none. The direct testimony of Richard
10 Bunch is bound to the record, and Exhibits CUB-21 through
11 CUB-30 are admitted.

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October 9, 2025

Ms. Lisa Felice
Michigan Public Service Commission
7109 W. Saginaw Hwy.
Lansing, MI 48909

Via E-File

RE: MPSC Case No. U-21870

Dear Ms. Felice:

Attached please find the enclosed documents for filing:

- Proof of Service; and
- Please find the Revised Direct Testimony of Richard Bunch on behalf of CUB, which corrects several internal inconsistencies and typographical errors, plus corrects two erroneous references, marked in redline and described as follows:
 1. **Page 34, Table 4:** Delete ‘to rate base’ from column 4 header, new column heading → ‘Proposed disallowance; 12 months ended 04/30/2027’; O&M disallowances do not impact rate base.
 2. **Page 34, line 12:** Replace \$51.5 with → \$59.5 to reflect typographical error; Conforms to Table 4.
 3. **Page 44, lines 7:8:** Replace ‘Specifically, the Company asserts that its SAIDI, the same model’ with → ‘Further, the Reliability Roadmap model’; corrects sentence fragment.
 4. **Page 47, line 9:** Replace \$127.5 with → \$102.5 to reflect typographical error; Conforms to Table 5.
 5. **Page 51, line 3:** Replace Figure 4 with → Figure 3 to reflect typographical error.
 6. **Page 51, line 9:** Replace 6.4 with → 11.3 to reflect typographical error; Conforms to page 51, line 5.
 7. **Page 52, footnote 65:** Replace 6.4 with → 11.3 to reflect typographical error; Conforms to page 51, line 5.

October 9, 2025

Page 2

8. **Page 57, footnote 73:** Replace footnote with → MPSC Distribution System Reliability Metrics, SAIDI All Weather Michigan Utilities and IEEE Quartile Benchmarks, <https://www.michigan.gov/mpsc/consumer/electricity/distribution-system-reliability-metrics> , Accessed 9/29/2025.
9. **Page 59, line 1:** Replace \$59.9 with → \$59.5 to correct typographical error; Conforms to Table 4.
10. **Page 59, line 21:** Replace ‘six’ with → ‘ten’; Conforms to page 52, Table 9.

Thank you for your assistance in this matter. If you have any questions, please feel free to contact me.

Sincerely,

Tracy Jane Andrews
tjandrews@tropospherelegal.com

CC: Parties to Case No. U-21870

STATE OF MICHIGAN
BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the application of
CONSUMERS ENERGY COMPANY for U-21870
authority to increase its rates for the generation
and distribution of electricity and for other
relief.

REVISED
DIRECT TESTIMONY OF RICHARD J. BUNCH
ON BEHALF OF
CITIZENS UTILITY BOARD OF MICHIGAN

October 9, 2025

~~September 30, 2025~~

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REVISED DIRECT TESTIMONY OF RICHARD J. BUNCH
FOR CUB CASE NO. U-21870

I. INTRODUCTION & QUALIFICATIONS

Q. Please state for the record your name, position, and business address.

A. My name is Richard J. Bunch. I am a lead consultant at 5 Lakes Energy, LLC. My business address is PO Box 869, Northport MI 49670.

I am also Executive Director of Michigan Municipal Association for Utility Issues (MI-MAUI).

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 in my role at 5 Lakes Energy for six years. I have worked since 2015 in positions related to clean energy, primarily on behalf of local governments. A significant portion of that work has included analysis of Michigan Public Service Commission (MPSC or Commission) 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

REVISED DIRECT TESTIMONY OF RICHARD J. BUNCH
FOR CUB CASE NO. U-21870

1 U-20713.

2 In the field of consumer protection, I am president and board chair of the Washington
3 Public Interest Research Group (WashPIRG), an independent, non-partisan, non-profit
4 organization based in Seattle that works to protect consumers and promote good
5 government. I am also an officer of the WashPIRG Foundation, an affiliated research and
6 public education organization. I was Executive Director of WashPIRG from 1989 to 1992
7 and worked on a number of consumer protection issues during that time and in more junior
8 positions prior to that. I also served until 2020 as an officer of the PIRG in Michigan
9 (PIRGIM) Education Foundation, a nonpartisan consumer protection and good government
10 public education and research organization based in Ann Arbor.

11 I am a member of the Commission's Low-Income Energy Policy Board and previously
12 served as a stakeholder co-chair of the Commission's Data Analysis and Regulatory
13 Review working group.

14 My work experience is summarized in my résumé, provided as Exhibit CUB-21.

15 **Q: Please list your training and education relevant to the field of utility regulation.**

16 A. I have participated in the following courses and events.

- 17 • EUCI Outdoor Street Lighting Conference, June 2019
- 18 • EUCI Electric Cost-of-Service - Essential Concepts for a Changing Industry, July 2019
- 19 • MSU-IPU Accounting and Ratemaking course, September 2020
- 20 • EUCI Utility Green Tariffs: A to Z course, November 2020
- 21 • MSU-IPU Advanced Regulatory Accounting and Auditing course, October 2021

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1 • NRRI Regulatory Training Institute, Regulating Public Utility Performance course,
2 2022.

3 • EUCI Advanced Rate Design for Cost Effective Tariffs course, 2024

4 **Q. Have you testified before this Commission or as an expert in any other proceeding?**

5 A. I have previously testified before the Commission in the following cases:

- 6 • Case U-20530 (I&M PSCR Reconciliation case)
- 7 • Case U-20561 (DTE Electric Company Electric General Rate Case)
- 8 • Case U-20697 (Consumers Energy Company Electric General Rate Case)
- 9 • Case U-20836 (DTE Electric general rate case)
- 10 • Case U-20963 (Consumers Energy Company Electric General Rate Case)
- 11 • Case U-21087 (DTE Electric PrePay case)
- 12 • Case U-20836 (DTE Electric Company Electric General Rate Case)
- 13 • Case U-21224 (Consumers Energy Company Electric General Rate Case)
- 14 • Case U-21297 (DTE Electric Company Electric General Rate Case)
- 15 • Case U-21389 (Consumers Energy Company Electric General Rate Case)
- 16 • Case U-21534 (DTE Electric Company Electric General Rate Case)
- 17 • Case U-21860 (DTE Electric Company Electric General Rate Case)

18 I have testified before the Kentucky Public Utilities Commission in rate cases 2020-349
19 and 2020-350, the combined Kentucky Utilities and Louisville Gas & Electric electric and
20 gas rate cases.

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

22 A. Yes, I am sponsoring the following exhibits:

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1	Exhibit CUB-21	Résumé of Richard J. Bunch
2	Exhibit CUB-22	Company Response to U-21870-MNSC-CE-0560 & 0561
3	Exhibit CUB-23	Change in CXCO Historical O&M
4	Exhibit CUB-24	Company Response to U-21870-SA-CE-113 & 114
5	Exhibit CUB-25	Labor Costs Adjustments
6	Exhibit CUB-26	Proposed LVD Pole Replacement Surge
7	Exhibit CUB-27:	SAIDI Benefits Modified U21870-AG-CE-
8		0424_Kelly_ATT_1
9	Exhibit CUB-28	2025-2030 Line Clearing O&M
10	Exhibit CUB-29	Present Value of Each Undergrounding Project
11	Exhibit CUB-30	Sorted Benefits

12 **II. SUMMARY**

13 **Q. What topics are you addressing in your testimony?**

14 A. I am addressing the following topics:

- 15 • General context of this rate case;
- 16 • Inflation and productivity offsets;
- 17 • Reliability Improvement Cost Recovery;
- 18 • Undergrounding; and
- 19 • Storm Cost Recovery Mechanisms.

20 **Q. Which Company witnesses' testimony do you discuss in your testimony?**

21 A. I am addressing the testimony of Company witnesses Blumenstock, Byrom, Daly, Grob,

22 Kelly, Myers, Partlan, Snider, and Stewart.

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1 **III. GENERAL CONTEXT OF THIS RATE CASE**

2 **Q. Please summarize your general understanding of Consumers Energy's requests in**
3 **this rate case**

4 A. Consumers Energy (the Company) is requesting an overall rate increase of \$460,204,000
5 or 9.7%. Most of that increase – \$325,894,000 to be exact – would come from increased
6 residential rates, constituting a 13.3% average increase for residential customers.

7 Many factors contribute to the Company's proposed increase. My 5 Lakes Energy
8 colleague, Douglas Jester, and I address residential rates and reliability, both foundational
9 to the statewide effort to transition to cleaner energy. Our analysis of the Company's rate
10 request reveals that increases in distribution system spending, much of it motivated by the
11 need to improve system reliability, drive most of the proposed rate hike. We support the
12 drive to improve reliability but maintain that this objective must be balanced against rate
13 impacts.

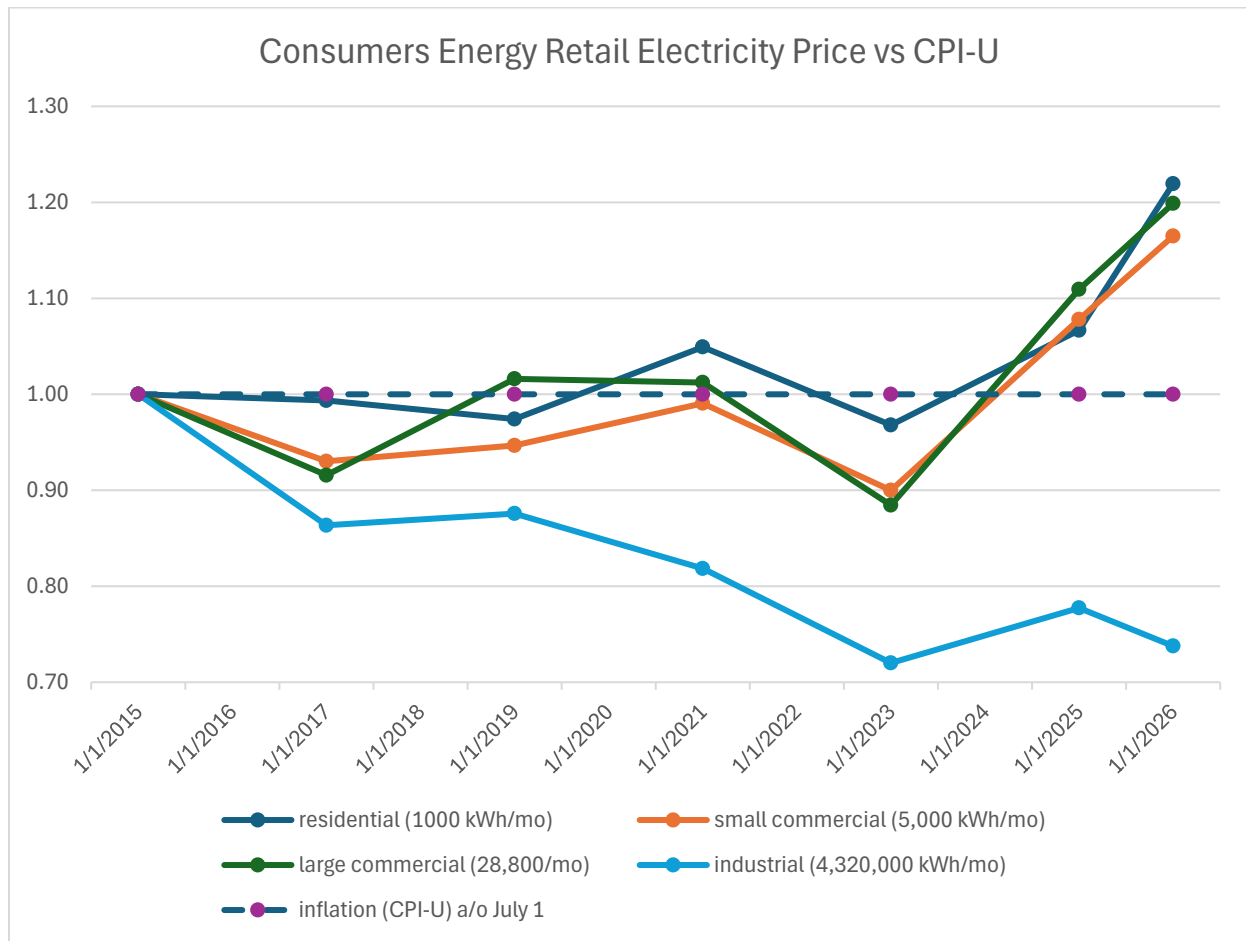
14 **Q. Is Consumers' proposed 13.3% average increase in residential rates reasonable?**

15 A. No. The requested increase is unreasonable in three respects. First, such a significant
16 increase would put unreasonable burdens on household energy budgets, which for too
17 many Consumers customers already consume much more of their household income than
18 the national average. Second, the requested increase greatly exceeds cost inflation. Third,
19 proposed additional investments in reliability are not sufficiently cost-effective to justify
20 the resulting rate increases.

21 Until recently, Consumers' residential retail electricity prices tracked reasonably closely
22 with inflation. (Figure 1)

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1 *Figure 1*



2
3 *Source: MPSC Comparison of Average Rates (<https://www.michigan.gov/mpsc/consumer/electricity>) accessed 8/27/2025*

4 Figure 1 compares Consumers' retail electricity rates to constant 2015 dollars, depicted by
5 the flat dashed line. As of late 2023, residential rates were about the same, in constant
6 dollars, as they had been in 2015. But they had already begun to rise sharply by then, and
7 as of August 2025 they were about 7% higher in constant dollars than they had been in
8 2015. Notably, however, the Company's proposed increase would cause residential rates
9 to be 22% higher, in constant dollars, in 2026 than they were in 2015.

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1 **Q. Why use inflation as a benchmark for rate growth?**

2 A. If rates grow faster than inflation, then energy costs will consume an ever-larger portion of
3 customers' household incomes. Already, Michigan households pay a higher percentage of
4 household income for energy than most other states. In 2023, Michigan ranked 16th worst
5 nationally for total residential energy burden.¹ Rates persistently rising faster than inflation
6 would exacerbate that situation.

7 Inflation does not tell the whole story, though. If Consumers' rates were historically lower
8 than those of comparable utilities, that might contextualize the Company's relatively low
9 reliability performance and justify "catch-up" spending. That is not the case here, however.
10 In 2023, the average US residential customer paid 16 cents per kilowatt-hour.² That same
11 year, Consumers' residential customers were paying 18.8 cents/kWh, or 17.5% higher than
12 the national average.³ An additional rate increase higher than inflation would exacerbate
13 that already large spread.

14 **Q. Is there evidence that rate increases are burdensome to Consumers' residential**
15 **customers?**

16 A. Yes. The number of residential customers significantly in arrears has risen noticeably in
17 recent years. While seasonal variations are significant, as shown in Figure 2, the best-fit

¹ CUB of Michigan 2025 Utility Performance Report, p.36, available at <https://cubofmichigan.org/our-work/reports/>, last checked September 18, 2025

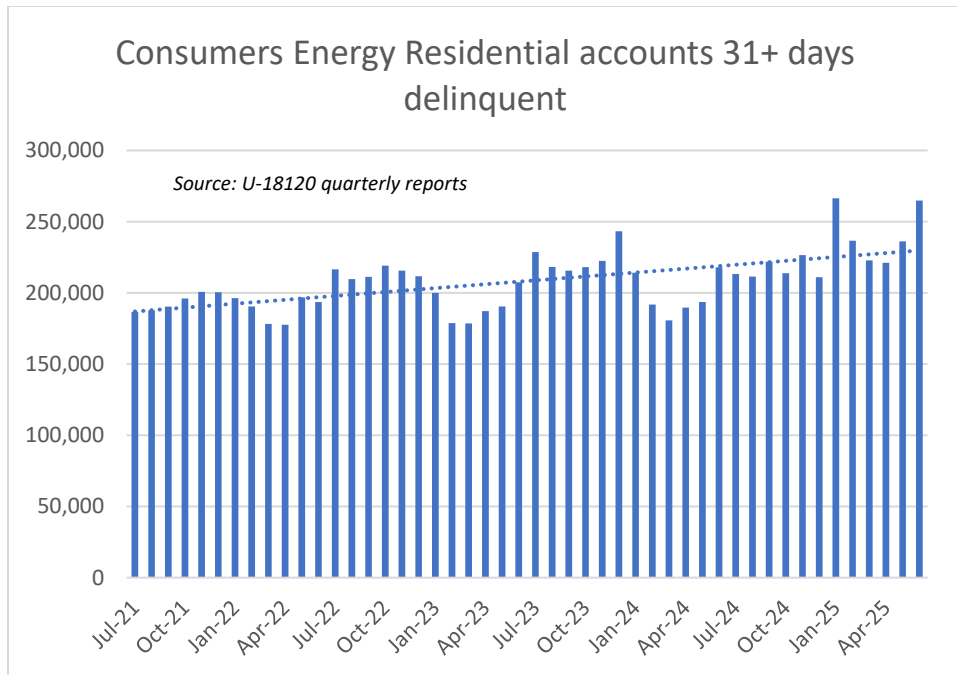
² <https://cubofmichigan.org/reports/utility-performance-report-2025-edition/>, "Household Energy Main" tab, last accessed September 18, 2025.

³ <https://cubofmichigan.org/reports/utility-performance-report-2025-edition/> Energy Costs tab, SAIDI with MEDS data, last accessed 9/18/2025.

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line shows an increase from about 180,000 accounts delinquent for more than 31 days in 2021 to about 230,000 in June of 2025, an almost 28% increase in only four years.

Figure 2



The growth in customers in arrears is roughly proportional to an increase in net write-offs, which the Company ultimately recovers through rates. Net write-offs in 2020 totaled \$10,428,000 and are projected to rise to \$20,274,000 in the projected test year – a doubling rate of seven years at about 10.4% per year.⁴

Q. Should the Commission be satisfied if Consumers' rates were to grow no faster than inflation?

A. No, inflationary electricity price increases are not a satisfactory goal. Rising residential rates, even at about the rate of inflation, still cause increasing financial stress on customers.

⁴ Exhibit A-90 (MJF-4) p. 2.

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In addition, revenue requirements and rates rising in step with inflation indicate ineffective cost containment and productivity efforts by company management. Companies operating in competitive markets cannot pass cost increases directly on to their customers without running the risk of losing business. This cost pressure motivates productivity gains.

Q. Does the need to improve distribution system reliability justify the requested revenue requirement and rate increase?

A. It is fair to expect that Consumers can and should deliver electricity at similar prices and with similar reliability as utilities in nearby states. But the Company's customers are already paying more while getting worse service. The average Consumers customer went 913 minutes without power in 2023.⁵ The US average that year was 342 minutes without power, meaning that the average Consumers customer went about 9-1/2 hours more than, or 2.67 times longer than, the average US customer, while already paying a 17.5% comparative premium for that electricity.⁶

It is unreasonable for the Company's residential customers to experience markedly inferior service quality accompanied by a significant increase in electricity rates. This is contrary to basic performance justification principles. In competitive markets, companies would not expect approval for increased capital while simultaneously presenting substantially poorer performance metrics relative to their industry peers.

⁵ MPSC website Distribution System Reliability Metrics page, SAIDI tab, <https://www.michigan.gov/mpsc/consumer/electricity/distribution-system-reliability-metrics#SAIDI> (accessed September 29, 2025).

⁶ 2025 Utility Performance Report online data, CUB of Michigan, State Electric Reliability tab, SAIDI with MEDs, <https://cubofmichigan.org/reports/utility-performance-report-2025-edition/>. (accessed September 29, 2025).

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1 **Q. Are you suggesting that the Commission should not allow the Company to recover its**
2 **costs?**

3 A. The Commission should allow the Company to recover *reasonable and prudent* costs. It is
4 reasonable to expect the Company to deliver electricity to its customers at rates similar to
5 comparable utilities and with similar reliability. Granting substantial rate increases to help
6 the Company catch up to service reliability benchmarks, when its rates are already high, is
7 unreasonable.

8 **Q. How should the Commission limit rate impacts caused by costs of new activities such**
9 **as the distribution surge spending?**

10 A. A significant portion of Consumers' distribution surge spending is remedial. That is, the
11 Company has fallen behind its peers on distribution system maintenance and investment,
12 causing it to experience worse reliability, and it has a backlog of maintenance to work
13 through. It is not fair to charge today's customers the full cost of investments that should
14 have been made in the past, on top of current investments.

15 Below, I discuss how much surge spending should be attributed to this backlog. My 5 Lakes
16 Energy colleague, witness Douglas Jester, recommends that certain distribution surge
17 expenses should not be recovered as O&M costs or added to rate base but should rather be
18 held as regulatory assets to be considered for future securitization subject to prudence
19 review. In my testimony, I identify specific incremental test-year capital and O&M
20 expenditures undertaken to improve reliability, which witness Jester proposes for
21 regulatory asset treatment and potential securitization.

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1 **Q. What else should the Commission do to reduce the energy burden on Consumers’**
2 **residential electric customers?**

3 **A. In my testimony, I propose two additional measures.**

4 First, I show that the Company projects that the vast majority of benefits from its reliability
5 investments will accrue to non-residential customers and yet its Cost of Service Study
6 allocates a substantial majority of those costs to residential customers. An allocation of
7 these costs more in line with the benefits received would be more equitable and reduce
8 residential rate impacts. I recommend that the Commission direct the Company to review
9 its allocators from a cost-causation standpoint incorporating its analysis of the benefits of
10 these investments, and either propose adjustments or justify the status quo as part of its
11 next rate filing.

12 Second, I oppose the creation of the Company’s proposed Service Restoration Resiliency
13 Fund and Extraordinary Storm Accounting. The Commission has reviewed and rejected
14 essentially similar proposals in the past. There is little new in the Company’s current
15 proposal. These proposals represent attempts to make customers responsible for outage and
16 damage costs resulting largely from the Company’s past improvident distribution system
17 maintenance practices. Aside from this improper assignment of responsibility for costs, the
18 proposals include weak accountability for use of the funds and, by creating a substantial
19 regulatory liability, may result in customers paying costs that may be of benefit only to
20 future ratepayers.

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1 **IV. INFLATION AND PRODUCTIVITY OFFSETS**

2 **Q. Which Company witnesses' testimony do you discuss in this section of your**
3 **testimony?**

4 A. I am addressing the testimony of Company witnesses, Blumenstock, Byrom, Daly, Grob,
5 and Myers.

6 **Q. Please describe how this section of your testimony is organized**

7 A. In section 1, I describe how inflation and productivity impact company costs in general and
8 regulated utilities in particular.

9 In section 2, I summarize the history of this issue in recent Consumers electric dockets
10 including the Commission's relevant orders.

11 In section 3, I describe and critique how the Company has responded to the Commission's
12 orders in the instant filing.

13 In section 4, I recommend what action the Commission should take to address this issue.

14 **Q. Please preview your recommendation.**

15 A. I recommend that the Commission adopt labor and non-labor productivity offsets to
16 inflation factors.

17 **Q. Please briefly describe the basis for your recommendation.**

18 A. The Commission has given the Company ample opportunity to propose a comprehensive,
19 consistent and transparent method for incorporating productivity gains in its cost and
20 expenditure projections. The Company has not done so and argues that the undertaking is
21 unnecessary. I disagree and propose that the Commission adopt a methodology for

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1 incorporating productivity into cost projections that is similar in methodology and basis to
2 that already used for inflation. I propose the application of that method to a specific
3 program and recommend that the Commission require the Company to present future
4 spending proposals in a similar format.

5 **1. Impact of Inflation and Productivity on Costs and Prices**

6 **Q. Can companies operating in competitive markets directly pass inflationary cost**
7 **increases on to their customers by raising prices?**

8 A. No, they cannot. A company cannot raise its prices higher than its competitors' prices
9 without losing market share. Even when all companies face the same inflationary cost
10 pressures, raising prices in unison will reduce overall demand for their products. Either
11 way, raising prices will reduce sales owing to elasticity of demand. To avoid this outcome,
12 companies facing cost pressures innovate, seek efficiencies and cut costs so they can
13 remain price competitive. In this way, productivity gains are a direct response, and offset,
14 to inflationary cost increases.

15 **Q. How can a company mitigate inflationary cost increases?**

16 A. A company is not merely a passive price-taker when unit prices increase, whether owing
17 to inflation or other market forces. A company has various levers to manage inflationary
18 pressures, such as harvesting operational efficiencies, implementing alternative
19 procurement strategies, renegotiating contracts, and managing workforce turnover, which
20 can offset price pressures.

21 First, a company facing increased costs for capital goods and services can extract greater
22 productivity from its existing assets. Rather than buying an additional machine, it can try

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1 to run its existing machines faster or longer, or it can keep older machines in service longer
2 than it had intended by repairing and servicing them rather than replacing them. It can run
3 extra shifts to get round-the-clock production from its physical assets.

4 Second, a company facing increased prices for capital goods and contracts can seek new
5 suppliers through improved procurement processes or can negotiate with existing
6 suppliers.

7 Third, the company can find an alternative production method, modify its specifications,
8 or redesign its product to be less reliant on inputs whose costs are increasing. It can also
9 substitute labor for capital (and vice versa).

10 Fourth, the company can increase labor productivity by revising processes or making
11 capital investments so workers can do their jobs faster or better.

12 In addition, an unregulated company can adjust its output levels to keep its unit input costs
13 down or in anticipation of reduced demand if it raises its prices. This approach may not be
14 fully available to an electric utility like Consumers, although it can influence how much
15 demand is met through effective energy waste reduction (EWR) and demand response
16 programs.

17 Thus, when its input costs rise, a company does not lack potential managerial remedies to
18 avoid passing those increases through to its customers by raising prices.

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1 **Q. With regards to managing cost inflation, how is a regulated utility different from a**
2 **company operating in a competitive market?**

3 A. One important difference between a regulated utility and a company operating in a
4 competitive market is that the utility does not face competitive pressure to keep its prices
5 low. Its customers – mostly - cannot take their business elsewhere.

6 Otherwise, a regulated utility has the same arsenal of managerial responses to inflationary
7 cost increases as companies operating in competitive markets. But it has reduced
8 motivation to deploy that arsenal if it is assumed that it should recover inflationary cost
9 increases by raising rates. Regulatory review should act as a proxy for market forces, and
10 regulatory review of costs and, ultimately, rates, should include a reasonable expectation
11 that the utility demonstrate over time that it is achieving productivity gains similar to those
12 of companies operating in competitive markets.

13 **Q. Should the Commission limit cost growth to inflation offset by productivity on a line-**
14 **item basis?**

15 A. The Commission should focus on limiting increases in *overall* costs and revenue
16 requirement to inflation offset by productivity (“Productivity-Adjusted Inflation” or PAI).
17 It may build up the allowable change in revenue requirement by applying a factor to each
18 line item, but it should not rigidly insist that every program budget grow (or shrink) in
19 lockstep. Per my discussion of management actions above, to realize productivity gains the
20 Company must have managerial discretion to balance cost increases in one area with
21 changes in others. In this way, the Company can fully recover reasonable and prudent cost
22 increases by identifying offsetting productivity measures.

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1 **Q. Do you recommend that the Commission preclude any and all growth in cost and**
2 **revenue requirement in excess of Productivity-Adjusted Inflation?**

3 A. No – there are situations in which increased cost is justified. When sales increase, for
4 example, it should be relatively straightforward for a utility to demonstrate how that
5 increases costs. New statutory or performance requirements may also justify cost increases
6 in excess of productivity-adjusted inflation, but even in those situations the Commission
7 should insist that the Company demonstrate cost-effective responses.

8 **2. History of Inflation and Productivity Issues in Recent Consumers Dockets**

9 **Q. Has the Commission addressed the Company’s use of inflation factors before?**

10 A. Yes. In the Company’s most recent electric rate case, U-21585, the Commission addressed
11 the use of inflation factors in projecting the Company’s O&M expenses. The Company
12 utilized annual inflation factors to reconcile its historical year O&M costs with projected
13 test year estimates. It first escalated historical costs for inflation and then applied “Other
14 Adjustments” to reconcile the inflation-adjusted costs with its test-year projections.⁷

15 MNC argued that the Company’s inflation rates should be reduced by an appropriate
16 productivity factor for labor and non-labor costs, as regulated utilities don’t face the same
17 pressures to improve efficiency as companies in competitive markets, and a productivity
18 factor would simulate that effect.⁸ The Company countered that reducing the inflation rates
19 by a productivity factor would not be reasonable or appropriate because “(i) not all O&M
20 expenses are projected by the Company using inflation; and (ii) productivity gains were

⁷ Case No. U-21585, PFD dated January 27, 2025, p. 474.

⁸ *Id.*

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1 already reflected in the Company's projection of test year O&M expenses where
2 applicable."⁹ The Company noted that many of the Other Adjustments for various line
3 items were reductions, and that the overall test year's projected costs were lower than the
4 historical year's actuals.¹⁰

5 The ALJ agreed with MNC that productivity improvements may offset or partially offset
6 inflationary pressures and questioned whether the 'Other Adjustments' simulated the effect
7 of productivity improvements.¹¹ The ALJ concluded that the Company did not provide
8 sufficient evidence to support the claim that the reduction in O&M costs is attributable to
9 productivity gains and not to other methodological factors, such as the use of a five-year
10 average to calculate certain projected costs.¹² The ALJ "recommend[ed] that the
11 Commission accept [Consumers'] projection in this case but direct Consumers to present
12 more detailed evidence to demonstrate that it is in fact offsetting inflation by productivity
13 in the Company's next rate case."¹³ The Commission adopted the ALJ's
14 recommendation.¹⁴

15 **Q. Has the Commission addressed inflation and productivity in other Consumers Energy**
16 **dockets?**

17 A. Yes, it has. A similar issue arose in the Company's most recent gas rate case, U-21806,
18 where the ALJ recommended that the Commission require the Company to clearly show

⁹ *Id.* at 475.

¹⁰ *Id.*

¹¹ *Id.*

¹² *Id.*

¹³ Case No. U-21585, Order, March 21, 2025, p. 355-56.

¹⁴ *Id.* at 356.

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1 in its next rate case how it offsets inflationary increases with productivity gains. The ALJ
2 also rejected the Company's claim that this process is too burdensome, noting that the
3 Company already considers productivity or other reductions in its cost estimates, and the
4 directive merely asks the Company to more transparently document those practices.¹⁵ The
5 Commission issued its final order in that case on the date this testimony was filed.

6 **3. Summary and Discussion of Consumers' Proposals Regarding Inflation and**
7 **Productivity in This Case**

8 **Q. What rate of inflation is the Company proposing to utilize through the test year?**

9 A. Company witness Daly proposes inflation factors of 2.1%, 2.4% and 2.4% for years 2025,
10 2026, and 2027, respectively. The 2027 factor is pro-rated to 0.8% for the 4-month period
11 ending April 30, 2027.¹⁶

12 **Q. How is the Company applying these inflation rates to arrive at test-year cost**
13 **projections in this case?**

14 A. Inconsistently. Sometimes Company witnesses explicitly apply inflation rates, and
15 sometimes they don't. Company witnesses rely on a mix of methods to reach their final
16 projection figures, which often obscures the underlying factors driving their increasing
17 costs. In many instances, budget line items with no explicit inflation rate applied also
18 include the impact of inflation in their cost projections.

¹⁵ Case No. U-21806, PFD dated August 14, 2025, p. 417.

¹⁶ Direct Testimony of Patrick D. Daly, p.14, 10:11.

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1 **Q. Are there examples where the Company explicitly demonstrates applying inflation**
2 **factors in its cost projections?**

3 A. Yes. Witness Daly compiles inflation increases to O&M costs across all work groups in
4 Exhibit A-13 (PDD-42), Sch. C-5.1, lines (d) through (f), with Other Adjustments reflected
5 in (g). However, the adjustments shown do not always align with the actual inflation
6 assumptions used by sponsoring witnesses.

7 For example, in Exhibit A-97 (KKG-1) p. 2, witness Grob seemingly applies witness
8 Daly's sponsored inflation rate to capture inflation-related changes to the Company's
9 Defined Company Contribution Plan (DCCP) and Savings Plan costs (line items 13 and 14
10 of Exhibit A-13, Schedule 5.1). However, witness Grob's direct testimony states that the
11 Company is using a merit salary factor of 3.2% for 2024 through the 12 months ending
12 April 30, 2027, to arrive at the projected test-year costs for the Company's DCCP¹⁷ and
13 Savings Plan¹⁸ costs. This merit salary factor exceeds the inflation factor recommended by
14 witness Daly. Further clarification through discovery reveals that the portion of merit
15 increases in excess of inflation is captured in the 'Other Adjustment' in column (i).¹⁹

16 In another instance, witness Byrom testifies that Exhibit A-53 (JRB-2), page 4, which
17 provides information for lines 9 and 10 of Exhibit A-13 (PDD-42), Schedule C-5.1, is a
18 hypothetical illustration of projected Customer Experience and Operations O&M expenses
19 based on a hypothetical inflation factor.²⁰ She uses a zero-based accounting method to

¹⁷ Direct Testimony of Kendra K. Grob, p.16, 8:10.

¹⁸ *Id.* at 17, 23 to 18, 1.

¹⁹ Exhibit CUB-22, Company Response to U21870-MNSC-CE-0560 & 0561.

²⁰ Direct Testimony of Jessica R. Byrom, p. 4, 2:16.

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1 arrive at her projections, and column (g), Other Adjustments, captures any difference
2 between her projections and the Company-sponsored inflation-adjusted numbers.²¹
3 Projected costs for Customer Experience & Operations are expected to increase by 5.1%
4 annually in the bridge period and the projected test year, compared to a decline of 7.5%
5 annually between 2019 and 2024.²² Witness Byrom notes increases in labor and contractor
6 costs as one of the reasons for cost increases across multiple workstreams under Customer
7 Experience and Operations; however, it is unclear whether these are driven by unit cost
8 increases, necessary resource increases or both, and at what rates, and if the Company-
9 sponsored inflation correctly captures it.

10 These examples show that even where Company witnesses seemingly explicitly apply the
11 Company-sponsored inflation factor, the actual inflationary effects are only partially
12 captured in the inflation adjustments shown in columns (d) through (f) and the rest flow
13 into Other Adjustments.

14 **Q. Are there examples where the impact of inflation is embedded in cost projections**
15 **without being identified as an explicit factor?**

16 Yes. Company witness Stewart sponsors the total O&M costs for Forestry Operations in
17 line 2 of Exhibit A-13 (PDD-42), Schedule C-5.1, with no amounts identified for inflation
18 adjustments. However, in her direct testimony, witness Stewart states that “[t]he
19 Company’s internal labor expenses for Forestry Operations shown in Figure 14 and Exhibit
20 A-175 (SES-6) are a combination of current staffing, anticipated retirements, replacement

²¹ *Id.*

²² Exhibit CUB-23, Change in CXCO Historical O&M.

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1 and new hiring, merit increases, and contracted planning resources,”²³ which includes the
2 impact of labor inflation, even though no corresponding merit and inflation increases are
3 reflected.

4 **Q. Does the Company’s presentation accurately reflect how inflation is impacting its cost**
5 **projections?**

6 A. No. For O&M expenses, more than half of the line items in Exhibit A-13 (PDD-42),
7 Schedule C-5.1, do not incorporate the Company-sponsored inflation numbers for cost
8 projections. Instead, many of their ‘actual’ inflation effects are embedded in the ‘Other
9 Adjustments.’²⁴

10 Inflation-adjusted numbers created and presented in this manner are not transparent
11 reflections of the labor and material cost drivers that the Company is facing. The
12 Company’s treatment of inflation in cost projections is not comprehensive, consistent, or
13 clear.

14 Witness Daly does not provide a similar breakdown of inflation adjustments for capitalized
15 costs summarized in Exhibit A-12 (PDD-35), Schedule B-5. However, similar to O&M
16 expenses, each of the sponsoring witnesses’ testimony and exhibits provides more details
17 on the inflation adjustments applied, either directly or embedded in cost projections.

²³ Direct Testimony of Sara E. Stewart, p. 37, 15:17.

²⁴ Exhibit CUB-24, Company Response to U21870-SA-CE-113 & 114.

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1 **Q. How are the Company's costs changing as compared to inflation in this case?**

2 A. The Company's test-year O&M expenses are projected to increase by 21.4% from 2024
3 historical actual expenses. The Company's test-year capital expenditure is projected to
4 increase by 62.8% from 2024 historical actuals. (**Table 1**)

5 ***Table 1: Comparing growth in Consumers' electric costs vs inflation***

	Actual; 12 Mo Ended 12/31/2024	Projected; 12 Mo Ended 4/30/2027	% change
O&M	663,157	804,953	21.4%
Labor	250,644	277,065	
Non-labor	412,513	527,888	
Capex	1,175,022	1,913,465	62.8%
Labor	175,770	287,904	
Non-labor	999,252	1,625,561	
Total labor (O&M and capitalized)	426,413	564,969	32.5%
Total non-labor (O&M and capitalized)	1,411,765	2,153,448	52.5%
Compounded Company- sponsored inflation from 12/31/2024 thru 04/30/2027			5.4%

7 Breaking these down by labor versus non-labor, the Company's test-year O&M and
8 capitalized labor costs are projected to increase by 32.5% compared to the historical year
9 2024 amounts. I calculated this amount by adding labor-cost details from sponsoring
10 witnesses to witness Daly's summary O&M and Capital expense worksheets.²⁵

11 The Company's test-year O&M and capitalized non-labor costs are projected to increase
12 by 52.5% compared to the historical test year 2024 amounts. This total includes all line

²⁵ Exhibit CUB-25, Labor Costs Adjustments.

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1 items not classified as labor or union labor in the Company's budget line items. It does
2 include costs corresponding to line-item contractor, as those are not specifically outlined
3 as labor-only costs by the Company. I calculated this amount by adding non-labor cost
4 details from sponsoring witnesses to witness Daly's summary O&M and Capital expense
5 worksheets.

6 The Company's projected compounded inflation rate during the same period is 5.39%,
7 significantly lower than the O&M and capital expense increases the Company is projecting.
8 The bulk of the increase in costs is captured in the Other Adjustments columns of the
9 Company's exhibits.

10 In short, the Company's projected costs are increasing much faster than inflation.

11 **Q. How did the Company respond to the Commission's order in case U-21585 regarding**
12 **inflation and productivity?**

13 A. Company witness Myers addresses the issue in her testimony, stating that there are
14 complexities in presenting granular, standalone evidence that definitively attributes cost
15 containment to productivity gains.²⁶ She further states that the absence of such detail should
16 not be interpreted as a lack of effort or effectiveness in managing inflationary impacts
17 through productivity.²⁷

18 While it may be a challenging exercise to implement, it is the Company's burden to present
19 evidence showing *how* it is incorporating cost containment and productivity into its
20 budgeting process rather than simply assuring the Commission that it is doing so.

²⁶ Direct Testimony of Heidi J. Myers, p. 29, 14:16.

²⁷ *Id.* at 29, 20:21.

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1 **Q. Does the Company provide examples of how it claims to be increasing productivity?**

2 A. Yes, witness Myers provides several examples from other Company witnesses, illustrating
3 how cost projection is more complex than simply applying an inflation factor to historical
4 costs. The statements suggest potential productivity improvements passing through to test-
5 year cost projections, but most do not withstand scrutiny:

6 • **Company claim:** “Ms. Stewart states that all contractor rates are contractually
7 limited through mid-2029 to an annual adjustment of a minimum of 0.0% per year
8 up to a maximum of 2.5% per year based on the Producer Price Indices WPUFD4
9 and WPU443.”²⁸

10 **Response:** Productivity, simply put, is output per unit of input. Contractor
11 productivity, then, is output per contract dollar spent. Because witness Stewart does
12 not address whether contractor output is rising faster than contract rate caps, this
13 example tells us nothing about contractor productivity.

14 • **Company claim:** “Company witness Byrom explains that Customer Experience &
15 Operations’ projected expenses are developed using zero-based budgeting. This
16 means that all expenses must be justified for a new period or year, starting from
17 zero, versus starting with the previous budget and adjusting it as needed. She also
18 describes initiatives that have resulted in reduced costs for customers.”²⁹

19 **Response:** Zero-based budgeting is simply an alternative budgeting method and
20 has no specific bearing on how the Company manages inflation and offsets it by

²⁸ *Id.* at 30, 6:9.

²⁹ *Id.* at 30, 19:23.

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1 harvesting productivity improvements. Furthermore, as previously mentioned,
2 witness Byrom provides no details on how the Company plans to manage labor
3 rates, contractor costs, or postage rates and become more cost-efficient. It is unclear
4 what programs witness Myers is referring to in the latter half of the statement.

- 5 • **Company claim:** “Company witness Foster describes how Adjusted Corporate
6 Services O&M expense was calculated and describes a reduction to projected test
7 year O&M due to insurance distributions.”³⁰

8 **Response:** The reduction in insurance distributions in the projected test year is due
9 to the replacement of actual insurance distributions received in 2024 with a 5-year
10 historical average.³¹ A change in cost projection method is not the same as a real
11 change in costs, and a change in costs is not the same as a change in productivity.

- 12 • **Company claim:** “Company witness Blumenstock describes how Generation
13 O&M is projected and discusses efficiencies that have limited cost increases in the
14 projected test year.”³²

15 **Response:** In his testimony, witness Blumenstock states that, “Total O&M expense
16 for the years 2024 through the projected test year demonstrates average annual
17 decreases of approximately 9.0%. As discussed later in this direct testimony, this
18 average annual decrease primarily reflects a change in the mix of the Company’s
19 owned generating assets, including the movement of renewable energy resources

³⁰ *Id.* at.31, 3:5.

³¹ Direct Testimony of Matthew J. Foster, p.7, 7:11.

³² Myers Direct, p.31, 1:2.

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1 to the Company's renewable energy plans.”³³ However, he provides no evidence
2 clarifying the relative contribution from each factor, leaving it unclear whether the
3 decrease reflects real operational efficiency or a shift of costs from the rate case to
4 the REP . He also highlights two waste reduction projections, which reduce total
5 O&M expenses by \$490,000 in the projected test year. This is perhaps the most
6 relevant example presented by the Company of how it is identifying opportunities
7 to reduce overall costs.³⁴

8 The Company conflates quantifying productivity improvements with contractual labor cost
9 caps, alternative budgeting methods, and cost reductions resulting from methodological or
10 reporting changes. The Company's anecdotes fail to demonstrate how it is harvesting
11 productivity improvements to offset inflationary pressures, and it provides no
12 comprehensive approach to the undertaking.

13 **Q. Has the Company, per the Commission's order in Case No. U-21585, presented “more**
14 **detailed evidence to demonstrate that it is in fact offsetting inflation by productivity**
15 **in the Company's next rate case?”³⁵**

16 **A.** No. The Company has essentially resuscitated the same arguments it presented in U-21585,
17 which the Commission found lacking then. As quoted above, in U-21585, the Company
18 stated that: “(i) not all O&M expenses are projected by the Company using inflation; and
19 (ii) productivity gains were already reflected in the Company's projection of test year

³³ Direct Testimony of Richard T. Blumenstock, p.103, 11:15.

³⁴ *Id.* at 100, 1:19.

³⁵ Case No. U-21585, PFD dated January 27, 2025, p. 476.

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O&M expenses where applicable.”³⁶ These assertions are indistinguishable from the arguments the Company makes in this case, albeit at greater length, including examples that largely fail to hold up under scrutiny. While the examples offered by the Company provide more detail per the Commission’s previous order, those details are not relevant or responsive to the Commission’s previous order.

4. Recommendations to the Commission Regarding Inflation and Productivity

Q. Should the Commission accept Consumers’ assurances that it is incorporating productivity gains?

A. No. If the Company were delivering more electricity with greater reliability (outputs) at a faster rate than its revenue requirement (inputs) were growing, that would be a high-level indicator of productivity gains. Instead, the Company proposes to deliver a little bit more electricity slightly more reliably by increasing capital spending almost 63%, a tremendous decline in capital productivity, and O&M spending by more than 21%. The Company may be realizing some productivity gains but the overall financial picture does not suggest systematic and significant improvements.

To address this issue going forward, the Commission should constrain the Company to Productivity-adjusted Inflation (PAI) increases in O&M and capital expenditures and require it to justify any excursions from these limits (“Other Adjustments”) in terms of changes in sales, legal, or performance requirements.

³⁶ *Id.* at 474.

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1 **Q. Please explain how the Commission should utilize PAI to benchmark the Company's**
2 **costs.**

3 A. If the Company responds to cost pressures as effectively as companies in competitive
4 markets must, then it should be able to recover reasonable costs with rates that increase at
5 the Productivity-adjusted Inflation (PAI) rate:

6
$$\text{PAI} = \text{Projected Inflation Rate} - \text{Projected Productivity Gain}$$

7 This equation recognizes that the Company is subject to inflationary cost pressures, but if
8 it can improve labor and capital productivity at the same rate as other companies, it can
9 offset a substantial amount of the inflationary increases and mitigate the impact of
10 increasing costs on rates.

11 The Commission should hold expenditures related to ongoing, or baseline, activities to
12 productivity-adjusted growth no greater than the PAI factor. The Commission may allow
13 additional expenditures driven by changes in sales, legal or performance requirements, or
14 other case-by-case supported adjustments, but the default should be to hold baseline
15 historic expenditures to grow no faster than PAI.

16 Applying PAI ensures that utility rates would rise only to the extent that cost increases are
17 not offset by improved asset utilization, better procurement practices, workforce
18 optimization, or other operational efficiencies. It would promote cost discipline, align
19 incentives with performance, and mirror how prices are constrained in unregulated sectors
20 of the economy.

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1 **Q. Should the Company's costs never exceed PAI growth rates?**

2 A. The PAI factor would function as a disciplining benchmark for the Company's baseline
3 costs, which should reasonably grow at a PAI rate before adjusting for other dynamics,
4 such as changes in sales, new performance requirements (e.g., reliability surge) or legal
5 requirements. When the Company presents evidence supporting that the future is likely to
6 look different than the past, that demonstration may justify "Other Adjustments." These
7 adjustments, too, are subject to prudence review, and later in my testimony, I address
8 several proposed incremental costs that are not justified.

9 **Q. Should the Commission apply these productivity offsets only to the line-items where**
10 **the Company is explicitly using an inflation factor to arrive at projected test-year**
11 **estimates?**

12 A. No, as previously discussed, the Company's presentation of inflation adjustments is
13 inconsistent, and many cost categories have inflation effects rolled into 'Other
14 Adjustments.' Exempting these line items from the PAI cap would allow the Company to
15 pass along cost increases without demonstrating offsetting efficiency improvements. The
16 PAI factor should be applied consistently across all programs.

17 **Q. Should the Commission require the Company to apply a PAI factor to both O&M**
18 **costs and capital expenditures?**

19 A. Yes. The principles of operational efficiency, cost containment, and accountability should
20 apply to all costs irrespective of whether they are incurred for O&M expenses or capital
21 expenditures. Both O&M and capital expenditures include costs related to ongoing,
22 baseline activities that are subject to inflationary pressures. The Company has access to the
23 same levers – improved asset utilization, better procurement practices, workforce

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1 optimization, and technological improvements – to manage and control its capital costs as
2 its O&M expenses. While the same principles apply in the context of capital expenditures,
3 I recommend the Commission begin here with O&M expenditures.

4 **Q. Should the Commission require the Company to use the same PAI factor for both**
5 **labor and non-labor costs?**

6 A. No, I recommend that the Commission apply different productivity factors to labor and
7 non-labor costs. I recommend the Commission require the Company to apply those factors
8 to whatever inflation factor(s) it approves in this case. I do not make any recommendation
9 in this testimony as to the appropriateness of the Company's proposed inflation factors,
10 other than that they should be adjusted for productivity.

11 Going forward, in the same way that the Commission allows the Company to propose
12 inflation factors, it should allow the Company to propose the productivity factors that best
13 correspond to its cost structures.

14 **Q. The Company has previously rejected this approach, calling it overly simplistic.³⁷ Is**
15 **this method too simplistic?**

16 A. No. As previously noted, in the Company's last electric rate case, U-21585, the
17 Commission issued the Company a clear directive to provide evidence demonstrating how
18 it offsets productivity improvements to mitigate the impact of inflation on costs in its next
19 rate case – i.e., this case.³⁸ The Company's position is that productivity gains are embedded
20 throughout its cost projections in various ways, but the examples it gives are not on point.

³⁷ Case No. U-21806, PFD, p. 412.

³⁸ Case No. U-21585, Order, March 21, 2025, p. 356.

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1 By contrast, my proposal provides a straightforward, transparent, and less burdensome
2 alternative. Furthermore, my recommendation is no more “simplistic” than applying an
3 across-the-board inflation factor, which is a well-established practice. Both inflation and
4 productivity factors rely on thoroughly researched, empirical data collected and reported
5 by federal government agencies.

6 **Q. How should the Commission apply the PAI factor in this case?**

7 A. While the explicit use of a formulaic historical-plus-PAI factor for ongoing, baseline costs
8 may not have been formalized in prior cases, the underlying premise that the Company can
9 offset inflationary pressures through productivity improvements and should provide
10 evidence for how it is incorporating productivity in its cost projections has been accepted
11 in previous proceedings.³⁹

12 For O&M costs, I recommend the Commission apply this methodology to all proposed
13 O&M expenses and disallow excess costs unless they are driven by sales growth or specific
14 performance or legal requirements, such as the costs associated with the Company’s Line
15 Clearing surge. Applying a PAI factor to all O&M costs is consistent and compatible with
16 the development of baseline cost projections developed by escalating historical actuals
17 using inflation.

18 For capital expenditures, I am not making any recommendation in this case in the interest
19 of gradualism and to allow the Company to become more conversant in the methodology.

³⁹ *Id.* at 355.

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1 **Q. What productivity factor should be applied to labor costs in this case?**

2 A. I recommend that the Commission limit O&M labor to 2024 historical levels plus
3 compounded Labor PAI. To calculate Labor PAI, I recommend utilizing the Bureau of
4 Labor Statistics labor productivity figures for Michigan's private, non-farm sector, the
5 most narrowly tailored productivity factor reasonably descriptive of the Company's labor
6 market. The compounded annual change in labor productivity in Michigan from 2014-2024
7 was 1.34%. This results in a Labor PAI rate of 0.76%, 1.06%, and 1.06% in 2025, 2026,
8 and 2027, respectively. (see Table 2 below) These numbers were calculated by subtracting
9 the labor productivity in Michigan from 2014 to 2024 from the Company-sponsored
10 inflation rates.

11 *Table 2: Labor Productivity-adjusted inflation calculations*

Labor inflation factor	2025	2026	2027
Annual merit increase	2.1%	2.40%	2.40%
Number of months in the period	12	12	4
Pro-rated Company projected inflation	2.1%	2.4%	0.8%
Labor Productivity factor	1.34%	1.34%	1.34%
Pro-rated factor	1.34%	1.34%	0.45%
CUB Productivity-adjusted Inflation (PAI-labor)	0.76%	1.06%	0.35%

12 **Q. What productivity factor should be applied to non-labor costs in this case?**

13 A. For non-labor O&M costs, I recommend that the Commission limit projected costs to 2024
14 historical levels plus non-labor Total Factor-PAI. To calculate the non-labor Total Factor-
15 PAI, I recommend utilizing the Bureau of Labor Statistics Total Factor Productivity (TFP)
16 factor for the US private, non-farm business sector. TFP is a measure of economic
17 performance that compares the amount of goods and services produced (output) to the
18 amount of combined inputs used to produce those goods and services. The compounded

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annual change in TFP from 2014-2024 was 0.81%. Applying this average factor to the Company's projected inflation factors derives a non-labor Total Factor-PAI rate of 1.29%, 1.59%, and 1.59% in 2025, 2026, and 2027, respectively. (Table 3).

Table 3: Non-labor Total Factor Productivity-adjusted Inflation

Non-Labor inflation factor	2025	2026	2027
Annual inflation rates per WP-PDD-37	2.1%	2.40%	2.40%
Number of months in the period	12	12	4
Pro-rated Company projected inflation	2.1%	2.4%	0.8%
Non-labor Productivity factor	0.8%	0.8%	0.8%
Pro-rated factor	0.8%	0.8%	0.3%
CUB Productivity-adjusted Inflation (PAI-non-labor)	1.29%	1.59%	0.53%

Q. Have you prepared recommendations for programmatic O&M budgets by applying the methods you describe above?

A. Yes, I have. For O&M expenses, in this case, I recommend that the Commission allow the Company to recover costs that meet the target of historical actuals plus compounded PAI. In the next section of my testimony, I also recommend approving \$72.7 million in additional expenses for the Forestry program that primarily covers costs related to the ramp-up of its LVD and HVD Line Clearing work; witness Jester proposes securitizing these costs. Table 4 shows my program-specific recommendations for test-year O&M expenditures.

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1 **Table 4: CUB Proposed PAI adjustments to test-year O&M projections**

Description	Company Projected; 12 Months Ended 4/30/2027	CUB proposals		
		Proposed historical plus PAI target; 12 months ended 4/30/2027	Proposed disallowance ~~to rate base;~~ 12 months ended 4/30/2027	Proposed securitization \$s for surge expenditures; 12 months ended 4/30/2027
Electric Division - Electric & Common	300,994	253,341	(47,653)	-
Forestry	186,684	113,977	(72,707)	72,707
Generation	103,732	131,920	28,187	-
Operations Support	13,600	15,016	1,416	-
Information Technology Operations	55,297	43,460	(11,837)	-
Information Technology Investments	24,789	8,077	(16,712)	-
Information Technology - Security Operations	11,362	9,548	(1,814)	-
Information Technology - Security Investments	1,513	722	(791)	-
Customer Interactions	23,454	21,476	(1,978)	-
Billing & Payment	11,505	10,495	(1,010)	-
Demand Response	34,630	32,225	(2,405)	-
Defined Company Contribution Plan	16,507	15,097	(1,410)	-
401(k) Employees' Savings Plan	12,731	11,645	(1,086)	-
Active Health Care/Life Insurance/LTD	33,385	29,725	(3,660)	-
Other Benefits	2,780	2,679	(101)	-
Corporate Services	36,968	38,363	1,395	-
Incentive Compensation	2,211	2,150	(61)	-
			(132,226)	72,707

2
3 These recommendations reflect the simple reality that hard choices must be made if rates
4 are not to rise unreasonably. Improvements to reliability are an overriding priority,
5 endorsed by the Commission per the Liberty distribution audit, and incurring additional
6 O&M expenditures that do not directly impact reliability cannot, for now, be a priority.
7 Other O&M costs should be limited to increases determined by Productivity-Adjusted
8 Inflation to avoid any additional impact on rates.

9 **Q. Please summarize your conclusions and recommendations for this section to the**
10 **Commission.**

11 A. For this case, I recommend the Commission use the PAI-adjusted cost approach to limit
12 growth in O&M spending, by completely disallowing ~~\$51.5~~ **\$59.5** million in proposed
13 O&M costs. The Commission should approve forestry surge costs in the additional
amount of

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1 \$72.7 million but, per witness Jester's recommendation, direct the Company to treat those
2 costs as a regulatory asset for potential future securitization.

3 For future cases, I recommend that the Commission direct the Company to present both
4 O&M and capital test-year cost baseline projections calculated as historical cost adjusted
5 for PAI. It should be assumed that the Company can reasonably recover its costs including
6 inflation if it is as industrious as other companies must be in pursuing productivity
7 improvements. The Company may present "Other adjustments" in addition to these
8 baseline amounts but should demonstrate why they are necessary owing to changes in sales,
9 new statutory requirements, or new performance requirements; however, "Other
10 adjustments" should not (implicitly or explicitly) embed inflation.

11 **V. RELIABILITY IMPROVEMENT COST RECOVERY**

12 **Q. Which Company witnesses' testimony do you discuss in this section of your**
13 **testimony?**

14 **A. I address the testimonies of witnesses Kelly, Partlan, and Stewart.**

15 **Q. Please summarize the recommendations you will make here.**

16 **A. I recommend that the Commission approve surge spending in certain reliability programs**
17 **identified as priorities in reports by the Liberty Consulting Group summarizing its audit of**
18 **Consumers' distribution system (Liberty Audit), which the Commission adopted in Case**
19 **No. U-21305. The Company should recover these costs, but in such a way as to minimize**
20 **the rate impact of remedial work on today's customers and to recognize that the Company**
21 **bears some responsibility for the financial and service-quality impacts of catching up on**

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1 backlogged work. In his testimony, witness Jester recommends treatment of these costs as
2 regulatory assets for potential future securitization.

3 **Q. Why is it necessary to minimize the rate impact of remedial work on today's**
4 **customers?**

5 A. All told, the Company's proposed costs and allocation would result in residential rates
6 increasing by over 13%. As I established above, a growing number of customers are
7 already struggling, the Company's rates are already high and have recently risen faster than
8 inflation. To prevent further unreasonable rate increases, hard choices must be made to
9 invest only in reliability programs that yield the greatest improvements per dollar spent.
10 Additionally, the Commission should take steps to ensure that reliability costs are allocated
11 equitably among rate classes and that the way those costs are recovered is equitable.

12 **Q. Which reliability investments do you recommend the Commission approve for surge**
13 **spending?**

14 A. The Liberty Audit identified backlogs in tree trimming/vegetation maintenance and pole
15 replacements and found that surge spending in both these areas would be especially cost-
16 effective. I recommend that the Commission approve these surge costs and hold other
17 reliability investments at PAI-adjusted current levels. Focusing on the backlogged tasks
18 first will make it easier to determine what additional reliability actions may be needed next,
19 after the proverbial dust settles. Implementing everything at once would also be very
20 expensive, as reflected in the Company's proposed revenue requirement.

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1 **Q. Please summarize your concern about equitable recovery of surge costs.**

2 A. Today's customers should not have to bear the full financial burden of catching up to
3 deferred (backlog or surge) maintenance as part of the Company's effort to improve
4 reliability. Substantial costs should have been incurred in the past, and past customers
5 should have contributed to their recovery. Furthermore, today's customers should not bear
6 full financial responsibility for the Company's past managerial decisions that resulted in
7 backlogged maintenance and poor reliability performance. To reduce intergenerational
8 inequity among customers, and to equitably assign shared responsibility for the rate
9 impacts of surge spending, witness Jester proposes that surge costs be held as regulatory
10 assets for potential securitization.

11 Additionally, I present evidence showing that residential customers pay for reliability
12 improvements far out of proportion to the benefits they realize. Thus, I recommend that the
13 Commission require the Company to analyze reliability benefits and propose changes as
14 part of its next rate filing that more closely align distribution allocations with principles of
15 cost causation.

16 **Q. Please summarize the Company's electric distribution reliability investment**
17 **programs.**

18 A. The Company's electric distribution strategy and investments program comprises multiple
19 distinct distribution focus areas, including Low Voltage Distribution (LVD) and Metro
20 systems, High Voltage Distribution (HVD) system, Grid Automation, Streetlighting,
21 Forestry Line Clearing, and Service Restoration.

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1 **Q. Please summarize the Company's line clearing program proposed in this case.**

2 A. The Company's line clearing program is divided into two parts: HVD and LVD line
3 clearing. The HVD program manages the vegetation along the Company's high voltage
4 systems and currently operates on a four-year clearing cycle.⁴⁰ The LVD program manages
5 vegetation along the low voltage systems and has been working towards a seven-year
6 effective clearing cycle, which it has yet to attain.⁴¹

7 The Company proposes maintaining its current four-year HVD clearing cycle while
8 ramping up to a five-year clearing cycle for its LVD systems. It targets the end of the 2030-
9 2031 test period to achieve the shortened LVD clearing cycle.⁴²

10 **Q. Does the Company anticipate the line clearing program will improve its reliability**
11 **metrics?**

12 A. Yes, it does. Figures 9 and 10 on page 30 of witness Stewart's testimony project that the
13 line clearing program will lead to a 27% reduction in SAIFI including major event days
14 (MEDs) and a 29% reduction in SAIDI including MEDs in 2030 compared to 2025
15 values.⁴³

⁴⁰ Direct Testimony of Sara E. Stewart, p. 12. 4:6.

⁴¹ *Id.* at 12, 13:14.

⁴² *Id.* at 15, 18:23 to 16, 1:3.

⁴³ *Id.* at 30.

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1 **Q. Is the Company’s line clearing program as proposed in this case a surge?**

2 A. Yes, it is. As mentioned, the Company proposes ramping up its LVD line clearing work to
3 achieve a five-year cycle. This clearing cycle target is consistent with the recommendations
4 put forth in the Liberty Audit.⁴⁴

5 The Liberty Audit’s recommendation is to achieve a four- or five-year line clearing cycle
6 for LVD circuits by year-end 2028, which the Company asserts is not operationally
7 feasible.⁴⁵ Instead, the Company aims to reach this cycle by the end of the 2030-2031 test
8 period. To reach this target cycle, the Company must devote significantly more spending
9 towards the line clearing program compared to both historical spending levels and what
10 will be required to maintain its five-year cycle once it is realized.⁴⁶

11 **Q. Do you support the Company’s proposed surge spending on LVD line clearing?**

12 A. I support the Company’s operational plan and spending level, which I consider to be
13 consistent with recommendations of the Liberty Audit. I also agree that line clearing surge
14 costs should be held as regulatory assets, but I do not agree with the Company’s calculation
15 of the surge amount.

16 **Q. How does the Company calculate the value of its forestry surge spending?**

17 A. Witness Stewart establishes the Company’s forestry “baseline” spending for the test year
18 by taking the current projection for the annual expense to maintain the five-year cycle after
19 it is achieved in the 2030-2031 test period, adjusted (or deflated) to the projected test period

⁴⁴ *Id.* at 18, 10:16 to 19, 1:5.

⁴⁵ *Id.* at 19, 10:12.

⁴⁶ *Id.* at 36, Figure 13.

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dollars.⁴⁷ In other words, witness Stewart estimates today's baseline by working backwards in time from a hypothetical future steady-state (i.e., post-surge) costs. Based on the amount by which proposed forestry spending exceeds this backcasted baseline, the Company is requesting to create a regulatory asset related to the program for \$22.24 million.⁴⁸

The Company's methodology to calculate the baseline is speculative and novel. It uses a projection of expenses several years into the future to backcast the baseline costs of work to be performed in the test year. In any other expense category, the Company would adjust historical costs forward to estimate future costs. Line clearing should be treated no differently.

Q. Please explain how you propose to calculate the value of the Company's forestry surge spending.

A. Put simply, I compare PAI-adjusted historical spending to proposed spending; the difference is the surge.

The Company proposes spending \$186,684,000 on forestry in the test year. (Table 4) Adjusting its historical test year spending for PAI yields a baseline figure of \$113,977,000. Any proposed amount in excess of that figure represents increased activity over adjusted baseline, or surge. That amount is \$72,707,000, which is the figure witness Jester proposes for regulatory asset treatment and potential securitization.

⁴⁷ *Id.* at 35, 12:14.

⁴⁸ *Id.* at 48, Figure 23.

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1 **Q. Is the Company planning any additional surge work on its distribution system to**
2 **improve reliability?**

3 A. Yes, it is. The Company proposed to invest significant capital to replace poles in its LVD
4 system. It plans on replacing 3,076 poles at a cost of \$29,711,000 in the bridge period and
5 12,500 poles at a cost of \$127,500,000 in the projected test year.⁴⁹ This is a notable increase
6 compared to the Company's U-21585 proposal of replacing 1,666 poles in that case's
7 bridge period and 149 poles in its test period.⁵⁰ The Liberty Audit confirmed a significant
8 backlog in pole replacement and recommended catch-up investments.

9 **Q. Do you support the Company's LVD pole replacement plans?**

10 A. I support the surge in pole replacements but have the same concerns about equitable
11 recovery of its costs as I have with forestry surge costs. Again, it is not equitable to charge
12 today's customers for costs that yesterday's customers should have contributed to. Nor is
13 it equitable to require customers to pay normal recovery of costs that have escalated
14 because of the Company's decision to underinvest in past maintenance. Thus, I estimate
15 the amount of the surge, and witness Jester proposes that amount should be treated as a
16 regulatory asset for potential securitization.

17 **Q. What cost do you calculate for the pole replacement surge?**

18 A. Once again, I start with historical annualized costs and apply the PAI factor to arrive at a
19 test-year baseline. Any proposed amount in excess of that baseline is surge spending.

⁴⁹ Direct Testimony of Jennifer M. Partlan, p. 69, Figure 35.

⁵⁰ Case No. U-21585, Direct Testimony of Donald A. Lynd, 4 Tr 579, Figure 39.

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For pole replacement, the Company estimates it will spend \$29.71 million in the 16-month bridge period, which annualizes to \$22.28 million. I adjust that figure for PAI and round upward to arrive at the test-period baseline spending of \$25 million. The Company proposes to spend \$127.5 million in the test year, therefore the surge amount is \$102.5 million. Witness Jester proposes this amount be treated as a regulatory asset for potential securitization and the baseline amount of \$25 million should be added to rate base.

Table 5: CUB Proposed PAI adjustments to LVD pole replacement ⁵¹

Historical					Total costs and adjustments						
					Bridge period projections and adjustments		Test-year projections and adjustments				
							CUB projected bridge-year target = (h) + (i) + (j) + (l) + (m) + (n); 16 months ended 4/30/2026	Company proposal = (f); 16 Months Ended 4/30/2026	CUB projected test-year target = (p) + (k) + (o); 12 months ended 4/30/2027	Company proposal = (g) 12 Months Ended 4/30/2027	Test-year disallowance based on PAI = (w) - (x); 12 months ended 4/30/2027
Description	Source	12 Months Ended 12/31/2024	16 Months Ending 4/30/2026	12 Months Ending 4/30/2027							
Pole replacements PAI baseline estimate	Direct testimony of Jennifer M. Partlan, p. 69, Fig. 35	N/A	29,711	127,500		29,711		22,638	127,500		102,500
								Rounded to 25,000			(127,500 - 25,000)

Q. Do you have concerns with how the Company allocates its reliability spending amongst customer classes?

A. Yes, I do. Reliability improvements are allocated using the same factors as other distribution system expenditures but may not have the same cost causation.

The Company uses the cost-of-service study (COSS) to allocate distribution expenditures and investments. The Roadmap incorporates a mix of operational costs (line clearing) and capital investments (line clearing and LVD and HVD investments). I summarize the

⁵¹ Exhibit CUB-26, Proposed LVD Pole Replacement Surge.

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account numbers and allocation factors used for each combination of HVD/LVD and capital/O&M costs in Table 6.

Table 6 - Distribution Allocation Factors

	Expenditure Type	Account Number	Allocation Factor(s)
HVD	Capital	364/365	122/123/124/125/230
	O&M	593	121/122
LVD	Capital	364/365	230/231/235
	O&M	593	307

Table 7 shows the allocations across each customer class for the allocation factors listed in Table 6.

Table 7 - Customer Class Allocations

Allocation Factor	Residential	Commercial Secondary	Lighting & Unmetered	Primary	Rate GSG
122	50.5074	23.5252	0.3727	24.9190	0.6757
123	0.0000	0.0000	0.0000	95.2174	4.7826
124	0.0000	0.0000	0.0000	95.3595	4.6405
125	50.7580	23.6420	0.3745	24.8494	0.3760
230	54.1983	25.2444	0.3999	20.0795	0.0779
231	67.8814	31.6177	0.5009	0.0000	0.0000
235	67.8814	31.6177	0.5009	0.0000	0.0000
307	66.5223	25.4012	0.3887	7.5950	0.0927

Allocation factors 123 and 124 are applicable only for HVD capital investments. However, HVD investments could also be assigned to allocation factors 122, 125, or 230, depending on the voltage of the line. This means that the residential rate class is allocated at least 50%, and up to 67% of all non-HVD capital investments and operational expenditures, as well as a portion of HVD capital investments.

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Q. Are the Company's allocators for distribution investments and expenditures equitably distributed amongst customer classes?

A. No, the benefits are very unequally distributed across rate classes. To the extent some distribution system investments are made to address (i.e., are caused by) reliability concerns, the allocators being used appear to be inequitable.

The Company appropriately recognizes that there is a monetizable benefit in avoided outage costs due to increased reliability. ~~Specifically, the Company asserts that its SAIDI, the same model~~ Further, the Reliability Roadmap model that the Company utilizes to determine the \$6.1 billion, separates the benefits into three classes: residential, small commercial and industrial (C&I), and medium/large C&I.

I include these benefits broken down by class, as well as the proportion of reliability benefits received compared to the total \$6.1 billion in reliability benefits, in Table 8.

Table 8 - Distribution of Monetized Reliability Benefits⁵²

Class	Economic Benefit (\$000s)	Percentage of Total Benefit
Residential	92,592	1.9%
Small C&I	4,408,851	90.4%
Medium/Large C&I	375,583	7.7%
Total	6,107,573	100%

Table 8 demonstrates that the Company's own modeling shows that the residential customer class will receive only a very small fraction of the economic reliability benefits from these investments and expenditures. The current allocation methodology allocates up to two-thirds to the residential rate class.

⁵² Exhibit CUB-27, SAIDI Benefits Modified U21870-AG-CE-0424_Kelly_ATT_1.

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1 **Q. Why do non-residential customers receive the vast majority of economic benefits from**
2 **improved reliability despite being a minority of the Company's customers?**

3 A. While it is true that non-residential customers are a small percentage (about 12%) of the
4 Company's 1.9 million customers,⁵³ the economic impact of an outage is substantially
5 larger for a non-residential customer than it is for a residential customer. C&I customers
6 simply have costs on a larger scale than an individual household's budget. When a non-
7 residential customer loses power, they are either partially or fully restricted in their ability
8 to conduct business. Examples of such impacts could include additional labor needed to
9 make up production losses, additional materials to restart a production process, the need to
10 operate backup power generators and lost sales at commercial locations. This results in a
11 combination of lost revenue and increased costs, impacting their financial performance.

12 A residential customer's cost of interrupted power is smaller than a non-residential
13 customer's. Still, lost power creates real and tangible costs for the residential class, such as
14 needing to replace spoiled food, relocating to a location with power, or lost income due to
15 the inability to work. When monetized, however, these impacts are simply less than those
16 experienced by C&I customers.

17 The Company's modeling reflects this difference by putting the average cost of interruption
18 (COI) at \$0.04 per minute with a standard deviation of \$0.05 per minute for residential
19 customers in 2025.⁵⁴ For Small C&I customers, the average COI is \$14.79 per minute with

⁵³ A-16 (EAD-1), Sch F-1 and WP-EAD-1-48, Input2 sheet, Cell G183.

⁵⁴ Exhibit CUB-27, SAIDI Benefits Modified U21870-AG-CE-0424_Kelly_ATT_1.

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1 a standard deviation of \$9.81 per minute. For Medium/Large C&I customers, the COI is
2 \$235.10 per minute, and the standard deviation is \$127.67 per minute.

3 **Q. Under the current allocation methodology, will residential customers pay more than**
4 **the reliability benefits they receive from these investments?**

5 A. Yes, residential customers will pay substantially more than the benefits they receive. As
6 demonstrated in Table 8, residential customers will only derive approximately 1.9% of the
7 economic benefits from increased reliability due to these investments and expenditures.
8 With the current allocation methodology, they are being asked to cover the vast majority
9 of the costs of this work.

10 For the sake of simplicity, let us focus on just the LVD line clearing program. Between
11 2025 and 2030, the Company is anticipating \$1,161,440,000 in operational expenditures to
12 clear its LVD system.⁵⁵ Since these are O&M expenses, they are assigned to allocation
13 factor 307, which puts 66.5223% of the spending towards the residential class. This means
14 that residential customers will pay around \$772,617,000 over that period. However, this
15 class will only receive approximately \$115,900,000 in benefits for the entirety of the
16 Roadmap (which is inclusive of line clearing).⁵⁶ Without taking into consideration the
17 money allocated to them for the rest of the capital investments in the Roadmap, the
18 residential class will unjustly be paying several hundred millions of dollars more than the
19 benefits they will realize.

⁵⁵ Exhibit CUB-28, 2025-2030 Line Clearing O&M.

⁵⁶ 1.9% x \$6.1 million in projected economic benefits.

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1 **Q. Please summarize your recommendations on reliability improvement investments**
2 **and expenditures allocation.**

3 A. First, I recommend that the Commission reject the Company's proposed surge amount of
4 \$22.24 million associated with its Forestry O&M costs. Instead, I recommend the
5 Commission adopt the surge amount of \$72.71 million, calculated as the excess of
6 projected test-year costs over the historical plus PAI. Witness Jester recommends
7 securitizing these costs.

8 Second, I propose that the Commission allow \$25 million associated with the LVD Lines
9 pole replacement program to be included in the rate base and treat the remaining ~~\$127.5~~
10 \$102.5 million as a surge. Witness Jester recommends treating these surge costs as a
11 regulatory asset, potentially eligible for securitization.

12 Third, I recommend the Commission require the Company to conduct an analysis of its
13 allocation methodology for distribution costs, particularly to the extent that distribution
14 investments are justified on the basis of reliability and propose revisions as part of its next
15 rate case. The work that the Company is doing to improve reliability is needed, but under
16 the current allocation methodology, there is a severe misalignment between the costs and
17 benefits to each customer class.

18 **VI. UNDERGROUNDING**

19 **Q. Which Company witness's testimony do you address in this part of your testimony?**

20 A. I am addressing the testimony of Company witness Kelly.

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1 **Q. Please summarize the history of the Company’s undergrounding strategy.**

2 A. In Case No. U-21389, the Company proposed an undergrounding pilot to explore how
3 undergrounding can help improve reliability for customers, comparing the benefits and
4 costs of this work. The Commission approved the proposal, resulting in approximately 10
5 miles of undergrounding that the Company executed in 2024 and early 2025. In the
6 subsequent rate case (Case No. U-21585), the Company proposed expanding the pilot with
7 an additional 25 miles of undergrounding. The Commission did not approve the expansion
8 because the results from the initial pilot were not yet available.

9 **Q. Please summarize the Company’s undergrounding proposal in this case.**

10 A. The Company proposes undergrounding 50 miles in the test year.⁵⁷ The Company projects
11 a per-mile cost of \$400,000 for the projects it has identified, a lower unit cost than what
12 was achieved in its pilot.⁵⁸ It believes that cost savings will occur due to better
13 identification of economically competitive projects and being able to perform the work at
14 scale. The Company also intends to scale the program to underground 400 miles per year
15 by 2028.⁵⁹ Exhibit A-167 (JMP-21) page 21 outlines the 28 undergrounding projects the
16 Company includes in the instant case.

17 **Q. Does witness Kelly’s testimony justify the scope of the Company’s proposed**
18 **undergrounding?**

19 A. No, it does not. Witness Kelly does not assess the costs and benefits of individual
20 undergrounding projects he proposes. When this analysis is conducted, I find that half of

⁵⁷ Witness Kelly testimony, p. 67, line 2.

⁵⁸ Witness Kelly testimony, p. 64, lines 21 through 22.

⁵⁹ Witness Kelly testimony, p. 67, lines 8 through 9.

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1 the projected benefits of this program would be realized from a small minority of the 50
2 miles proposed. Given how expensive undergrounding is, the Company should focus its
3 learning and cost-curve efforts on the few projects that have encouraging cost-benefits
4 prospects.

5 **Q. Please explain how you determined which undergrounding projects will be the most**
6 **cost-effective.**

7 A. On page 21 of Company Exhibit A-167 (JMP-2), the Company outlines the benefits that
8 each undergrounding project is expected to yield. The benefits are customer outage minutes
9 avoided and range from about 22,000 minutes to 436,500 minutes per year depending on
10 the project. The Company also provides yearly estimates of the average cost of interruption
11 to its customers for 2025 through 2032. For the residential class, this shakes out to be about
12 \$0.04 per minute in 2025 growing to \$0.05 per minute in 2032.⁶⁰ Applying the Company's
13 discount rate of 1.5%,⁶¹ I can then calculate the net present value (NPV) of avoided outages
14 for each project through 2032.

15 **Q. What is the value of avoided outages for the proposed undergrounding projects**
16 **through 2032?**

17 A. For the entire proposed program, the eight-year present value of avoided outages for
18 residential customers is \$689,700.⁶² However, these benefits are very unevenly distributed

⁶⁰ Exhibit CUB-27, SAIDI Benefits Modified U21870-AG-CE-0424_Kelly_ATT_1.

⁶¹ Company Response to U21870-AG-CE-0430, Attachment U21870-AG-CE-0430_Kelly_ATT_1, Model worksheet, cell E9.

⁶² Exhibit CUB-29, Present Value of Each Undergrounding Project.

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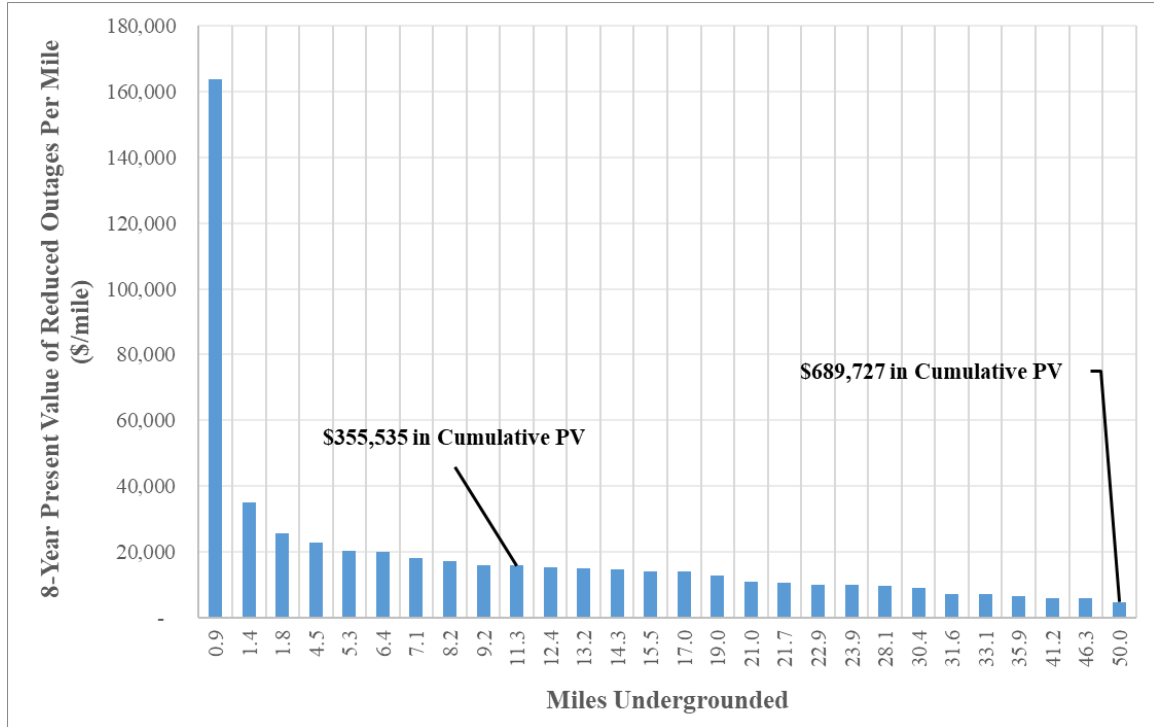
1 among the proposed projects. Half of the residential customer benefits are realized from
2 only 11.3 of the 50 miles of undergrounding proposed.

3 **Q. Please explain how you determined this scope.**

4 A. To determine the scope of 11.3 miles, I divided the aforementioned eight-year present value
5 of avoided customer outages by the number of miles being converted for each project. I
6 then sorted the present value per mile and calculated a running total (or, cumulative benefit)
7 to determine at what point approximately half of the program's benefits are realized. Figure
8 4 displays the results of this process.

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Figure 3 - Economic Benefits of Proposed Undergrounding⁶³



As ~~Figure 4~~ **Figure 3** shows, the benefits per mile exhibit diminishing returns. The cumulative present value for the entirety of the program is \$689,727. Over half of this value – \$355,535 – is met by undergrounding only 11.3 miles worth of projects and additional benefit gains continue to diminish thereafter. Whereas the proposed program would underground 50 miles of cable at a cost of \$20 million, the reduced scope I recommend would create fully half of the projected customer benefits for only about 13% of the projected cost.

I show which of the projects constitute the ~~6.4~~ **11.3** miles in Table 9.

⁶³ Exhibit CUB-30, Sorted Benefits.

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1 Table 9 - MNSC Proposed Undergrounding Projects

Line Number ⁶⁴	Project Description	Miles
8	LAKE LEANN/LAKE LEANN/282	1.0
10	PECK ROAD/M-91/473	2.1
11	PENINSULA/MAPLETON/124	1.1
12	SPRUCE ROAD/EAST BAY/693	0.5
13	SPRUCE ROAD/EAST BAY/868	0.7
16	BLACKMAN/SANDSTONE/404	2.7
17	KOLASSA/MATTESON/187	0.8
18	TRUFANT/GOWEN/847	1.1
22	WHITTEMORE/SAND LAKE/28	0.9
28	BROOKLYN/BROOKLYN/811	0.4

2 **Q. Please summarize your recommendations for the undergrounding program.**

3 A. I recommend the Commission greatly reduce the scope of the Company's undergrounding
4 program. Undergrounding is very expensive and the cost-benefit of individual projects
5 varies enormously, making it important to evaluate each project individually rather than at
6 an aggregated program level The Commission should reduce the scope of the program to
7 just the high-impact projects (shown in Table 9) so that revenue requirement impacts are
8 limited during this exploration period. This would result in a disallowance of \$15,480,000
9 in the test period.⁶⁵

⁶⁴ Company Exhibit A-167 (JMP-2), p. 21

⁶⁵ (50 miles – ~~6.4~~ 11.3 miles) * \$400,000
per mile

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VII. SERVICE RESTORATION FUNDING MECHANISMS

Q. Which Company witness' testimony do you address in this part of your testimony?

A. I am addressing the testimony of Company witness Snider.

Q. Please summarize the Company's proposed mechanisms related to the Service Restoration O&M spending.

A. Company witness Snider has put forth two proposals for new accounting mechanisms related to the Service Restoration O&M spend:

1. **Service Restoration Resiliency Fund (SRRF):** The Company proposes establishing a regulatory liability to capture any underspent service restoration O&M dollars from prior years. These surplus funds would be earmarked for future service restoration O&M needs and would be utilized as a first source when actual spends exceed authorized amounts. In effect, the SRRF serves as a buffer that shields the Company during the years when restoration costs surpass the amounts embedded in authorized rates. The SRRF would be capped at \$30.7 million, with any balance above the cap refunded to customers through a bill credit.⁶⁶

2. **Extraordinary Storm Accounting (ESA):** The Company also proposes a deferred accounting mechanism that would allow for deferred recovery of restoration costs associated with certain 'extraordinary storms,' subject to reasonableness and prudence review, when the total service restoration costs exceed the authorized base amounts. The Company defines "extraordinary storms" as storms that cause at least 300,000 customer outages over a seven-day period or that trigger a State of Emergency

⁶⁶ Direct Testimony of Andrew R. Snider, p. 23, 18:24.

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1 declaration from the Governor's office. Excess costs related to events unrelated to these
2 'extraordinary storms' would not be eligible for recovery under ESA.

3 **Q. Has the Commission addressed similar proposals previously?**

4 A. Yes, the Commission has addressed and rejected similar proposals on multiple occasions.
5 Most recently, in the Company's last electric rate case, U-21585, the Commission rejected
6 the Company's Service Restoration Cost Sharing Mechanism (SRCSM), that would have
7 allowed the Company to recover 50% of the excess service restoration costs above the
8 authorized base amounts.⁶⁷ In instances where the Company underspent on service
9 restoration, the ratepayers would have received 50% of the difference as a refund.

10 The Commission rejected this proposal, finding that it did not provide sufficient benefit for
11 ratepayers to outweigh the additional risk it would place on them.⁶⁸ The ALJ noted that,
12 "the evidence presented shows that customers are unlikely to realize a refund given that
13 storm restoration expense has been more than predicted for many years, with no prospect
14 for a different outcome during the test year." The Commission agreed with the ALJ's
15 assessment and added that, "While severe storms are unpredictable, the company has more
16 control over the costs associated with restoration than customers do and therefore should
17 bear more of the risk."⁶⁹

18 In addition to U-21585, the Company has proposed similar cost-sharing or reserve
19 mechanisms in several prior proceedings. Taken together, the Commission has rejected at
20 least five such proposals over the past decade, consistently finding that they provide

⁶⁷ Case No. U-21585, PFD, p. 422.

⁶⁸ Case No. U-21585, Order, March 21, 2025, p.313.

⁶⁹ *Id.* at 314.

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asymmetric benefits to the Company, shift the risks associated with restoration cost volatility to ratepayers, and reduce the Company's accountability for cost control.⁷⁰

Q. How are the Company's proposals in this case different from the SRCSM and its historical versions?

A. They are not significantly different. While the Company has repackaged its approach in this case by presenting two distinct mechanisms, their underlying objectives and design repeat those of SRCSM. They continue to skew the risks associated with volatile service restoration costs away from the Company towards the ratepayers and reduce Company incentives to implement cost efficiency in its service restoration.

- SRRF, like SRCSM would have done, creates a mechanism for the Company to retain ratepayer-paid dollars in years when the Company underspends on service restoration. While under SRCSM, 50% of the underspend would have been refunded to ratepayers, SRRF weakens that threshold even further. Under SRRF, 100% of the underspent funds would be earmarked for future service restoration, effectively reducing the Company's risk in the future, with no upside to the ratepayers, until the fund reaches its cap of \$30.7 million, when refunds would be issued. While the Company claims that the likelihood of underspending should increase in the future, it provides no evidence to support it. On the contrary, witness Snider acknowledges that extreme weather conditions will become more frequent in the coming years⁷¹ and "are the main cause of increased service restoration spending and pose the largest risk to sustainable service restoration operations,"⁷² thus

⁷⁰ Case No. U-21585, PFD, p. 425.

⁷¹ Snider Direct, p. 8, 14:16.

⁷² *Id.* at 28, 18:19.

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1 leading to the Company's proposal for ESA. The fact that the Company is simultaneously
2 seeking ESA underscores that the real risk is overspending, not underspending – making it
3 very unlikely that the ratepayers will see any benefits from the underspend years. SRRF
4 creates asymmetric benefits for the Company and its shareholders at the expense of its
5 ratepayers.

- 6 • ESA, like SRCSM, uses a deferred accounting mechanism to recover excess restoration
7 costs. The primary difference is that ESA is applicable only for costs related to
8 'extraordinary storms,' and their recovery will require the Company to demonstrate their
9 prudence and reasonableness. While the additional prudence review is an improvement,
10 the mechanism remains problematic. Again, the high expected frequency and costs
11 associated with extraordinary storms mean that it is very likely that ESA will be triggered
12 often. Allowing deferred recovery for such events reduces the risk for the Company and its
13 shareholders while increasing the ratepayers' exposure to restoration costs associated with
14 large, extreme weather-related events.

15 In essence, both SRRF and ESA embody the same fundamental imbalance as the
16 Company's previous proposals and shift cost volatility and risk from the Company and its
17 shareholders to its ratepayers.

18 **Q. Does the Company's restoration performance in recent years justify the proposed**
19 **mechanisms?**

20 A. No, the Company's performance does not justify these cost recovery mechanisms. As
21 discussed previously, the Company's overall reliability performance has been among the
22 worst in the nation. And while the Company details supposed improvements in its
23 restoration performance, SAIDI All Weather shows no signs of sustained and meaningful

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improvement.⁷³ In the context of this poor reliability performance, Consumers Energy's continued proposals for cost recovery mechanisms that increase risks for ratepayers are unreasonable. Nothing indicates that these mechanisms will improve the Company's efficiency in service restoration operations and overall cost control. Furthermore, they make today's ratepayers financially responsible for storm damage substantially attributable to the Company's past distribution system maintenance practices.

Q. Do you have other concerns pertaining to these mechanisms? If so, please elaborate.

A. Yes. I am particularly concerned about the lack of any prudence or oversight standards associated with the proposed SRRF. It allows the Company to retain and later draw upon surplus ratepayer-funded dollars without any such review at the time of use. Once funds are deposited into SRRF, the Company may use them to cover future service restoration costs without demonstrating whether those costs were efficient, necessary, or reasonably incurred.

Company witness Snider states that SRRF is preferable to the current practice, where the Company simply reallocates any underspent restoration dollars to other O&M categories. I disagree. While not ideal, current practice encourages internal budgetary discipline and incentivizes the Company to reduce its service restoration costs, whereas SRRF simply would not.

⁷³ <https://cubofmichigan.org/reports/utility-performance-report-2025-edition/>, Energy Costs tab, SAIDI with MEDS data (last accessed September 18, 2025); MPSC Distribution System Reliability Metrics, SAIDI All Weather Michigan Utilities and IEEE Quartile Benchmarks, <https://www.michigan.gov/mpsc/consumer/electricity/distribution-system-reliability-metrics>, Accessed 9/29/2025 .

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1 **Q. What is your recommendation?**

2 A. I recommend the Commission reject the Company's proposed Service Restoration
3 Resiliency Fund (SRRF) and Extraordinary Storm Accounting (ESA) mechanisms. There
4 is very little that is new here compared to past proposals the Commission has repeatedly
5 rejected. Both mechanisms provide the Company with an opportunity to recover costs from
6 customers in years when they overspend on service restoration; however, they don't
7 provide the ratepayers with the same relief when the Company underspends.

8 Until the Company demonstrates sustained efficiency gains that offset the growing
9 pressures from extreme weather, it is far more reasonable to expect the likelihood of
10 underspending in future years to be low, meaning that the Company and its shareholders
11 stand to benefit more from such mechanisms than the ratepayers.

12 Furthermore, these proposals make today's ratepayers financially responsible for storm
13 restoration costs that are, in large part, the result of the Company's past underspending in
14 distribution system maintenance and resilience. Rather than ensuring accountability, these
15 asymmetric mechanisms transfer the risks associated with the volatility of restoration costs
16 from the Company and its shareholders to its ratepayers, who have little control over the
17 Company's restoration efforts. I therefore propose that the Commission reject both these
18 proposals.

19 **VIII. RECOMMENDATIONS**

20 **Q. Please summarize your conclusions and recommendations to the Commission.**

21 A. I recommend that the Commission:

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- 1 1. Completely disallow ~~\$59.9~~^{\$59.5} million of O&M costs beyond the 2024 historical
2 actuals plus PAI baseline.
- 3 2. Allow recovery of an additional \$72.7 million of forestry surge costs related
4 to its LVD and HVD Line Clearing programs; witness Jester recommends
5 securitizing these costs.
- 6 3. Allow recovery of \$127.5 million of capital expenditures related to the LVD
7 Lines Reliability-pole replacement program; \$25 million of this amount
8 should be added to rate base and witness Jester recommends treating the
9 remaining \$102.5 million as a regulatory asset potentially eligible for
10 securitization.
- 11 4. Direct the Company, in its next rate case, to present its O&M costs and capital
12 expenditure projections against historical actuals plus PAI benchmark and
13 require it to justify any spending above this benchmark as driven by sales,
14 statutory, or performance requirements, with evidence that such expenditures
15 will produce measurable improvements in service.
- 16 5. Require the Company, in its next rate case, to present an analysis of its current
17 allocation methodology for distribution costs, particularly those justified on
18 the basis of reliability improvements and propose alternative mechanisms for
19 allocation of reliability costs that are more closely aligned with principles of
20 cost causation.
- 21 6. Reduce the scope of the Overhead-to-Underground conversion program to ~~six~~
22 ten projects proposed in Table 9.

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1 7. Disallow \$15.4 million in capital expenditures corresponding to the reduced
2 Overhead-to-Underground conversion.

3 8. Reject the Company's proposed Service Restoration Resiliency Fund (SRRF)
4 and Extraordinary Storm Accounting (ESA) mechanisms.

5 My silence regarding any position taken by the Company in its application or direct
6 testimony in this proceeding does not indicate my endorsement of that position.

7 **Q. Does that complete your testimony?**

8 **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 generation
and distribution of electricity and for other
relief.

Case No. U-21870

PROOF OF SERVICE

On the date below, an electronic copy of **Revised Direct Testimony of Richard J. Bunch on behalf of Citizens Utility Board of Michigan** was served on the following:

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[signature page below]

The statements above are true to the best of my knowledge, information and belief.

Troposphere Legal, PLC
Counsel for CUB

Date: October 9, 2025

By: _____
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1 MR. BZDOK: Thank you, Your Honor. That
2 concludes the witnesses. I now have nine hearing
3 exhibits, discovery response, and related exhibits, which
4 were uploaded and circulated by email to the parties in
5 connection with waivers of cross, admission of exhibits in
6 lieu of cross-exam.

7 (Simultaneously speaking)

8 MR. BZDOK: All right. Thank you. So, I would
9 move at this time, to admit into evidence Exhibit MEC-42,
10 which is Discovery Response, MNSC CE 865. MEC-43, which
11 is Discovery Response MNSC CE 866. MEC-44, which is
12 Discovery Response MNSC CE 867, and its attachment. MEC-
13 45, which is Discovery Response MNSC CE 868. MEC-46,
14 which is Discovery Response MNSC CE 801. MNS -- sorry.
15 MEC-47, which is Discovery Response MNSC CE 802. MEC-48,
16 which is Discovery Response MNSC SLT 1, 2, and 3. MEC-49,
17 which is the full set of the MPSC Staff's answer to MNSC
18 Discovery Response Questions 1 and 2 from the first
19 Discovery Requests to Staff. And finally, MEC-50, which
20 is attachment 133 to the Consumers Energy Part 3 filing
21 more requirements for this case.

22 JUDGE THOITS: Are there any objections to the
23 admissions of these exhibits?

24 Hearing none. Exhibits MEC-42 through MEC-50
25 are admitted.

1 MR. BZDOK: Thank you, Your Honor. That
2 concludes the items I wish to bind and admit today on
3 behalf of MNSC.

4 JUDGE THOITS: Thank you. Is Mich -- excuse me,
5 Energy Michigan available and ready to bind in?

6 MR. OOMS: Yes, Your Honor.

7 JUDGE THOITS: All right. Please proceed.

8 MR. OOMS: Thank you, Your Honor. At this time
9 and in accordance with the stipulations of the parties,
10 Energy Michigan moves to admit to bind in the direct and
11 rebuttal testimony of Mr. Alexander J. Zakem, and to admit
12 the exhibits that he sponsored along with his testimony.
13 His direct testimony consists of a cover page and 35 pages
14 of questions and answers. His rebuttal testimony consists
15 of a cover page and four pages of questions and answers,
16 and the exhibits EM-1, EM-2, EM-3, EM-4, and EM-5.

17 JUDGE THOITS: Are there any objections to the
18 admission of this testimony or these exhibits?

19 Hearing none on the direct and rebuttal
20 testimony of Alexander Zakem is bound into the record, and
21 Exhibits EM-1 through EM-5 are admitted.

22

23

24

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 generation and distribution of)
electricity and for other relief.)
_____)

Case No. U-21870

DIRECT TESTIMONY
OF
ALEXANDER J. ZAKEM
ON BEHALF OF
ENERGY MICHIGAN

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

2 A. My name is Alexander J. Zakem, and my business address is 46180 Concord, Plymouth,
3 Michigan 48170.

4
5 **Q. On whose behalf are you testifying in this proceeding?**

6 A. I am testifying on behalf of Energy Michigan.
7

8 **Q. Please state your professional experience.**

9 A. Since January of 2004, I have been an independent consultant providing services to various
10 clients, including Energy Michigan and its members.

11
12 From March 2002 to December 2003, I was Vice President of Operations for Quest Energy,
13 an alternative energy supplier in Michigan. My responsibilities included the overall
14 direction and management of Quest's power supply to its retail customers. This included
15 power supply planning, development of customized products, negotiation with suppliers,
16 planning and acquiring transmission rights, and scheduling and delivery of power. It also
17 included managing risk with respect to market price movements and variation of customer
18 loads.

19
20 Prior to joining Quest, I was employed by Detroit Edison from 1977 to 2001, where from
21 1998 to 2001 I was the Director of Power Sourcing and Reliability, responsible for
22 purchases and sales of power for mid-term and long-term periods, planning for generation

1 capacity and purchase power needs, strategy for and acquisition of transmission rights, and
2 related support for regulatory proceedings.

3
4 Additional experience, qualifications, and publications are provided in Exhibit EM-1 (AJZ-
5 1).

6
7 **Q. Have you testified as an expert witness in prior proceedings?**

8 A. Yes. I have testified as an expert witness in many proceedings before the Michigan Public
9 Service Commission ("Commission") on topics such as standby rates, retail rates and
10 regulations, recovery and allocation of costs and revenues, and the effects of rate
11 restructuring. I have also testified before the Federal Energy Regulatory Commission
12 ("FERC"). Case citations are provided in Exhibit EM-1 (AJZ-1). In addition, I have
13 participated in various Commission-sponsored workshops and stakeholder working
14 groups.

15
16 **Q. Are you sponsoring any exhibits?**

17 A. Yes. I am sponsoring the following exhibits:

- 18 • Exhibit EM-1 (AJZ-1): Qualifications
- 19 • Exhibit EM-2 (AJZ-2): Example Calculation of SRM Charge --
20 Projected vs. Actual
- 21 • Exhibit EM-3 (AJZ-3): History of SRM Charge True-Ups
- 22 • Exhibit EM-4 (AJZ-4): Recommended Changes to SRM Charge Calculation

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

2 A. On behalf of Energy Michigan, I am addressing Consumers Energy's proposed State
3 Reliability Mechanism ("SRM") Capacity Charge ("SRM Charge") regarding the method
4 and results of the "true-up" that is included in setting the SRM Charge.

5

6 **Q. Would you summarize your conclusions and your recommendations to the**
7 **Commission?**

8 A. In the calculation of the SRM Charge in this proceeding, Consumers Energy has included
9 a negative \$461,000 (000) adjustment to the calculation of the SRM Charge as a formulaic
10 "true-up" between (a) the value of energy market sales net of fuel projected in the
11 determination of the SRM Charge two cases prior in Case No. U-22389 and (b) the value
12 of actual energy market sales net of fuel that should be used. A true-up between projected
13 and actual is authorized by the SRM statute, MCL 460.6w.

14

15 The \$461 million true-up represents a forecast error in the projection of energy market sales
16 net of projected fuel. Since the projection of energy market sales net of projected fuel is
17 included in the SRM Charge set in one case and -- under the present process -- is reversed
18 the next time the SRM Charge is set in another case, with actual values substituted, thus
19 also affecting the SRM Charge set in the latter case, both the utility and the customer who
20 pays the SRM Charge are affected by the true-up. Further, because the true-up amount in
21 the SRM Charge affects the capacity and non-capacity prices in rates of utility customers
22 who do not pay the SRM Charge, all customers who pay power supply prices are affected
23 by the method and quantification of the true-up process. This price instability will be

1 explained more in the "Recommendations" section of this testimony. Therefore, it is
2 important to both the utility and the customer paying the SRM Charge that the true-up be
3 correct such that neither the utility nor the customer is advantaged or disadvantaged over
4 multiple determinations of the SRM Charge, regardless of when a customer pays an SRM
5 Charge.

6
7 This testimony and exhibits will show that:

- 8 • **Implementation Errors:** The present true-up method ends up with the wrong
9 total amount of the SRM Charge being paid by the customer and collected by the
10 utility in each and every situation that it is applied.
11
- 12 • **Cost of Service:** The present true-up method is inconsistent with cost-of-service
13 principles and the cost-of-service statute MCL 460.11(1).
14
- 15 • **Workable True-Up:** There is a simple and precise way to implement an equitable
16 and accurate true-up for the SRM Charge, which I am recommending, such that
17 neither the customer nor the utility is advantaged or disadvantaged. This
18 recommended method is consistent with the SRM statute MCL 460.6w and the
19 cost-of-service statute MCL 460.11(1).
20

21 I am not a lawyer, and in its brief Energy Michigan will address the legal issues involved
22 in determining an equitable and accurate SRM Charge, including any true-up, while at the
23 same time adhering to MCL 460.6w and MCL 460.11(1). As an expert in the field of

1 electric regulation, I can advise the Commission on the operational meaning and effects of
2 the plain words in the statutes and the operational flexibility that those words imply for the
3 Commission to implement a workable true-up method.

4
5 **Introduction**

6
7 **Q. How is your testimony addressing the "true-up" of the SRM Charge organized?**

8 A. There are five aspects:

9 A. First, I will explain the function of a "true-up" within the context of the statutory
10 SRM Charge.

11 B. Next, it will be useful to specify the terminology that I will use, to simplify the
12 discussion and to reduce confusion, as other parties may address the same true-up
13 issue with different terminology.

14 C. Then, I will summarize the history of the SRM Charges, as well as the "true-ups"
15 that the Commission has implemented for DTE Electric, the only company that
16 has implemented a true up, which can illustrate the issues addressed here.

17 D. I will explain the flaws of the current true-up method.

18 E. Finally, I will propose a straightforward and accurate alternative method for the
19 Commission to implement an SRM Charge true-up that is workable, timely,
20 accurate, and equitable for both the utility and all its customer.

A. SRM Charge -- Context and Function of True-Up

Q. How does the SRM statute specify the determination of the SRM Capacity Charge?

A. Section 6w of Public Act 341 of 2016 describes how the SRM Capacity Charge should be calculated and lists the factors to include or consider. The statute assigns to the Commission the responsibility to implement various aspects of the SRM statute.

The MCL 460.6w(3) statute specifies two categories of subtractions in determining capacity costs that are to be included in the SRM Capacity Charge calculation. The first category is simply "non-capacity" costs that are included in electric generation costs, and the second category represents the market value of the energy and electric services that the electric generation can produce. The statute states:

The commission shall do both of the following [. . .]:

(a) For the applicable term of the capacity charge, include the capacity-related generation costs included in the utility's base rates, surcharges, and power supply cost recovery factors, regardless of whether those costs result from utility ownership of the capacity resources or the purchase or lease of the capacity resource from a third party.

(b) For the applicable term of the capacity charge, subtract all non-capacity-related electric generation costs, including, but not limited to, costs previously set for recovery through net stranded cost recovery and securitization ***and*** the projected revenues, net of projected fuel costs, from all of the following:

- (i) all energy market sales.
- (ii) off-system energy sales.
- (iii) ancillary services sales.
- (iv) energy sales under unit-specific bilateral contracts.

[MCL 460.6w(3)(a)&(b), emphasis added.]

1

2 The "projected revenues net of projected fuel costs" listed in the SRM statute in (b) above
3 are commonly referred to as "offsets" in discussions of SRM determinations.

4

5 **Q. What is the function of the "offsets"?**

6 A. The offsets capture the inherent market value of the type of generation that the utility
7 operates, which value is separate from the investment costs and non-capacity operating
8 costs. For example, a nuclear plant may have very high investment costs in order to
9 produce electric energy very cheaply. Thus the market value of that cheap energy would
10 be high -- market energy sales price less low fuel cost to produce. If a party is to pay a
11 high SRM Charge for capacity for the nuclear plant, reflecting high investment costs,
12 then it is equitable that the party also get the true benefit of the market value of the
13 energy produced from that plant by way of offset. In contrast, a gas-fired peaker would
14 have a relatively low investment cost, and high fuel cost. Therefore if a party is to pay a
15 low SRM Charge for the capacity of the peaker, then it is equitable that the party get the
16 true benefit of the market value of the energy produced from the peaker, which will be
17 lower than that for the nuclear plant. The function of the offsets is to quantify the market
18 value.

19

20 **Q. How does a "true-up" come into play in the SRM Charge?**

21 A. The "capacity-related electric generation costs" and the "non-capacity-related electric
22 generation costs" are determined by the Commission in a rate case, which is typically for
23 a future test year, based on embedded costs. The revenues from the market price of the

1 energy and other electric services are not known for that future test year, and therefore they
2 are estimated -- "projected" in the words of the statute. Similarly, the fuel cost associated
3 with the projected energy production depends on the volume of future energy produced,
4 and therefore fuel costs that are expended to capture the market value of energy sales have
5 to be estimated also.

6
7 Therefore, if the SRM Charge is to represent the true value of the "offsets," then the actual
8 market revenues and actual fuel costs have to be used, and these actual revenues and costs
9 are not known until the future period passes. In short, the true-up is intended to help ensure
10 that neither the utility collecting the SRM Charge nor a customer paying the SRM Charge
11 should be at risk to forecast error of the projection, especially since the "offsets" are worth
12 hundreds of millions of dollars.

13
14 **Q. What does the statute say about a "true-up" of projections to actuals?**

15 The 6w statute continues:

16 (4) The Commission shall **provide** for a true-up mechanism that results in a utility
17 charge or credit for the difference between the projected net revenues described in
18 subsection (3) and the actual net revenues reflected in the capacity charge. The
19 true-up shall be **reflected** in the capacity charge in the subsequent year. The
20 methodology used to set the capacity charge shall be the same methodology used
21 in the true-up for the applicable planning year.

22 *[MCL 460.6w(4), emphasis added.]*
23

24 So the statutory process says to use projections initially, but later replace the projected
25 amounts with the actual values for market priced sales and fuel, and "true up" the SRM

1 Charge paid to the utility by the customer. This eliminates the risk of forecast error for
2 both the utility and the customer.

3
4 The statute also gives some flexibility to the Commission in administering the true-up. The
5 statute does not prescribe a specific calculation method, but rather allows the Commission
6 to "*provide for*" a true-up and to have the true-up be "*reflected*" in the capacity charge.

7
8 **Q. Is the true-up concept workable?**

9 A. The true-up is workable as a concept, but as expressed in the statute it has flaws which lead
10 to erroneous results; and the mechanics of the implementation of the true up in the few
11 cases it has been applied has not fixed the errors. I will explain both later in my testimony.

12
13 **Q. What is the overall concept of the true-up process?**

14 A. The overall concept of the true-up process is that a customer paying the SRM Charge
15 initially is assessed a charge according to the capacity and non-capacity costs determined
16 in a rate case, less a credit -- the offsets -- determined by a forecast of energy market sales
17 and other electric services net of fuel.

18
19 After the forecast period has passed, the credit is recalculated using actual energy market
20 sales net of actual fuel, and then the SRM Charge is recalculated using the difference
21 between forecast market sales net of fuel and actual market sales net of fuel.

1 Practically, the "true-up" should be the difference between what the customer initially paid
2 according the SRM Charge with forecast sales and fuel versus the SRM Charge
3 recalculated with actual sales and fuel. That difference could be either an additional
4 payment by the customer to the utility or a refund by the utility to the customer.

5
6 Exhibit EM-2 (AJZ-2), line 23, illustrates the initial SRM Charge using projected sales and
7 fuel and the final SRM Charge using actual sales and fuel. The difference -- \$40 in the
8 example -- is the true-up amount.

9
10 **Q. Do the values and the capacity calculation determined in the rate case portion of the**
11 **SRM Charge change in the actual year?**

12 A. No, the capacity calculation from the rate case remains the same for both (i) the initial SRM
13 Charge that uses projected values for offsets and (ii) the final SRM Charge that uses actual
14 values for offsets. Lines 3-8 on Exhibit EM-2 (AJZ-2) illustrate that the values from the
15 rate case stay the same. Only the value of the offsets changes, as shown on lines 11-18 of
16 the exhibit.

17
18 **Q. What is the function of the values of the offsets for the projected year?**

19 A. The values of the offsets for the projected year are simply a proxy for the actual values that
20 will come later. The projected year functions as a reasonable forecast such that the SRM
21 Charge initially paid will be reasonably close to the final SRM Charge after the true up.

1 The projected values do not have to be the same as the rate case values. In this proceeding,
2 U-21870, the rate case values are from the embedded cost-of-service modeling for
3 Production costs for the test year of 12 months ending April 30, 2027.¹ The projected
4 values -- the forecast of actuals -- can be based on a difference source. In this proceeding,
5 the projected values come from various time periods and sources, including the test year,
6 calendar 2024, and other historical values.² .
7

8 **Q. Are the fuel costs netted out in the calculation of the projected offsets the same as the**
9 **fuel costs used in the Production cost of service?**

10 A. In this case, U-21870, the projected fuel costs for the offsets calculation are the "forecasted
11 variable fuel costs associated with the volume of Energy Market Sales as extracted from
12 the Company's forecast of power supply costs for the test year."³ Although Consumer
13 Energy uses the fuel costs for the test year in the projected offsets calculation, there is no
14 need for them to be the same. The projected fuel functions merely as a forecast for the
15 offset calculation. Projected fuel will be replaced later by actual fuel during the true-up
16 process. Exhibit EM-2 (AJZ-2), line 16, illustrates this. The fuel from the cost-of-service
17 in the rate case -- and the component of the SRM Charge determined by that cost-of-service

¹ See the direct testimony of Ms. Emily A. Davis, page 20, line 5, to page 21, line 1; and Exhibit A-87.

² See the direct testimony of Ms. Megan L. Metz, page 13, line 15, to page 14, line 4; and Exhibit A-160.

³ Ms. Metz, direct testimony, page 14, lines 2-4; and Exhibit A-160, page 1 of 3, line 24, column (o).

1 -- will not change during the true-up process. The fuel values used for the projected offsets
2 will change, to be replace by actual fuel values.

3
4 The capacity cost component of the SRM Charge determined by the rate case cost-of-
5 service is not affected by whatever method is used to forecast energy market sales net of
6 fuel for the offsets -- which method in this case comes from a variety of sources -- nor is
7 it affected by the later outcome of actual energy market sales net of actual fuel. However,
8 a mix up of terminology can occur -- mixing up "fuel" for determination of embedded cost
9 rate case capacity with "fuel" for forecast offsets. I will address this further, later in my
10 testimony.

11
12 **B. SRM Terminology**

13
14 **Q. Why is terminology regarding the State Reliability Mechanism important?**

15 A. Confusion about terminology and processes stems from various causes. The SRM statute
16 itself has several flaws -- based on outdated assumptions -- that make it at odds with the
17 current resource adequacy processes of the Midwest ISO ("MISO"). The SRM statute does
18 not recognize that in 2005 MISO began dispatching all power plants to serve all loads.
19 Thus, the SRM statute was obsolete when it was enacted in 2016. The statute also does
20 not recognize the effects of MISO's implementation of the annual Planning Reserve
21 Auction for capacity in 2013. And it became more obsolete in 2023 when MISO changed
22 its capacity requirements from annual to quarterly. There are a number of other flaws,
23 which I have discussed in previous case testimony. In this proceeding U-21860, I will

1 focus on the true-up aspect of the SRM statute as implemented by the Commission and its
2 conflict with the cost-of-service statute MCL 460.11(1).
3

4 A second cause that creates confusion is the subtraction of costs, whether from non-
5 capacity costs or credits or "netting" of costs in the credits. From simple arithmetic,
6 subtraction of a negative becomes a positive addition, and this can create some ambiguity
7 in the discussion of "true-ups."
8

9 **Q What terminology will you use?**

10 A. I will use the terminology as follows:

11 **SRM Charge** -- The State Reliability Mechanism Capacity Charge applied to a
12 customer if the Load Serving Entity of that customer does not demonstrate
13 sufficient capacity to the Commission, under the Commission's implementation
14 rules for MCL 460.6w.
15

16 The SRM Charge refers to the entire amount to be paid, including both (i) the rate
17 case capacity determination from the costs of service and (ii) the credit for energy
18 market sales and other electrical services net of fuel, whether that credit is due to
19 projected values or actual values.
20

21
22 **Energy Market Sales** -- The revenue in aggregate from the four credit components
23 in MCL 460.6w(3)(b): (i) all energy market sales, (ii) off-system sales, (iii)
24 ancillary service sales, (iv) energy sales under unit-specific bilateral sales.
25

26 Although the tradition in the electric industry is that "sales" refers to energy and
27 "revenues" refers to dollars, it will be much simpler to call the value of all of the
28 above in aggregate "energy market sales."
29

30
31 **Net of Fuel** -- The subtraction of the cost of fuel from Energy Market Sales, where
32 the cost is attributable to the production of any of the four credit components of
33 Energy Market Sales above.
34

1 What ought to be included under "fuel" has been controversial in previous cases.
2 The SRM statute specifies, unequivocally, "fuel." By "fuel" I will mean only "fuel"
3 itself -- not "fuel-related" or "imputed fuel" or "variable purchased power costs" or
4 anything else.

5
6
7 **True-Up Process** -- The "mechanism" called for by Section 6w(4) and provided
8 by the Commission by which a customer that is initially billed an SRM Charge that
9 includes projected energy market sales net of projected fuel has its billing adjusted
10 to match the SRM Charge that includes actual energy market sales net of actual
11 fuel.

12
13 Customer pays A, should pay B, and the "true-up" process is the method to get from
14 A to B. If the customer does not end up paying B, then it is not a correct true-up.

15
16
17 **True-Up** -- An adjustment of the component in the SRM Charge labeled in Section
18 6w(4) as "projected revenues net of projected fuel costs" for the difference between
19 projected values and actual values. As noted in the definition of Energy Market
20 Sales above, in this testimony the term "energy market sales" will refer to the
21 revenue from the four credit components. The SRM statute specifies a true-up for
22 that component only, not the component of the costs-of-service capacity value.

23
24 Again, the true up applies only to energy sales revenue net of fuel costs, not to the
25 entire SRM Charge. This is a useful distinction. As explained previously in my
26 testimony, there is no change in the cost-of-service capacity value in the true-up
27 process, no matter what the projected values are or the actual values are.

28
29
30 **Customer** -- The SRM statute applies the SRM Charge to "load," which
31 traditionally means the amount of power flow or the impedance in a system or
32 circuit. For implementation of the statute, the Commission has interpreted "load"
33 to mean "individual retail customer." Using "customer" will simplify the discussion
34 here.

35
36
37 **Reconciliation** -- I will not use the word "reconciliation" as a substitute for "true-
38 up." Although "reconciliation" has been used in previous SRM Charge cases as a
39 synonym for "true-up," the SRM statute says "true-up," and this is a clearer vision
40 of what is happening -- customer pays A, should pay B, and "true-up" is the method
41 to get from A to B. "Reconciliation" could mistakenly be taken to mean that the
42 only thing that is being done is explaining the difference between A and B.

C. History of SRM Charges and True-Ups

Q. How has the Commission established SRM charges since the enactment of the State Reliability Mechanism in 2016?

A. There are six entities that have established an SRM Charge, including Consumers Energy.⁴ The Commission initiated an original case for each entity and then rendered a decision for each in 2017 and 2018. Energy Michigan participated in the Consumers Energy original case U-18239 and the DTE Electric original case U-18248.

Since that time, the Commission has regularly reviewed the various SRM charges, in rate cases, or in settlements, or in separate case reviews. On the Commission's web site case library, I found 39 cases establishing, modifying, or continuing the SRM charges of the six entities, including the six original cases. Exhibit EM-3 (AJZ-3) shows a chronological list of case orders that include SRM charges, showing the date of the order, the case number, the entity involved, and the SRM Charge. Also included in the exhibit in column (e) is whether or not that particular case and order included a true-up of the projected energy market sales revenue net of fuel from a previous SRM Charge. The following table summarizes the results.

⁴ Consumers Energy, DTE Electric, Upper Michigan Energy Resources (UMERC), Upper Peninsula Power Company (UPPCO), Cloverland Electric Cooperative, and Indiana Michigan Power.

Table 1. Summary of Exhibit EM-3 (AJZ-3)

	Total SRM Cases ⁵	SRM Cases w/true-up
Consumers Energy	9	0
DTE Electric	8	4 ⁶
UMERC	9	0
UPPCO	7	0
Indiana Michigan	3	0
Cloverland	3	0
Total	39	4

Q. What do you infer from the information on Exhibit EM-3 (AJZ-3)?

A. The information shows that the reviews of the SRM Charges have been consistent and equitable for all the six entities -- regular reviews and resettings in 39 cases. The exhibit shows nine cases for Consumers Energy, none of which included a true-up (highlighted in green), one of which was the original case U-18239 which of course would not have included a true up from a previous case. Cases that include true-ups are scarce. There have been only four true-ups -- all for DTE Electric, highlighted in yellow on Exhibit EM-3 (AJZ-3). Out of eight cases setting an SRM Capacity Charge for DTE, only four were trued up.

⁵ This includes the original case for each of the six companies.

⁶ Two of the DTE true-up cases, U-20836 and U-21297, were for the same SRM Charge that was set in U-20561.

1 **Q. Do any of the four DTE Electric cases true up the energy market sales net of fuel that**
2 **was projected in the preceding case that set an SRM Charge?**

3 A. Since Consumers Energy's SRM Capacity Charge included no true-ups in all of its
4 preceding nine SRM case, we have to look at DTE Electric for some of the implementation
5 processes. None of the four DTE cases that include true-ups deal with the immediately
6 preceding case that set an SRM Charge. Three DTE SRM Charges cases were later trued
7 up, one of which was trued up in two later cases, and none of the true-ups were done in
8 succeeding SRM cases, or in the subsequent years, as the SRM statute specifies, "The true-
9 up shall be reflected in the capacity charge *in the subsequent year*."⁷

10
11 **Q. In your observation, is there a reason why none of the four DTE true-ups reflect the**
12 **immediate prior SRM Charge case?**

13 A. Yes. The sequence of cases and order dates point to an obvious flaw in the SRM statute
14 specifying true ups: the cases that set an SRM Charge based on projected energy market
15 sales net of fuel and the cases that true up the projected values to actual energy market sales
16 net of actual fuel take time, significant amounts of time. The setting and true-up are not
17 instantaneous. An SRM Charge is set at the date of the final order in a case, and the next
18 setting is at the time of a final order in the next case, which may be a year or more away,
19 not at the time of the filing of the next case.

20

⁷ MCL 460.6w(4) (emphasis added).

1 Consequently in this case U-21870, filed on May 28, 2025, it would not make sense for a
2 true up to be proposed for the outcome of the immediately prior setting of the SRM Charge,
3 which occurred in the final order for U-21585 on March 21, 2025. Nor would it make
4 sense to true up an SRM Charge that was set two cases prior. It's as if the drafters of PA
5 341 envisioned a PSCR-type process, where every year there is a new PSCR adjustment
6 factor, yet not considering that a PSCR Plan is filed months ahead of the planned year and
7 that a PSCR reconciliation takes months after the end of the plan year. Thus, the statutory
8 true-up process has an inherent timing flaw.

9
10 **D. Flaws in the Formulaic True-Up of Energy Market Sales Net of Fuel**

11
12 **Q. You have described a timing flaw in the SRM statute. How does this flaw affect the**
13 **validity of a true-up of energy market sales net of fuel for the utility and the customer?**

14 **A.** The timing flaw in the SRM statute, coupled with the current formulaic method for true-
15 ups that has been implemented in all four of the SRM Charge cases that have included a
16 true-up so far, results in each of the true-ups being in error. This will continue into the
17 future as long as the present true-up method is applied -- that is, all future true-ups using
18 the present method will be in error. Consequently, neither the utility nor the customer will
19 be treated fairly under the present true-up method.

1 **Q. What is the basic difficulty?**

2 A. Under the present true-up method, the customer and the utility can be trued up only if the
3 customer that pays an SRM Charge in one year also pays an SRM charge determined in a
4 later year. But then the later SRM Charge also has to be trued up.

5

6 **Q. How does the flaw in timing affect the customer and the utility?**

7 A. The flaw in the timing of the present SRM true-up method -- as proposed in this case by
8 Consumers Energy and as implemented in the four DTE Electric cases out of 39 SRM cases
9 total -- results in the present true-up method being contrary to cost-of-service principles
10 and unfair to both the utility and the customer. There is a better way to implement a true-
11 up that is fair to both the utility and the customers, as I will recommend later in my
12 testimony.

13

14 **Q. Would you explain?**

15 A. As stated previously, under the present true-up method the customer and the utility can be
16 trued up (for a difference between initially projected "offsets" and later actual values of the
17 offsets) only if the customer that pays an SRM Charge in one year also pays an SRM charge
18 determined in a later year. But if the customer pays the SRM charge also in a later year,
19 then that later charge would not get trued up until a still later case. The result of the timing
20 flaw in the SRM statute is that SRM Charges and true-ups end up infinitely pancaked.

21

22

1 **Q. Would you give an example?**

2 A. Yes, an example will make the current complex true-up process easier to envision. Since
3 Consumers Energy has never previously had a true-up in any of its nine previous SRM
4 cases, the example will have to be explained in words.

5
6 Looking at three consecutive time periods -- A, B, and C -- and at the SRM Capacity
7 Charge in each period can show the errors in the present true-up process.

8

9 **A. *Charge in period A:***

- 10 • Suppose in time period A, a customer is assessed SRM Charge A.
- 11 • That charge is incorrect because it includes proxy projected values for
12 the offsets in place of actual values, which are unknown at the time
13 (but will later be substituted in the true-up).
- 14 • Consequently, the customer does not pay, nor does the utility collect,
15 the correct amount. The projected values for the offsets must be trued
16 up later.

17

18 **B. *True-up plus charge in period B:***

- 19 • In the present implementation method, after time period A, in the
20 following time period B, SRM Charge B includes the true-up for SRM
21 Charge A.
- 22 • So in order for the customer to receive the correct charge for time
23 period A (and the utility to collect the correct payment), the customer

1 must also be assessed SRM Charge B, which includes the true-up for
2 time period A.

- 3
4 • But SRM Charge B includes projected offsets also, which later have to
5 be trued up.

- 6 • So while the customer is trued up to actuals for time period A, the
7 customer is also paying an estimated, projected amount for SRM
8 Charge B, which is an incorrect charge unless and until SRM Charge
9 B is trued up later.

- 10 • Since SRM Charge B is trued up in the determination of SRM Charge
11 C, the customer will not be trued up for SRM Charge B unless the
12 customer is subject to SRM Charge C in time period C.

- 13
14 • If a different customer is paying SRM Charge B in time period B for
15 the first time, then that customer is getting the effect of a true up for
16 SRM Charge A, which that customer was not subject to, and therefore
17 is getting an erroneous total charge, as is the utility.

18
19 **C. *True up plus charge in period C:***

- 20 • If the customer that was charged in time periods A and B is not
21 assessed SRM Charge C in time period C, then the customer foregoes
22 the proper true up for SRM Charge B, and both the customer and the
23 utility pay and collect the wrong total amount.

1

2

- If the customer that was charged in time period A and B is assessed SRM Charge C in time period C, then the situation is similar to time period B, where the customer receives the correct true up from past charges but also receives an incorrect charge for time period C unless and until the customer also receives the true up for SRM Charge C, which will not occur until time period D when the true up for SRM Charge C will be included in SRM Charge D.

3

4

5

6

7

8

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10

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12

13

And so it goes. The present true-up method has not been correct in the past, is not now correct, and will never be correct.

14

15

16

Q. In the preceding examples, what if a true-up amount in one time period is reversed, or backed out, of the next time period?

17

18

A. If "backing out" the previous true-up, then the following situation occurs:

19

- Suppose a customer is subject to SRM Charges B and C, but not A. Thus the customer should not be affected by the true up for SRM Charge A.

20

21

- But SRM Charge B includes the true-up for SRM Charge A, and therefore if the customer is paying SRM Charge B, the customer is affected by the true up to SRM Charge A.

An attempted remedy might be to back out the true-up for SRM Charge A that was included in SRM Charge B, by reversing it in SRM Charge C. The intent would be that a customer who is subject to SRM Charges B and C should see no effect from SRM Charge A -- that is, the customer would receive the SRM Charge A true up in time period B but then see a reversal in time period C, such that the net amount of the true-up for SRM Charge A would be zero.

This attempted remedy merely produces more errors:

- First, a customer subject only to SRM Charge C does not receive the correct charge because SRM charge C is affected by the reversal of the true-up for SRM Charge A,
- Second, a customer subject to SRM Charge A and SRM Charge C receives the reversal of the true-up for time period A, not the correct true-up for time period A, which occurs via SRM Charge B in time period B.

1 **Q. What conclusion can be made from the example?**

2 A. The example shows that under the present true-up method no matter what time period or
3 combination of time periods a customer may pay the SRM Capacity Charge, the total SRM
4 Capacity Charge the customer pays and the utility collects is always in error:

- 5 • If a customer pays the SRM Charge only in one of the three time periods -- A,
6 B, or C separately -- the total SRM Charge is in error.
- 7 • If a customer pays the SRM Charge in two of the three periods -- A and B, B
8 and C, or A and C -- the total SRM Charge is in error.
- 9 • If a customer pays the SRM Charge in all three periods -- A and B and C --the
10 total SRM Charge is in error.

11

12 There is no situation under the present true-up method where the customer pays and the
13 utility collects the amount as specified in the SRM statute MCL 460.6w.

14

15 **Q. How does this affect compliance with the cost-of-service statute MCL 460.11(1)?**

16 A. Even under the assumption that the SRM Capacity Charge defines the cost of service (and
17 this assumption has been debated in previous cases, but will not be argued here), the present
18 true-up method charges customers and compensates the utility an amount different from
19 the defined amount in every situation. Therefore, the present true-up method cannot be
20 anything other than in conflict with the cost-of-service statute MCL 460.11(1). I will
21 address this also later in this testimony.

22

23 There are solutions, as will be explained in the next section.

E. True-Up Recommendations

Workable, Timely, Accurate, Equitable

Q. What is the current situation regarding paying SRM Charges and settling true-ups?

A. The implementation of SRM Charges began in 2017. To date, eight years later in 2025, no entity has been assessed an SRM Charge. At present, all load serving entities have demonstrated sufficient capacity according to the Commission's rules under PA 341 for the next four years. If an entity is assessed an SRM Charge, the soonest that can reasonably occur is five years from now, and a true up process for such a charge would be at least one year later, or six years from now. There is no urgency to continue the current faulty formulaic true-up method for the next six years.

Q. What is the advice of stakeholders who would be involved in paying and truing up an SRM Charge?

A. Both the two largest utilities in the state, Consumers Energy and DTE Electric, have stated that there is no need to calculate a true up until someone pays the SRM Charge.

[Consumers Energy]

Q. Does Consumers Energy Agree that Section 6w(4) of PA 341 requires a true-up mechanism for SRM capacity charges?

A. Yes. Should the Company ever impose an SRM capacity charge and actually collect revenue from this charge, the Company will include a true-up calculation in its next-filed SRM capacity charge calculation as required by the statute.⁸

⁸ Case No. U-21585, rebuttal testimony of Ms. Megan L. Metz, page 2, lines 3-7. Emphasis added.

1
2
3 *[DTE Electric]*

4 **Q23. How does the Company [DTE Electric] intend to handle any**
5 **reconciliation of previous year variance of wholesale energy sales revenue net**
6 **of fuel costs?**

7
8 A23. The Company currently has no electric choice customers being assessed a
9 capacity charge, thus no reconciliation with any customers has been previously
10 done. The Company files a reconciliation exhibit in the annual PSCR
11 Reconciliation case that would be used for any reconciliation adjustment if a
12 customer were to be charged the SRM.⁹
13
14

15 Energy Michigan -- speaking for Alternative Electric Suppliers and the interests of their
16 customers who would pay the SRM Charge -- agrees with the views of DTE and
17 Consumers Energy that there is no need for implementing an ongoing true-up process until
18 someone actually pays an SRM Charge. Therefore, the Commission has time to deliberate
19 and enact reforms of the methodology before applying it again.
20

21 **Q. Does the Commission have the authority to change the true-up process specified in**
22 **the SRM statute?**

23 A. That is a legal question that Energy Michigan will address in its brief. Practically, from a
24 common regulatory-practice point of view, the Commission has a degree of flexibility in
25 exactly how it can implement a true-up process, for several reasons.
26

⁹ Case No. U-21534, direct testimony of Mr. Shaun D. Burgdorf, page 11, line 21, to page 12, line 2. Emphasis added.

1 ***Flexible Statute:*** First, as noted previously, the statute itself indicates some flexibility for
2 the Commission:

3 (4) The Commission shall **provide** for a true-up mechanism that results in a utility
4 charge or credit for the difference between the projected net revenues described in
5 subsection (3) and the actual net revenues reflected in the capacity charge. The
6 true-up shall be **reflected** in the capacity charge in the subsequent year.

7
8 The **methodology** used to set the capacity charge shall be the same methodology
9 used in the true-up for the applicable planning year.¹⁰

10
11
12
13 "Provide" and "reflected" allow a lot of room for workable methods; and the
14 "methodology" is already the same for how projected and actual offsets are worked into
15 the calculation of the SRM Charge, as is shown on Exhibit EM-2 (AJZ-2) and discussed
16 previously in my testimony. So there is no single prescription that must be followed, but
17 rather room for various methods other than the present formulaic method.

18
19 ***Cost of Service Statute:*** The Commission is also guided by the cost-of-service statute,
20 MCL 460.11(1).

21 Except as otherwise provided in this subsection, the commission shall ensure the
22 establishment of electric rates equal to the cost of providing service to each
23 customer class. In establishing cost of service rates, the commission shall ensure
24 that each class, or sub-class, is assessed for its fair and equitable use of the electric
25 grid.¹¹

¹⁰ MCL 460.6w(4). Emphasis added.

¹¹ MCL 460.11(1). Emphasis added.

1 Recognizing the cost of service requirements can help establish a true-up process that does
2 not charge customers or the utility inaccurate amounts just for carrying over retroactive
3 true-ups for time periods where no service is being provided. "Cost of service" is a
4 principle of regulating rates, not simply a computerized equation.

5
6 ***Proven Past Flexibility:*** Regarding setting a workable and fair SRM Charge, the
7 Commission has already recognized (apart from including a true-up in only 4 of 39 SRM
8 cases) that it has the ability to exercise practical sense to implement something that works.
9 In the Indiana Michigan rate case that set I&M's original SRM Charge, the Commission
10 declared:

11 The Commission agrees with the company that nothing in Act 341 requires that
12 I&M's capacity rate be set using the mechanism set forth in the statute.

13
14 Although the Commission notes that the capacity charge methodology set forth [in]
15 Section 6w(3) may not directly apply to I&M, subsections (a) and (b) of Section
16 6w(3) provide guidance to the Commission for determining capacity costs and
17 rates.

18
19 Based on this guidance and the evidence in this case about an equitable and accurate
20 rate for capacity, the Commission finds it appropriate to revisit the methodology
21 approved by the Commission in Case No. U-17032.¹²
22

23 That should be the goal of a true-up process -- "equitable and accurate."
24

¹² Case No. U-18370, order April 12, 2018, page 71. Emphasis added.

Recommendations

Q. What are your recommendations to the Commission?

A. My testimony and exhibits have shown that the present true-up method is inaccurate, unfair to both utility and customer, and has been applied inconsistently in the 39 SRM cases. There is a straightforward remedy, and it has two aspects:

1. Suspend the current formulaic true-up method, in this proceeding.

This is essential. Continuing the current true-up methodology is not just choosing a different administrative path from what is recommended here; rather, it is continuing and prioritizing a known error over the equitable and accurate implementation of a statute. Prolonging an erroneous rate or rate process, or attempting to shore up and implement a statutory interpretation that has fatal flaws, provides no benefit to either customers or utilities. Nor is it necessary to reopen past SRM cases to take this step of suspension to correct the true-up methodology going forward.

Suspension need not harm anyone, particularly for the next six years, which is the earliest that the Commission reasonably would have to address another true-up method. Utilities and AESs see no benefit of a true-up until some party actually pays an SRM Charge, and the soonest that can happen is five years out from now.

1 2. Implement a customer-specific SRM true-up.

2 Apply a customer-specific true-up to any customer that is assessed the SRM
3 Charge, which is triggered only when and if a customer is subject to the SRM
4 Charge. Thus, if at some time in the future a customer does pay the SRM Charge,
5 then that customer has to be trued up, and this can be done on an *ad hoc* basis for
6 that customer without revising present or future SRM Charges. This corrects and
7 simplifies the SRM true-up process and avoids the pancaking of charges and
8 reversals from previous true-ups.

9
10 A simple method for truing up a customer is to determine the difference between
11 what the customer initially paid -- with projected energy market sales net of fuel --
12 compared to what the customer should pay with actual energy market sales net of
13 fuel. Actuals, once they are available, would be substituted for projections in
14 recalculating the SRM Charge, and the customer would be billed for, or refunded,
15 the difference between the two calculated charges. In this manner, both the
16 customer and the utility would be treated fairly, and no "gaming" of high forecasts
17 or low forecasts would be possible. It also eliminates another inherent error of the
18 present formulaic method, which is that the customer does not necessarily have the
19 same MW capacity obligation in two different periods. Further, it fulfills the
20 statutory requirement that the Commission "provide a true-up mechanism," and it
21 would be a mechanism parallel to the determination of the initial SRM Charge.

1 **Q. How would this work, practically?**

2 A. Looking at Exhibit EM-2 (AJZ-2) provides an example. It doesn't matter if the SRM
3 Charge is expressed in total dollars for the utility or in dollars per MW-day billed to the
4 customer.

5
6 In Exhibit EM-2 (AJZ-2), line 25 shows the SRM Charge dollars -- \$450 with the
7 projections of energy market sales net of fuel and \$490 with the actual energy market sales
8 net of fuel. In the end, the customer should pay the value that goes with the \$490.

9
10 Suppose the customer is billed for \$100 under the initial, projected SRM Charge. With the
11 true up, the customer should pay a difference of:

$$\begin{aligned}
 & \$100 \times (\$490/\$450 - 1) \\
 & = 100 \times (1.0889 - 1) \\
 & = \$108.89 - \$100 \\
 & = \$8.89 \quad \text{to be paid by customer to utility.}
 \end{aligned}$$

16
17 The general calculation would be:

$$\begin{aligned}
 & \text{True-up to be paid} = \\
 & = \text{Initial amount paid} \times \left[\frac{(\text{SRM Charge with actuals})}{(\text{SRM Charge with projections})} - 1 \right]
 \end{aligned}$$

22 *If the result is positive, the true-up is additional money to be paid by the*
23 *customer to the utility.*

1 *If the result is negative, the true-up is money to be refunded by the utility to*
2 *the customer.*

3
4 **Q. What are the advantages of this method?**

5 A. The first advantage is that both the customer and the utility are treated equitably and
6 accurately, the Commission's stated principle.

7
8 The second advantage is the customer does not have to pay an SRM Charge in multiple
9 periods just to be trued up for one period.

10
11 The third advantage is that the rates for full-service customers are no longer affected by
12 errors in projecting energy market sales net of fuel.

13
14 A utility's true-up proposal can cause rate instability. Production costs are divided into
15 "capacity" and "non-capacity," where the "capacity" portion of the rates is determined by
16 the statutory SRM Charge specifications including any effects of a true-up, and all other
17 production costs go into the "non-capacity" portion of the rates. For example, in this
18 proceeding, Consumers Energy's on-peak capacity demand price in its common Primary
19 Demand rate (GPD voltage level 3) increases from \$2.23 per kW to \$4.71 in summer and
20 from \$2.07 per kW to \$4.37 in winter, more than doubling the price.¹³ Under the
21 formulaic true-up method, "capacity" and "non-capacity" do not have usable meaning for

¹³ See Consumers Energy Exhibit A-16, Schedule F-3.0, page 13 of 23.

1 rate design if a significant portion of the capacity cost is due to a "true-up" -- that is, due
2 to forecast errors in the projections for the SRM Charge.

3
4 The fourth advantage is that there is no need for pancaking or reversals or re-reversals of
5 previous true ups.

6
7 The fifth advantage is that the customer's MW capacity obligation, which can be different
8 in two different periods, and upon which the SRM Charge to be assessed is based,
9 becomes irrelevant.

10
11 The sixth advantage is that the recalculation of the SRM Charge using the actual energy
12 market sales net of fuel is readily visible, and easily comparable "before" and "after."

13
14 The seventh advantage is that it eliminates any opportunity for "gaming" the SRM
15 Charge either by the utility or by AESs, via skewing projections of offsets up or down.

16
17 **Q. Would the Commission have to order this method immediately?**

18 A. No, not at all. The Commission and interested parties have at least six years to come to
19 agreement, as long as the current formulaic method is suspended. The arithmetic is so
20 simple that I can't see reopening six contested SRM cases to figure it out. Perhaps a
21 settlement document could be filed. Since no one is paying the SRM Charge now and
22 would not pay for the next four years, the Commission does not have to execute a true-up

1 for each utility for each year, but rather "provide for a true-up mechanism" that would be
2 implemented should the need for a true-up arise.

3
4 **Q. If the formulaic true-up method is suspended in this proceeding, how would that**
5 **change the SRM Charge proposed by Consumers Energy?**

6 A. Consumers Energy's calculation of the SRM Charge appears on Exhibit A-87. Exhibit
7 EM-4 (AJZ-4) summarizes the proposed changes.

8
9 The embedded capacity cost from the cost of service would stay the same, shown on
10 Exhibit EM-4 under "Total Capacity Related Cost" on line 7 as \$1,218,747 (000). And
11 the projected energy market sales net of fuel would stay the same, shown on line 18 as
12 \$339,952.

13
14 The true-up adjustment would change to zero. Consumers Energy calls its cumulative
15 total true up adjustment "SRM Reconciliation," shown on line 19 in column (b) as \$ -
16 461,000, and this would change to zero on line 19 in column (c).

17
18 Carrying through the arithmetic on Exhibit EM-4, the "Net Capacity Cost" on line 20
19 would change from \$417,794 in column (b) to \$878,795 in column (c), and the "Capacity
20 Charge (\$/MW-Day" on line 22 would change from the proposed \$116.17 in column (b)
21 to \$244.36 (in column (c)).

22
23 All these changes are shown on Exhibit EM-4.

1

2 Q. Would you recap your testimony?

3 A. Yes. As stated at the beginning of my testimony, my testimony and exhibits have shown
4 three aspects of the present SRM true-up method:

5 • **Implementation Errors:** The present true-up method ends up with the wrong
6 total amount of the SRM Charge being paid by the customer and collected by the
7 utility in each and every situation that it is applied. No matter in which or in how
8 many time periods a customer is assessed the SRM Charge, the total charge is
9 always incorrect.

10

11 • **Cost of Service:** The present true-up method is inconsistent with cost-of-service
12 principles and the cost-of-service statute MCL 460.11(1). In addition, and
13 incorrect charge can never be justified as "following the cost of service."

14

15 • **Workable True-Up:** There is a simple and precise way to implement an equitable
16 and accurate true-up for the SRM Charge, which I recommended and explained,
17 such that neither the customer nor the utility is advantaged or disadvantaged. This
18 recommended method is consistent with the SRM statute MCL 460.6w and the
19 cost-of-service statute MCL 460.11(1).

20

21 Q. Does this conclude your direct testimony?

22 A. Yes, it does.

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 generation and distribution of)
 electricity and for other relief.)
 _____)

Case No. U-21870

REBUTTAL TESTIMONY OF
ALEXANDER J. ZAKEM
ON BEHALF OF
ENERGY MICHIGAN

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

2 A. My name is Alexander J. Zakem, and my business address is 46180 Concord, Plymouth,
3 Michigan 48170.

4
5 **Q. On whose behalf are you testifying in this proceeding?**

6 A. I am testifying on behalf of Energy Michigan.
7

8 **Q. Are you the same Alexander J. Zakem who provided direct testimony in this**
9 **proceeding?**

10 A. Yes, I am.
11

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

13 A. Yes. I am sponsoring one exhibit, Exhibit EM-5 (AJZ-5), entitled "Recommended
14 Changes to SRM Charge Calculation without Formulaic True-Up."
15

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

17 A. In my direct testimony, I recommended (1) that the formulaic true-up method for the State
18 Reliability Mechanism Capacity Charge ("SRM Charge") be suspended until a customer
19 actually pays an SRM Charge and (2) if a customer were to pay an SRM Charge then a
20 true-up would be done for that specific customer.¹ Exhibit EM-4 (AJZ-4) included with

¹ Direct testimony of Alexander J. Zakem, pages 29-30.

1 my direct testimony used Consumers Energy's proposed SRM calculation (from Exhibit
2 A-87) to show how the SRM Charge would be calculated without a true-up.

3
4 In its direct testimony, the Michigan Public Service Commission Staff ("Staff") likewise
5 recommended:

6 "Staff recommends the Commission determine that a true-up is only necessary if a
7 customer is actually subject to the capacity charge and there is actual revenue to
8 reconcile."²
9

10 The Staff provided a table showing the values of the SRM Charge with and without a true-
11 up included,³ and I agree with the values (but for minor rounding). At the same time, Staff's
12 Exhibit S-6, Schedule F-1.5, which shows the calculation of the SRM Charge using Staff's
13 various proposed production costs and offsets still includes and uses the true-up value of
14 \$461,000 (000).

15
16 The purpose of my testimony is simply to clarify via my Exhibit EM-5 (AJZ-5) to show
17 how the Staff's Exhibit S-6, Schedule F-1.5, would be revised to determine the SRM
18 Charge without the true-up.

² Direct testimony of Mr. Mark J. Pung, page 9, line 15, to page 10, line 2.

³ Mr. Pung direct testimony, page 9.

1 **Q. If the formulaic true-up method is suspended in this proceeding, how would the SRM**
2 **Charge proposed by the Staff be calculated?**

3 A. Exhibit EM-5 (AJZ-5) summarizes the proposed changes, using the Staff's values for
4 Production costs, Non-Capacity Costs, and Offsets.

5
6 The embedded capacity cost from the cost of service would stay the same, shown on
7 Exhibit EM-5 (AJZ-5) under "Total Capacity Related Cost" on line 10 as \$1,218,747 (000).
8 And the projected offsets net of fuel would stay the same, shown on line 18 as \$339,952.

9
10 The true-up adjustment would change to zero. The cumulative total true up adjustment
11 "SRM Reconciliation," shown on line 19 in column (b) as \$ - 461,000, would change to
12 zero on line 19 in column (c).

13
14 Carrying through the arithmetic on Exhibit EM-5 (AJZ-5), the "Net Capacity Cost" on line
15 20 would change from \$402,762 in column (b) to \$863,762 in column (c), and the
16 "Capacity Charge (\$/MW-Day)" on line 22 would change from Staff's proposed \$111.99
17 in column (b) with a true-up to \$240.18 in column (c) without a true-up.

18
19 All these changes are shown on Exhibit EM-5 (AJZ-5).

20
21 In short, the resulting recalculated SRM Charge in Exhibit EM-5 (AJZ-5) on line 22,
22 column (c), of \$240.18 would be the SRM Charge determined from the Staff's proposed
23 production costs and offsets in Exhibit S-6, Schedule F1.5, but without a true-up.

1

2 **Q. Does your calculated value of \$240.18 match the Staff's proposed value?**

3 A. Yes, they match but for a minor rounding difference of \$0.10. Staff's proposed value
4 shown in its direct testimony is \$240.08,⁴ and the calculation in Exhibit EM-5 (AJZ-5) is
5 \$240.18

6

7 Energy Michigan is not submitting a position on other values used in the determination of
8 Production costs, Non-Capacity costs, or Offsets except for the elimination of the true-up
9 value of \$461,000 on Exhibit EM-5 (AJZ-5).

10

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

12 A. Yes, it does.

⁴ See Mr. Pung's direct testimony, page 9, table on lines 3-4, row labeled "Capacity Charge per MW-Day," under caption "SRM Capacity: No True-Up," in column labeled "Staff's Case," value \$240.08.

1 MR. OOMS: Thank you. That concludes Energy
2 Michigan's case, Your Honor.

3 JUDGE THOITS: All right. Would you like to
4 continue with Michigan Energy Innovation -- Institute for
5 Energy Innovation Advanced Energy? Is that you?

6 MR. OOMS: That is me, Your Honor. Yes. Thank
7 you. I would appreciate that.

8 JUDGE THOITS: Thank you.

9 MR. OOMS: All right. Then, at this time, and
10 in accordance with the stipulation of the parties to this
11 case, I would move to bind in the testimony of MEIUs three
12 witnesses. Witness Sophia Schuster, witness Brett Sproul,
13 and witness John Albers. I'll take them one at a time as
14 previous have gone. So, that will begin with witness
15 Schuster. Her direct testimony consists of a cover page,
16 a table of contents, and 51 pages of questions and
17 answers. She also filed rebuttal testimony, which
18 consists of a cover page, a table of contents, and 15
19 pages of questions and answers, and she sponsored Exhibits
20 MEIU-1.1 through MEIU-1.4.

21 JUDGE THOITS: And that was both direct and
22 rebuttal testimony, correct?

23 MR. OOMS: Correct, Your Honor.

24 JUDGE THOITS: Are there any objections to the
25 admission of this testimony or these exhibits?

1 Hearing none. The direct and rebuttal testimony
2 of Sophia Schuster is bound into the record, and Exhibits
3 MEIU-1.1 through MEIU-1.4 are admitted.
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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 raise its) rates, amend its rate schedules and rules) governing the distribution and supply of electric) energy, and for miscellaneous accounting) authority.) 	Case No. U-21870	

DIRECT TESTIMONY OF SOPHIA SCHUSTER
ON BEHALF OF
THE MICHIGAN ENERGY INNOVATION BUSINESS COUNCIL,
INSTITUTE FOR ENERGY INNOVATION,
AND
ADVANCED ENERGY UNITED

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1 **I. INTRODUCTION AND QUALIFICATIONS**

2 **Q. State your name, business name and address.**

3 A. My name is Sophia Schuster, and I am a Policy Principal with the Michigan Energy
4 Innovation Business Council (“Michigan EIBC”) and the Institute for Energy Innovation
5 (“IEI”), located at 115 West Allegan Street, Suite 710, Lansing, Michigan 48933.

6
7 **Q. On whose behalf are you appearing in this case?**

8 A. I am appearing here as an expert witness on behalf of Michigan EIBC, IEI, and Advanced
9 Energy United (“United”), collectively referred to as “MEIU.”

10
11 **Q. Summarize your educational background.**

12 A. I have a Master’s in Supply Chain Management and a Master’s in Business Administration
13 from the Pennsylvania State University, conferred in May 2023 and in May 2019,
14 respectively. I also have a Bachelor of Arts degree from Albright College, conferred in
15 May 2012.

16
17 **Q. Summarize your experience in the field of electric utility regulation.**

18 A. Since October 2023, I have served as a Policy Principal at Michigan EIBC and IEI. In this
19 capacity, I have assisted in drafting comments in many non-adjudicated dockets before the
20 Michigan Public Service Commission (“Commission” or “MPSC”). Also in this capacity,
21 I have provided policy expertise, conducted research, and analyzed regulations related to
22 advanced transportation and mobility. My work experience is set forth in detail in my
23 resume, attached as Exhibit MEIU-1.1.

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Q. Summarize your professional development coursework in the field of electric utility regulation.

A. I have completed the following coursework related to electric utility regulation:

- March 2024 - Electric vehicle (“EV”) Charging Infrastructure (Electric Utility Consultants, Inc. (“EUCI”))
- March 2024 - Time of Use (“TOU”) Rate Design: Advantages, Issues, and Challenges (EUCI)
- March 2025 - Accounting and Ratemaking (Michigan State University, Institute of Public Utilities)
- May 2025 - Basics of Electricity and Utility Systems Part 2 (EUCI)

Q. Have you written or supported the writing of testimony or comments in any other utility regulatory proceeding before this Commission?

A. Yes, I have previously written or supported the writing of testimony and comments in the following cases and utility regulatory proceedings:

- U-21860 (DTE Electric Company general electric rate case);
- U-21534 (DTE Electric Company general electric rate case);
- U-21585 (Consumers Energy Company [“Consumers Energy,” “Consumers,” or the “Company”] general electric rate case); and
- U-21492 (Transportation Electrification Plan [“TEP”] filing requirements).

In addition to this work, I have been involved on behalf of Michigan EIBC in multiple workgroup proceedings at the Commission, including those focused on electric vehicle

1 (“EV”) deployment, benefit-cost analyses, Integrated Resource Plan (“IRP”) requirements,
2 and distribution system planning.

3
4 **Q. Please summarize your experiences working with advanced energy companies and**
5 **other key stakeholders on issues related to electric utility regulation.**

6 A. I have served as a Policy Principal at Michigan EIBC and IEI since October 2023. In this
7 role, I have led the organizations’ transportation electrification work. I have led the
8 development and publication of several pieces of transportation electrification research,
9 including a roadmap highlighting key policy opportunities to enable the state’s
10 transportation electrification goals¹ and a report discussing the critical role of the
11 automotive industry to the Michigan economy.² As described above, I have also
12 participated in several workgroups at the Commission and supported the drafting of written
13 comments in a number of non-adjudicated dockets. I also communicate formally and
14 informally with Michigan EIBC member companies about each of these regulatory
15 proceedings to understand how the advanced energy industry is affected. In addition, I
16 participate in several coalitions focused on enabling the state’s advanced mobility goals
17 and facilitating a safe and equitable transition to EVs for Michigan’s drivers and
18 communities, including the Council on Future Mobility and Electrification’s EV Action
19 Team. In this capacity, I communicate formally and informally with coalition members
20 about current regulatory proceedings and how each impacts any shared objectives.

¹ Michigan Energy Innovation Business Council and Clean Fuels Michigan, *Transportation Electrification in Michigan: A Roadmap to State Policy Actions*, October 2024, available at <https://www.mieibc.org/wp-content/uploads/2024/10/Transportation-Electrification-in-Michigan.pdf>.

² Michigan Energy Innovation Business Council, *Legacy, Innovation, and the Race Against China: The Automotive Industry and the Michigan Economy*, May 2025, available at https://www.mieibc.org/wp-content/uploads/2025/05/Auto-Leadership-and-the-Michigan-Economy_MIEIBC.pdf.

1

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

3 A. The purpose of my direct testimony is to express support for certain aspects of the
4 Company's EV proposals as well as describe proposed modifications thereto based on my
5 experiences in the transportation electrification policy space.

6

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

8 A. Yes, I am sponsoring the following exhibits:

9

- Exhibit MEIU-1.1: Résumé of Sophia Schuster, MBA, MSCM

10

- Exhibit MEIU-1.2: Discovery Response MEIU-CE-0039

11

- Exhibit MEIU-1.3: Discovery Response MEIU-CE-0043

12

- Exhibit MEIU-1.4: Discovery Response MEIU-CE-0042

13 **II. TRANSPORTATION ELECTRIFICATION**

14 **A. OVERVIEW OF CONSUMERS ENERGY'S TRANSPORTATION**
15 **ELECTRIFICATION PLAN ("TEP")**
16

17 **Q. Please summarize Consumers Energy's transportation electrification proposals in**
18 **this case.**

19 A. The Company's proposals regarding transportation electrification are presented primarily
20 in the direct testimony of Jeffrey A. Myrom,³ and in the Company's Transportation

³ Direct Testimony of Jeffrey A. Myrom on behalf of Consumers Energy ("Myrom Direct"), Case No. 21870.

1 Electrification Plan 2025 Annual Progress Report (“TEP 2025 annual update”).⁴ The
2 Company describes the load optimization benefits to all customers resulting from increased
3 EV adoption and then details the status of its existing TEP program elements, approved in
4 Case No. U-21585 (the Company’s most recent general electric rate case). The major
5 elements included in the TEP are:

- 6 • *Residential programming*. This includes “educational outreach, time-of-use (“TOU”)
7 rate, and rebate and incentive programs for off-peak charging at Level 2 (“L2”) circuit
8 levels of 50 amps or less” for single-family homes (“SFH”).⁵ Participants accessing a
9 SFH rebate are eligible for up to \$500 (or \$1,000 for low-income (“LI”) customers).
10 To reinforce the desired off-peak charging behavior, participants can also enroll in the
11 company’s TOU rate for which they are eligible to receive a bill credit of \$10 per month
12 for one year.⁶ Additionally, the Company is implementing a referral incentive program
13 and a dual-cord L2 and splitter incentive.⁷

14
15 Residential programming also includes strategic opportunities for multifamily housing
16 (“MFH”) properties that need to add a second service.⁸ Properties where L2 charging
17 cannot be tied to a resident’s meter or parking space are eligible for a rebate of up to

⁴ Consumers Energy, “Transportation Electrification Plan Annual Progress Report 2025,” Case No. U-21538, Filing No. U-21538-007 (June 27, 2025).

⁵ Myrom Direct, p. 6.

⁶ *Ibid.*

⁷ *Id.*, pp. 6-7.

⁸ *Id.*, pp. 7-8.

1 \$7,500 “to add a separate service with at least two plugs powered by 100 amps.”⁹

2 Property owners receive signage and informational materials and can access a TOU bill

3 credit of \$20 per month for one year if at least 80% of charging takes place off-peak;¹⁰

- 4 • *Public programming.* Like its residential programming, the Company’s public L2 and
5 Level 1 (“L1”) efforts include educational outreach, TOU rates, and rebates.¹¹

6 Examples of public programming applications include community chargers, and
7 chargers at hotels and tourism destinations; and

- 8 • *Fleet programming.* The fleet and workplace charging programming focuses on
9 “outreach, TOU rate, and rebate programs for small and medium businesses, local
10 governments, non-profits, and educational institutions to incentivize off-peak
11 charging.”¹² Like MFH properties, fleet and workplace participants are eligible for
12 rebates of up to \$7,500 per two plugs powered by 100 amps.¹³ For L2 chargers in a
13 workplace setting that can also serve the local community outside business hours,
14 participants are eligible for an enhanced rebate of up to \$10,000.¹⁴ A rebate of up to
15 \$15,000 for direct current fast charging (“DCFC”) of up to 50kW per plug is also
16 available to fleet operators with medium- and heavy-duty (“MHD”) vehicles.¹⁵

⁹ *Id.*, p. 7.

¹⁰ *Id.*, p. 8.

¹¹ *Id.*, pp. 8-9.

¹² *Id.*, p. 9.

¹³ *Ibid.*

¹⁴ *Ibid.*

¹⁵ *Id.*, pp. 9-10.

1 The Company is not proposing any cost increases relative to the Company’s most recent
2 general electric rate case (Case No. U-21585), nor is it shifting its focus from its core
3 strategy to optimize off-peak charging.¹⁶ However, the Company does propose several so-
4 called “enhancements” to the TEP programs. These include:

- 5 • A request to allow L2 and L1 rebates across all categories to be used for the installation
6 of an appropriate weatherized and EV-rated National Electric Manufacturers
7 Association (“NEMA”) outlet; and
- 8 • A request to modify its public DCFC rebate pilot.

9
10 **B. EV ADOPTION FORECASTS**

11 **Q. How does Consumers predict that EV sales will grow in the Company’s service**
12 **territory?**

13 A. In his direct testimony, witness Myrom presents a base case and a high case, and reports
14 that

15 EV load growth has been at or above the “500K EV[s]” by 2030 EV
16 scenario utilized in the 2021 Integrated Resource Plan (Case No. U-21090),
17 annual TEP related reports, and prior electric rate cases...The latest data
18 from the Michigan Secretary of State also indicates that a range [of] 470,000
19 to 600,000 EVs by 2030 [is] likely in the Company’s territory.¹⁷
20

21 In a discovery response (Exhibit MEIU-1.2), witness Myrom notes that

22 [t]he base case model tracks historic adoption of EVs in Consumers
23 Energy’s electric territory utilizing actual Michigan Secretary of State
24 (SOS) quarterly data. The model utilizes historic sales trends to predict EV
25 adoption in the near term, and once adoption levels achieve 7% or greater,

¹⁶ *Id.*, p. 12.

¹⁷ *Id.*, p. 11.

1 the projection then approximates the percentage of sales experienced by
2 Norway.
3

4 Witness Myrom goes on to state (Exhibit MEIU-1.2) that

5 [t]he high case incrementally magnifies the base case projection over time
6 to +25%, representing the continuation of cost and range improvements via
7 technology advances, public charging infrastructure improvements, and
8 economies of scale via factory and battery chemistry developments, all
9 contributing to higher levels of EV adoption than the historic Norway
10 pathway.
11

12 Witness Myrom also notes that EV adoption within the Company's service territory does
13 not capture the load growth attributable to EVs driving through its electric territory to reach
14 and stay in popular Michigan tourist destinations.¹⁸ As such, EV load growth is driven not
15 only by EVs adopted within the Company's service territory, but also by drivers traveling
16 through its service territory. Consequently, witness Myrom asserts that total EV load
17 growth is a more appropriate metric than EV adoption for assessing the impact of the
18 Company's TEP programs.¹⁹
19

20 **Q. What is the current state of automotive EV sales in the U.S. and in Michigan?**

21 A. In 2019, nearly 315,000 new light-duty EVs were sold throughout the United States,
22 making up just 1.8% of total vehicle sales at the time.²⁰ Only five years later, new light-
23 duty ("LD") EV sales reached 1.48 million nationwide, marking a 369.8% sales increase
24 between 2019 and 2024 and bringing the number of total new EVs on the road to 6.4

¹⁸ *Id.*, p. 12.

¹⁹ *Ibid.*

²⁰ Atlas Public Policy, *EV Hub - EV Market Dashboard*, July 2025, available at <https://www.atlasevhub.com/market-data/ev-market-dashboard/>.

1 million.²¹ Today, there are nearly 7 million EVs on the road, with EV sales now accounting
2 for almost 10% of automotive sales.²² In Michigan, the market share for EV sales increased
3 year-over-year from 4.4% in the second quarter of 2023 to 11.3% in 2025.²³ Equally
4 remarkable is the growth of the MHD market segment, which grew from about 1,400 new
5 MHD EV purchases in 2021 to 124,000 in 2024 - an astounding 8,800% sales increase.²⁴
6 These trends across the country and in Michigan clearly indicate a steady and accelerating
7 EV adoption growth rate.

8
9 **Q. What impact could the current political and economic climate have on automotive**
10 **sales and EV sales specifically?**

11 A. Since the start of 2025, several federal actions have resulted in increased uncertainty across
12 the automotive industry. These include:

²¹ *Ibid.*

²² *Ibid.*

²³ *Ibid.*

²⁴ *Ibid.*

- 1 • The introduction of a 25% tariff on some imported vehicles,²⁵ as well as tariffs on
- 2 several components critical to vehicle manufacturing, such as steel, aluminum, copper,
- 3 energy, and imported minerals;^{26, 27, 28}
- 4 • The repeal of several tax credits which were part of the Inflation Reduction Act,
- 5 including the 30C Alternative Fuel Vehicle Refueling Property Credit and the 30D
- 6 Clean Vehicle Credit;^{29, 30}
- 7 • The nullification under the Congressional Review Act of EPA Clean Air Act
- 8 preemption waivers for California’s Advanced Clean Cars II;^{31, 32} and

²⁵ Cox Automotive, “Auto Industry Braces for Impact: 25% Tariffs on Imported Vehicles Set to Disrupt Market,” March 2025, available at <https://www.coxautoinc.com/market-insights/auto-industry-braces-for-impact-25-tariffs-on-imported-vehicles-set-to-disrupt-market/>.

²⁶ Brinley, S., S&P Global, “How Tariffs are Affecting the Automotive Industry,” April 2025, available at <https://www.spglobal.com/automotive-insights/en/rapid-impact-analysis/us-auto-tariffs-impact-on-auto-industry>.

²⁷ *MotorTrend*, “How Are Trump's Tariffs Impacting Cars, Costs, and Customers? Japan Gets a Huge Break,” July 2025, available at <https://www.motortrend.com/news/trump-tariffs-trade-war-automotive-industry-impact-developments>.

²⁸ Carpenter, J., “Carpenter: Return of Trump tariffs could impact state’s innovative industries,” *The Detroit News*, February 2025, available at <https://www.detroitnews.com/story/opinion/2025/02/12/carpenter-return-of-trump-tariffscould-impact-states-innovative-industries/78422652007/>.

²⁹ Evergreen Action, “Republican Megabill Is a Disaster for Energy Costs, Jobs, and Clean Energy,” June 2025, available at <https://www.evergreenaction.com/blog/senate-gops-updated-megabill-is-still-a-disaster-for-affordability-jobs-and-clean-energy>.

³⁰ *The Business Times*, “Tesla braces for rough quarters ahead as US ends EV incentives,” July 2025, available at <https://www.businesstimes.com.sg/companies-markets/transport-logistics/tesla-braces-rough-quarters-ahead-us-ends-ev-incentives>.

³¹ Brinley, St., S&P Global, “California's Advanced Clean Cars II ZEV rules under fire,” May 2025, available at <https://www.spglobal.com/automotive-insights/en/blogs/2025/05/california-advanced-clean-cars-zev-rules>.

³² Manescu, L., Sierra Club, “Donald Trump Signs Reversal of State Clean Car Standards, Selling Out Americans to Polluters and Unraveling Clean Air Act Protections,” June 2025, available at <https://www.sierraclub.org/press-releases/2025/06/donald-trump-signs-reversal-state-clean-car-standards-selling-out-americans>.

- 1 • The elimination of civil penalties for automakers failing to meet Corporate Average
2 Fuel Economy (“CAFE”) standards.³³

3

4 **Q. Do you agree with the EV deployment rate predicted by the Company and its**
5 **response to current political and economic conditions?**

6 A. Yes. While there may be a slowdown in EV adoption and automotive manufacturing in the
7 short term, experts agree that EVs represent the future of the industry – both in the United

³³ Sidley, “Congress Eliminates Corporate Average Fuel Economy (CAFE) Penalties for Passenger Cars and Light Trucks,” July 2025, available at <https://environmentalenergybrief.sidley.com/2025/07/08/congress-eliminates-corporate-average-fuel-economy-cafe-penalties-for-passenger-cars-and-light-trucks/>.

1 States and globally.^{34, 35, 36, 37, 38, 39, 40, 41, 42, 43, 44, 45} Global trends clearly indicate stable EV
 2 adoption growth, particularly in European, Southeast Asian, and South American

³⁴ Hertzke, P. et al., McKinsey & Company, “New twists in the electric-vehicle transition: A consumer perspective,” April 2025, available at <https://www.mckinsey.com/features/mckinsey-center-for-future-mobility/our-insights/new-twists-in-the-electric-vehicle-transition-a-consumer-perspective>.

³⁵ Andreoni, M., “The Electric Vehicle Future Is Coming. Just a Little More Slowly,” *The New York Times*, September 2024, available at <https://www.nytimes.com/2024/09/05/climate/electric-vehicle-sales-projections.html>.

³⁶ Ewing, J., “Trump Will Slow, but May Not Stop, the Rise of Electric Vehicles,” *The New York Times*, August 2025, available at <https://www.nytimes.com/2025/08/03/business/trump-electric-vehicles.html>.

³⁷ International Energy Agency, *Global EV Outlook 2024: Trends in electric cars*, March 2025, available at <https://www.iea.org/reports/global-ev-outlook-2024/trends-in-electric-cars>.

³⁸ Domonoske, C., “Trump's pulling a U-turn on EVs, but not much has changed — yet,” *NPR*, January 2025, available at <https://www.npr.org/2025/01/30/nx-s1-5272749/donald-trump-ev-electric-vehicles-subsidies-auto-industry>.

³⁹ Gross, P., “EV Industry will Persist, Experts Say, Despite Trump Cuts,” *Missoula Current*, March 2025, available at <https://missoulacurrent.com/ev-industry-trump/>.

⁴⁰ Rivers, S., “Jim Farley: ‘If We Lose This, We Do Not Have A Future Ford’,” *CarScoops*, July 2025, available at <https://www.carscoops.com/2025/07/jim-farley-if-we-lose-this-we-do-not-have-a-future-ford/>.

⁴¹ Marshall, A., “Ford Is Sticking With an EV Future—With a Boost From Tesla,” *Wired*, March 2025, available at <https://www.wired.com/story/ford-ev-charging-adapters-for-tesla-superchargers/>.

⁴² Jain, S., “Tesla Is Still Selling Glossy Future - GM Just Shipped 111% More EVs,” *Yahoo! Finance*, July 2025, available at <https://finance.yahoo.com/news/tesla-still-selling-glossy-future-150621575.html>.

⁴³ Bassett, A., “Why GM’s CEO is still betting on electric vehicles (and racing),” *The Verge*, July 2025, available at <https://www.theverge.com/gm-general-motors/705320/gm-ceo-mary-barra-interview-ev-cadillac-dei-trump>.

⁴⁴ Chang, J., “Are EVs the Future of GM?,” *Wall Street Journal Podcasts, Tech News Briefing*, June 2025, available at https://www.wsj.com/podcasts/tech-news-briefing/are-evs-the-future-of-gm/4cbe61e3-9159-4d49-9c18-bfe2ba9de618?gaa_at=eafs&gaa_n=ASWzDAjvEtVc0hn7qrtdnsv85q_nER8swRg2lVr4MClaX4jYVWUfzbPRbGHsS4x8Kk%3D&gaa_ts=6887614a&gaa_sig=jSxbs5i7GCMo2ILLHosoQ3ToE4ze447F7ZR5f04QUnNGkSz2tMtm86lOAFpzoOlusdsI24KrW8d3OIkvW-Tw-w%3D%3D.

⁴⁵ Reuss, M., “From Tennessee to Michigan, GM is building a battery-powered future,” *GM News*, July 2025, available at <https://news.gm.com/home.detail.html/Pages/topic/us/en/2025/jul/0714-Tennessee-Michigan-battery-powered-future.html>.

1 markets.^{46, 47} To compete with a burgeoning Chinese EV industry, American automakers
2 will need to continue producing EVs to remain globally competitive.⁴⁸ In addition to
3 automakers' motivation to invest in EV development and production, improved EV

⁴⁶ International Energy Agency, *Global EV Outlook 2024: Trends in electric cars*, March 2025, available at <https://www.iea.org/reports/global-ev-outlook-2024/trends-in-electric-cars>.

⁴⁷ Chang, A. and Bradsher, K., "How China Became the World's Largest Car Exporter," *The New York Times*, November 2024, available at <https://www.nytimes.com/interactive/2024/11/29/business/china-cars-sales-exports.html>.

⁴⁸ Reuters, "China's electric vehicles are around 3-5 years ahead, BYD CEO says," February 2025, available at <https://www.reuters.com/business/autos-transportation/chinas-electric-vehicles-are-around-3-5-years-ahead-byd-ceo-says-2025-02-18/>.

1 range^{49, 50, 51, 52} and price competitiveness,^{53, 54, 55, 56, 57, 58, 59} the growth of the used EV
 2 market,⁶⁰ and supportive state actions^{61, 62, 63} will enable continued EV adoption growth
 3 through this period of political and economic uncertainty at the federal level.

⁴⁹ Elliott, D., World Economic Forum, “5 developments that could make owning an EV more convenient,” October 2024, available at <https://www.weforum.org/stories/2024/10/electric-vehicles-batteries-charging/>.

⁵⁰ Shakir, U., “Heat pumps in EVs are making a big difference in cold-weather driving,” *The Verge*, January 2025, available at <https://www.theverge.com/2025/1/23/24350602/electric-vehicle-heat-pump-better-range-tesla-etron-mustang-mach-e>.

⁵¹ Kothari, S., “Even Affordable EVs Are Getting Solid-State Batteries Now,” *Inside EVs*, July 2025, available at <https://insideevs.com/news/766509/affordable-ev-solid-state-battery-mg4-china/>.

⁵² Ghoshal, A., “BMW promises 30% longer range in upcoming EVs with custom batteries,” *New Atlas*, March 2025, available at <https://newatlas.com/automotive/bmw-longer-range-neue-klasse-ev-batteries/>.

⁵³ Foote, B., “Ford CEO Jim Farley Says Next Gen EVs Will Be Cheaper Than Current Lineup,” *Ford Authority*, June 2025, available at <https://fordauthority.com/2025/06/ford-ceo-jim-farley-says-next-gen-evs-will-be-cheaper-than-current-lineup/>.

⁵⁴ Slowik, P. et al., International Council on Clean Transportation, *Assessment of light-duty electric vehicle costs and consumer benefits in the United States in the 2022–2035 time frame*, October 2022, available at <https://theicct.org/publication/ev-cost-benefits-2035-oct22/>.

⁵⁵ Stoklosa, A., “The Super-Affordable 2027 Chevrolet Bolt EV Is Coming Soon—Very Soon,” *Motortrend*, June 2025, available at <https://www.motortrend.com/news/2027-chevrolet-bolt-everything-you-need-to-know>.

⁵⁶ Banner, J., “The Cheap Tesla Is Almost Here—and We Finally Know What It’ll Look Like,” *Motortrend*, July 2025, available at <https://www.motortrend.com/news/cheap-tesla-model-y-coming-2025>.

⁵⁷ Kothari, S., “General Motors Says New LMR Battery Will Deliver Major Cost Savings,” *Inside EVs*, July 2025, available at <https://insideevs.com/news/766646/gm-lmr-battery-cost-savings-lfp/>.

⁵⁸ GM News, “GM and LG Energy Solution to pioneer LMR battery cell technology,” May 2025, available at <https://news.gm.com/home.detail.html/Pages/news/us/en/2025/may/0513-GM-LG-Energy-Solution-pioneer-LMR-battery-cell-technology.html>.

⁵⁹ Mile, N., “Ford’s Michigan EV battery plant backed by tax credits after political reboot,” *Fox: WFXR*, July 2025, available at <https://www.wfxrtv.com/automotive/fords-michigan-ev-battery-plant-backed-by-tax-credits-after-political-reboot/?nxsparm=9>.

⁶⁰ Toussaint, K., “The first big batch of used EVs will hit the market in 2026. No one knows what’s going to happen,” *Fast Company*, January 2024, available at <https://www.fastcompany.com/91018102/the-first-big-batch-of-used-evs-will-hit-the-market-in-2026-no-one-knows-whats-going-to-happen>.

⁶¹ Department of Environment, Great Lakes, and Energy, “Clean Fuel and Charging Infrastructure Program,” accessed July 2025, available at <https://www.michigan.gov/egle/about/organization/materials-management/energy/rfps-loans/clean-fuel-and-charging-infrastructure-program>.

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Q. Do you expect that the global automotive industry will continue to encourage EV adoption in the short- and long-term?

A. Despite the retraction of federal support in the United States, experts and industry leaders in the global automotive sector still firmly believe that EVs are the future of transportation.^{64, 65} In fact, the 2025 EV Outlook report by Bloomberg New Energy Finance (“BloombergNEF”) finds that EVs will reach 56% of new vehicle sales globally by 2035 and 70% by 2040, which is only a 3% decrease from the previous outlook conducted in 2020.⁶⁶ Furthermore, the same BloombergNEF report indicates that the United States will have just over 35 million EVs on the road by 2035,⁶⁷ only marking a 5-year slowdown in EV adoption from forecasts developed in 2024.⁶⁸ Consequently, while EV adoption

⁶² Executive Office of the Governor, “Executive Directive 2023-5: Conversion of State Fleet,” December 2023, available at <https://www.michigan.gov/whitmer/news/state-orders-anddirectives/2023/12/05/executive-directive-2023-5-conversion-of-state-fleet>.

⁶³ Michigan Department of Transportation, “MDOT NEVI Design-Build-Operate-Maintain (DBOM) Project - Notification of Selection,” June 2025, available at <https://www.michigan.gov/mdot/-/media/Project/Websites/MDOT/Business/Contractors/Innovative-Contracting/NEVI---2/Notification-of-Selection.pdf?rev=6451b2352ab14cd2a84a075496f62c6f&hash=12DC631641D6A886192976DBDA00C8D8>.

⁶⁴ Andreoni, M., “The Electric Vehicle Future Is Coming. Just a Little More Slowly,” *The New York Times*, September 2024, available at <https://www.nytimes.com/2024/09/05/climate/electric-vehicle-sales-projections.html>.

⁶⁵ Bloomberg, “Despite Hurdles, Vehicle Electrification in the US Is Likely Here to Stay, Finds Bloomberg Intelligence,” April 2024, available at <https://www.bloomberg.com/company/press/despite-hurdles-vehicle-electrification-in-the-us-is-likely-here-to-stay-finds-bloomberg-intelligence/>.

⁶⁶ BloombergNEF, *Electric Vehicle Outlook 2025*, 2025, available at <https://assets.bbhub.io/professional/sites/24/202506-EVO2025-Executive-Summary.pdf>.

⁶⁷ *Ibid.*

⁶⁸ BloombergNEF, “Electric Vehicle Outlook 2025 Overview,” accessed August 2025, available at <https://about.bnef.com/insights/clean-transport/electric-vehicle-outlook/#overview>.

1 forecasts in the United States have changed, EVs will continue to make up a growing
2 portion of new vehicle sales over the next decade.

3
4 American automakers recognize that to stay competitive in the race for global automotive
5 sales, they will have no choice but to continue producing and investing in EVs. In 2023,
6 global EV sales neared \$14 million, largely driven by a rapidly growing Chinese
7 automotive manufacturing industry that specializes in EV production.⁶⁹ With over 100 EV
8 brands at various price points,⁷⁰ nearly 6 million EVs were sold domestically in China in
9 2022, and in 2023 that number increased even further by 35% to 8.1 million.^{71, 72} In 2023,
10 China overcame Japan as the world's leading vehicle exporter with 5.7 million vehicles
11 exported,⁷³ 25% of which were EVs.^{74, 75} Currently, 60% of the world's EVs and over 75%
12 of the batteries that go into them are produced in China,⁷⁶ and new markets for Chinese

⁶⁹ International Energy Agency, *Global EV Outlook 2024: Trends in electric cars*, March 2025, available at <https://www.iea.org/reports/global-ev-outlook-2024/trends-in-electric-cars>.

⁷⁰ Reuters, "China's electric vehicles are around 3-5 years ahead, BYD CEO says," February 2025, available at <https://www.reuters.com/business/autos-transportation/chinas-electric-vehicles-are-around-3-5-years-ahead-byd-ceo-says-2025-02-18/>.

⁷¹ *Ibid.*

⁷² International Energy Agency, *Global EV Outlook 2024: Trends in electric cars*, March 2025, available at <https://www.iea.org/reports/global-ev-outlook-2024/trends-in-electric-cars>.

⁷³ Kennedy, S. Center for Strategic and International Studies, "The Chinese EV Dilemma: Subsidized Yet Striking," June 2024, available at <https://www.csis.org/blogs/trustee-china-hand/chinese-ev-dilemma-subsidized-yet-striking>.

⁷⁴ *Ibid.*

⁷⁵ Chang, A. and Bradsher, K., "How China Became the World's Largest Car Exporter," *The New York Times*, November 2024, available at <https://www.nytimes.com/interactive/2024/11/29/business/china-cars-sales-exports.html>.

⁷⁶ Zimmerman, M., Federal Reserve Bank of Boston, "A View of Recessions, from the Automotive Industry," *What Causes Business Cycles*, June 1998, available at https://www.bostonfed.org/-/media/Documents/conference/42/con42_20.pdf.

1 vehicles and parts are rapidly emerging, particularly in Europe and Southeast Asia.^{77, 78, 79,}
2 ^{80, 81} Although American automotive manufacturers may make slight adjustments to their
3 short-term priorities, it is clear that the longevity of these businesses is dependent upon
4 investments in EVs. As such, it is clear that, despite recent policy-driven setbacks from the
5 U.S. federal government, the shift to electrified transportation will continue and
6 Michigan's utilities will need to be prepared to meet the continued demand from EV
7 adoption growth.

8
9 **Q. How will changes to EV technology, prices, and availability impact EV adoption?**

10 A. The continued movement towards range and price parity will address the two most
11 prevalent concerns that drivers have voiced about EVs - namely range anxiety and high
12 upfront costs.⁸² Today, the median range for internal combustion engine ("ICE") passenger

⁷⁷ Kennedy, S., Center for Strategic and International Studies, "The Chinese EV Dilemma: Subsidized Yet Striking," June 2024, available at <https://www.csis.org/blogs/trustee-china-hand/chinese-ev-dilemma-subsidized-yet-striking>.

⁷⁸ Reuters, "China's electric vehicles are around 3-5 years ahead, BYD CEO says," February 2025, available at <https://www.reuters.com/business/autos-transportation/chinas-electric-vehicles-are-around-3-5-years-ahead-byd-ceosays-2025-02-18/>.

⁷⁹ Chang, A. and Bradsher, K., "How China Became the World's Largest Car Exporter," *The New York Times*, November 2024, available at <https://www.nytimes.com/interactive/2024/11/29/business/china-cars-sales-exports.html>.

⁸⁰ International Energy Agency, *Global EV Outlook 2024: Trends in electric cars*, March 2025, available at <https://www.iea.org/reports/global-ev-outlook-2024/trends-in-electric-cars>.

⁸¹ Buchholz, K., "Chinese Car Exports Continue to Soar as EV Share Grows," *Forbes*, March 2024, available at <https://www.forbes.com/sites/katharinabuchholz/2024/03/28/chinese-car-exports-continue-to-soar-as-ev-share-grows-infographic/>.

⁸² EV Charging Summit, "10 Biggest Challenges Facing the EV Industry Today," January 2023, available at <https://evchargingsummit.com/blog/challenges-facing-the-ev-industry-today/>.

1 vehicles is approximately 400 miles.⁸³ It is estimated that new EVs with a 400-mile range
2 will reach price parity with their ICE counterparts between 2029 and 2033.⁸⁴ ICE vehicles
3 and EVs with a lower range will reach price parity even sooner.⁸⁵

4
5 Since 2024, several global automakers, including General Motors, Tesla, and Volkswagen,
6 have announced that new, low-cost EV models can be expected to reach the market as early
7 as late 2025.^{86, 87, 88, 89} In June 2025, General Motors saw its monthly 2025 Chevy Equinox
8 EV registrations surge by 722%.⁹⁰ Lauded as America’s most affordable EV – starting at
9 under \$35,000 with a range of 315 miles – the success of the Equinox EV indicates that
10 EVs will continue to grow in popularity as they become more affordable and as their ranges

⁸³ U.S. Department of Energy, “FOTW #1221, January 17, 2022: Model Year 2021 All-Electric Vehicles Had a Median Driving Range about 60% That of Gasoline Powered Vehicles,” January 2022, available at <https://www.energy.gov/eere/vehicles/articles/fotw-1221-january-17-2022-model-year-2021-all-electric-vehicles-had-median>.

⁸⁴ Slowik, P. et al., International Council on Clean Transportation, *Assessment of light-duty electric vehicle costs and consumer benefits in the United States in the 2022–2035 time frame*, October 2022, available at <https://theicct.org/publication/ev-cost-benefits-2035-oct22/>.

⁸⁵ Andreoni, M., “The Electric Vehicle Future Is Coming. Just a Little More Slowly,” *The New York Times*, September 2024, available at <https://www.nytimes.com/2024/09/05/climate/electric-vehicle-sales-projections.html>.

⁸⁶ Stoklosa, A., “The Super-Affordable 2027 Chevrolet Bolt EV Is Coming Soon—Very Soon,” *Motortrend*, June 2025, available at <https://www.motortrend.com/news/2027-chevrolet-bolt-everything-you-need-to-know>.

⁸⁷ Banner, J., “The Cheap Tesla Is Almost Here—and We Finally Know What It’ll Look Like,” *Motortrend*, July 2025, available at <https://www.motortrend.com/news/cheap-tesla-model-y-coming-2025>.

⁸⁸ Jolly, J., “Can flood of cheap EVs coming to Europe save its carmakers?,” *The Guardian*, December 2024, available at <https://www.theguardian.com/business/2024/dec/31/can-flood-of-cheap-new-evs-coming-to-europe-save-european-carmakers>.

⁸⁹ While the price of these new models will likely be impacted by the implementation of tariffs on essential components, like steel, aluminum, and lithium, these impacts will apply to all vehicles, not just EVs. *See for example* Egan, M., “Every car is about to get more expensive. ‘It’s just the math,’ former Ford CEO says,” *CNN Business*, April 2025, available at <https://www.cnn.com/2025/04/03/business/car-prices-tariffs-trump#>.

⁹⁰ Johnson, P., “The Chevy Equinox EV is flying off the lot after registrations surged 722% in June,” *Electrek*, August 2025, available at <https://electrek.co/2025/08/14/chevy-equinox-ev-flying-off-the-lot-registrations-surge/>.

1 increase, in spite of political headwinds. Furthermore, in August 2025, Ford announced its
2 new Universal EV Production System,⁹¹ which will make the EV manufacturing process
3 40% faster than current methods and will use a new battery composition that is 30%
4 cheaper than industry standard lithium-ion batteries.⁹² In the same announcement, Ford
5 revealed its plans to launch a mid-size pick-up truck with a starting price of \$30,000 by
6 2027, which will be on par with current comparable ICE models.⁹³ This announcement
7 clearly indicates that, federal obstacles notwithstanding, American automotive
8 manufacturers are still committed to developing new offerings and streamlining their
9 production processes, which will make EVs more affordable for drivers across the country.

10
11 In addition to the new car market, EV affordability will also improve due to growth of the
12 used EV market, which is expected to grow in 2026 due to the number of leased EVs
13 coming to the end of their lease terms.^{94, 95} Lease-end vehicles are often sold at auctions,
14 where used vehicle dealers purchase their inventory.⁹⁶ Reports show that EV leases rose

⁹¹ Ford Motor Company, “Ford’s \$5B Bet on America: Innovation Meets Efficiency in New EV Platform, Assembly Process and Midsize Truck,” August 2025, available at <https://www.fromtheroad.ford.com/us/en/articles/2025/ford-affordable-electric-vehicle-platform-midsize-electric-truck>.

⁹² White, J., “Ford’s Answer to China: A Completely New Way of Making Cars,” *Wired*, August 2025, available at <https://www.wired.com/story/fords-answer-to-china-a-completely-new-way-of-making-cars/>.

⁹³ *Ibid.*

⁹⁴ Toussaint, K., “The first big batch of used EVs will hit the market in 2026. No one knows what’s going to happen,” *Fast Company*, January 2024, available at <https://www.fastcompany.com/91018102/the-first-big-batch-of-used-evs-will-hit-the-market-in-2026-no-one-knows-whats-going-to-happen>.

⁹⁵ St. John, A., “Don’t buy an EV — lease one instead. Here’s why.,” *Business Insider*, March 2023, available at <https://www.businessinsider.com/ev-electric-car-lease-vs-purchase-buying-tips-cost-2023-2>.

⁹⁶ Auto4Export, “Why Do Cars Go to Auction? Understanding the Reasons Behind Auto Auctions,” December 2024, available at <https://www.auto4export.com/blog/why-do-cars-go-to-auction-understanding-the-reasons-behind-auto-auctions>.

1 from 8.6% of all EV sales at the beginning of 2023 to 23.9% at the end of the year.⁹⁷ In
 2 fact, according to a report from Experian, EVs accounted for over 20% of all new leases
 3 from 2024 to 2025.⁹⁸ Consequently, as two of the most significant barriers to EV adoption
 4 come down, new drivers that make up the early majority phase of adoption⁹⁹ will start to
 5 buy into the EV market.¹⁰⁰

6
 7 **Q. What is the State of Michigan doing to enable EV adoption?**

8 A. In December 2023, Governor Whitmer issued Executive Directive 2023-5 to transition the
 9 state's fleet to zero emission vehicles ("ZEVs"), stating that the state's LD vehicles must
 10 be converted to zero-emission alternatives by 2033 and MHD vehicles must be converted
 11 to ZEVs by 2040.¹⁰¹ Executive Directive 2023-5 also directs the state to coordinate with
 12 higher education institutions and local units of government to assist these entities to

⁹⁷ Toussaint, K., "The first big batch of used EVs will hit the market in 2026. No one knows what's going to happen," *Fast Company*, January 2024, available at <https://www.fastcompany.com/91018102/the-first-big-batch-of-used-evs-will-hit-the-market-in-2026-no-one-knows-whats-going-to-happen>.

⁹⁸ Experian Automotive, "State of the Automotive Finance Market Q2 2025," August 2025, available at <https://www.experian.com/content/dam/noindex/na/us/automotive/finance-trends/experian-safm-q2-2025.pdf>.

⁹⁹ Everett Rogers' diffusion of innovations theory explains the adoption of new concepts and technologies by creating consumer classifications based on what motivates them to accept the new idea or item and when they will adopt it for themselves. The main classifications identified in order of time to adoption are "innovators," "early adopters," "early majority," "late majority," and "laggards." Innovators make up 2.5% of the adopters, early adopters - 13.5%, early majority - 34%, late majority - 34%, and laggards - 16%. It is assumed that a product or idea has moved from niche to mainstream penetration once it is in the early majority adoption phase. See Halton, C., "Diffusion of Innovations Theory: Definitions and Examples," *Investopedia*, May 2025, available at <https://www.investopedia.com/terms/d/diffusion-of-innovations-theory.asp>; and On Digital Marketing, "The 5 Customer Segments of Technology Adoption," accessed July 2025, available at <https://ondigitalmarketing.com/learn/odm/foundations/5-customer-segments-technology-adoption/>.

¹⁰⁰ Thornton, T. and Teasdale, R., Baringa, "From early adopters to early majority: Driving the next phase of EV growth," March 2025, available at <https://www.baringa.com/en/insights/low-carbon-futures/driving-next-phase-of-ev-growth/>.

¹⁰¹ Executive Office of the Governor, "Executive Directive 2023-5: Conversion of State Fleet," December 2023, available at <https://www.michigan.gov/whitmer/news/state-orders-anddirectives/2023/12/05/executive-directive-2023-5-conversion-of-state-fleet>.

1 transition to zero-emission fleets.¹⁰² As of November 2023, there were 137,073 publicly
2 owned vehicles across the state, including vehicles owned or leased by the state, counties,
3 municipalities, or other local units of government.¹⁰³ Of those vehicles, 37,415 are
4 classified as automobiles, 866 as buses, 97,987 as trucks, and 805 as motorcycles.¹⁰⁴ As of
5 December 2024, there were 14,761 owned and leased vehicles in the State of Michigan's
6 vehicle fleet alone, and nearly 95% were classified as LD while the remaining 5% were
7 MHD vehicles.¹⁰⁵ In July 2024, the State of Michigan announced a partnership between
8 Geotab Inc., a transportation solutions provider, and Wheels, a fleet management company,
9 to provide telematics solutions that would help to prioritize the vehicles appropriate for
10 electrification and identify operational efficiency opportunities.¹⁰⁶ The transition of the
11 state fleet from ICE vehicles to EVs will represent considerable EV adoption growth in
12 Michigan for which the state's utilities will need to plan for over the next decade.
13

¹⁰² *Ibid.*

¹⁰³ U.S. Department of Transportation, Federal Highway Administration, "Highway Statistics 2022," February 2025, available at <https://www.fhwa.dot.gov/policyinformation/statistics/2022/mv1.cfm>.

¹⁰⁴ *Ibid.*

¹⁰⁵ Michigan Department of Technology, Management, and Budget, *2025 State of Michigan Fleet Plan*, December 2024, available at <https://www.michigan.gov/dtmb/-/media/Project/Websites/dtmb/Law-and-Policies/Legislative-Reports/FY2025/2025-Fleet-Plan.pdf?rev=92dfd053e5514de3b3b081d2c357ce49&hash=66D77ECA9DDB57031EC46E63964CA4A1>.

¹⁰⁶ Geotab Inc., "Michigan Selects Geotab and Wheels for Zero-Emission Fleet Initiative, Aligning with Executive Directive," July 2024, available at <https://www.geotab.com/press-release/michigan-contract/>.

1 Increasing access to and awareness of public charging infrastructure has also been shown
 2 to directly enable customers to purchase EVs.^{107, 108, 109, 110} In addition to utility rebate
 3 programs, several state and federal funding programs are increasing access to charging
 4 infrastructure across Michigan. For example, in January 2025, the Michigan Department
 5 of Environment, Great Lakes, and Energy (“EGLE”) launched the Clean Fuel and Charging
 6 Infrastructure (“CFCI”) grant program to enable charging infrastructure deployment to
 7 multi-family housing, public, and fleet applications.¹¹¹ Separately, in June 2025, the
 8 Michigan Department of Transportation announced the awardees for its second round of
 9 National Electric Vehicle Infrastructure (“NEVI”) program funds.¹¹² Increased flexibility
 10 in the NEVI program announced by the U.S. Department of Transportation in August
 11 2025¹¹³ could mean a more efficient deployment of program funds and supported charging

¹⁰⁷ Osaka, S., The Washington Post, “For each public charger, here’s how many EVs are looking to plug in,” May 2024, available at <https://www.washingtonpost.com/climate-solutions/2024/05/20/charging-stations-lag-ev-sales/>.

¹⁰⁸ Center for Sustainable Energy, “The State of Electric Vehicle Adoption in the U.S. and the Role of Incentives in Market Transformation,” September 2023, available at <https://energycenter.org/thought-leadership/blog/stateelectric-vehicle-adoption-us-and-role-incentivesmarket#:~:text=Publicly%20available%20EV%20charging%20inspires,apartments%2C%20to%20charge%20an%20EV.>

¹⁰⁹ U.S. Department of Energy, Alternative Fuels Data Center, “Charging Electric Vehicles in Public,” June 2024, available at <https://afdc.energy.gov/fuels/electricity-charging-public>.

¹¹⁰ International Energy Agency, “Global EV Outlook 2024: Moving towards increased affordability,” 2024, available at <https://iea.blob.core.windows.net/assets/a9e3544b-0b12-4e15-b407-65f5c8ce1b5f/GlobalEVOutlook2024.pdf>.

¹¹¹ Department of Environment, Great Lakes, and Energy, “Clean Fuel and Charging Infrastructure Program,” July 2024, available at <https://www.michigan.gov/egle/about/organization/materials-management/energy/rfps-loans/clean-fuel-and-charging-infrastructure-program>.

¹¹² Michigan Department of Transportation, “NEVI Round 2 Selections,” June 2025, available at <https://www.michigan.gov/mdot/-/media/Project/Websites/MDOT/Business/Contractors/Innovative-Contracting/NEVI---2/Notification-of-Selection.pdf?rev=6451b2352ab14cd2a84a075496f62c6f&hash=12DC631641D6A886192976DBDA00C8D8>.

¹¹³ Schwab, G., “Trump administration pledges to keep, streamline much-maligned EV charger program,” *The Detroit News*, August 2025, available at <https://www.detroitnews.com/story/business/autos/2025/08/11/trump-administration-pledges-to-keep-streamline-ev-charger-program/85611736007/>.

1 stations. The operationalization of the state’s NEVI-supported stations, coupled with the
2 continued deployment of CFCI funding and utility rebates, will improve consumer
3 visibility of new and existing charging opportunities throughout the state, instilling greater
4 confidence that customers will be adequately supported if they purchase an EV.
5

6 **C. EV IMPACTS ON LOAD**

7 **Q. How did the residential and commercial charging categories contribute to EV load**
8 **across the Company’s territory from April 2024 to March 2025?**

9 A. The Company’s 2025 TEP annual update notes that the residential and commercial
10 charging categories accounted for approximately 55% and 45% of EV load respectively
11 between April 2024 and March 2025.¹¹⁴ Of the commercial charging load, over 30% came
12 from charging at DCFC stations.¹¹⁵ Notably, EV load from commercial charging saw a
13 50% increase between 2024 and 2025, which the Company attributes to the increased
14 utilization of public DCFC across its service territory.¹¹⁶ The Company assumes that
15 approximately 67% of LD EVs will charge at a single designated L2 charger (nearly a 1-
16 to-1 ratio) at a private residence or fleet location, while 33% will be dependent on public
17 charging.¹¹⁷ Nationally, 83% of charging occurs at home.¹¹⁸ The difference between public
18 charging in the Company’s service territory and the national average (about 17%) suggests

¹¹⁴ Consumers Energy, “Transportation Electrification Plan Annual Progress Report 2025,” Case No. U-21538, June 2025, p. 9.

¹¹⁵ *Ibid.*

¹¹⁶ *Ibid.*

¹¹⁷ *Id.*, p. 10.

¹¹⁸ International Energy Agency, “Global EV Outlook 2024: Moving towards increased affordability,” 2024, available at <https://iea.blob.core.windows.net/assets/a9e3544b-0b12-4e15-b407-65f5c8ce1b5f/GlobalEVOutlook2024.pdf>.

1 that a significant portion of the EV load in its territory is tied to EVs coming from outside
2 its service territory to reach popular tourist destinations.¹¹⁹

3
4 **Q. How will tourism impact EV load growth in the Company's electric service territory?**

5 A. As previously noted, improvements to EV range and charging access will allow EV drivers
6 to feel more comfortable taking their EVs on longer road trips. Witness Myrom notes that
7 many popular Michigan tourist destinations, and the routes to get to them, reside in the
8 Company's electric territory.¹²⁰ A report from the Michigan Economic Development
9 Corporation found that over 131 million tourists visited Michigan in 2024,¹²¹ an increase
10 of nearly 3 million visitors from the previous year.¹²² From 2021-2023, 36% of tourists
11 visiting the west coast of the state came from the Chicago area.¹²³ Notably, EV registrations
12 in Illinois rose by over 9,800 in the first quarter of 2025, which is a 50% increase, more
13 than quadruple the national growth rate of 12% over the same period.¹²⁴ EV drivers coming
14 to Michigan's most popular tourist destinations from outside the Company's electric

¹¹⁹ Myrom Direct, p. 12.

¹²⁰ *Ibid.*

¹²¹ Michigan Economic Development Corporation, *2024 Economic Impact of Visitors to Michigan*, June 2025, available at <https://medc.app.box.com/s/3yta0ya66a7rt4s76fkjii5ax6day2i0>.

¹²² Moore, L., "Michigan welcomed a record-breaking number of visitors last year. See how they spent \$29B," *MLive*, October 2024, available at <https://www.mlive.com/life/2024/10/michigan-welcomed-a-record-breaking-number-of-visitors-last-year-see-how-they-spent-29b.html>.

¹²³ Moore, L. and Levin, S., "Where are Michigan tourists coming from? See beachside rental data," *MLive*, July 2024, available at <https://www.mlive.com/news/2024/07/where-are-michigan-tourists-coming-from-see-beachside-rental-data.html>.

¹²⁴ Borrás, J., "What EV sales slump? Illinois' EV sales outpace the nation by 4:1," *Electrek*, April 2025, available at <https://electrek.co/2025/04/06/what-ev-sales-slump-illinois-ev-sales-outpace-the-nation-by-41/>.

1 territory will likely depend on DCFC to reach their destinations.¹²⁵ Consequently, increases
2 to EV load are not only going to be driven by local EV adoption, but also, by tourists
3 coming from outside the Company's service territory.

4
5 To meet this demand, a significant number of DCFC stations are expected to be energized
6 between 2026 and 2030. As previously mentioned, the Michigan Department of
7 Transportation announced its Round 1 selections for sites supported by the NEVI program
8 in June 2024¹²⁶ and Round 2 selections were announced in June 2025.¹²⁷ Of the 84 total
9 NEVI sites, two are complete, four are currently under construction (three of which are in
10 the Company's service territory), 23 are in the design phase (13 of which are in the
11 Company's service territory), and 53 have sites selected and are awaiting contracts (33 of
12 which are in the Company's service territory).¹²⁸ The two currently operational sites are
13 both in the Company's electric service territory – the first having come online in December

¹²⁵ Blink Charging, "When should you use a DC Fast Charger," April 2025, available at <https://blinkcharging.com/blog/when-should-you-use-a-dc-fast-charger>.

¹²⁶ Michigan Department of Transportation, "NEVI Round 1 selection results," June 2024, available at <https://www.michigan.gov/mdot/-/media/Project/Websites/MDOT/Business/Contractors/Innovative-Contracting/NEVI/Round-1-Notification-of-Selection.pdf?rev=179bc81b311441d490d04950775e6fe9&hash=302C7A01C202CF290C3FF8FD15AD82C8>.

¹²⁷ Michigan Department of Transportation, "NEVI Round 2 selection results," June 2025, available at <https://www.michigan.gov/mdot/-/media/Project/Websites/MDOT/Business/Contractors/Innovative-Contracting/NEVI---2/Notification-of-Selection.pdf?rev=6451b2352ab14cd2a84a075496f62c6f&hash=12DC631641D6A886192976DBDA00C8D8>.

¹²⁸ Michigan Department of Transportation, "Michigan NEVI Project Status," accessed September 2025, available at <https://experience.arcgis.com/experience/0f0eafe4cefe43a0adb8104d600d3cd3/page/Home/?views=Layers>.

1 2024 in Lansing¹²⁹ and the second in 2025 in Grand Rapids.¹³⁰ Given the time between
2 NEVI award selections and energization, it is reasonable to assume that many of these
3 NEVI-supported DCFC stations will come online between the present day and 2030.

4
5 In addition to DCFC sites supported by the NEVI program, privately supported
6 installations are also expected to contribute significantly to DCFC deployment growth
7 across the state. For example, in November 2024, EVgo, a national charging provider,
8 announced that it planned to expand its partnership with the grocery store company, Meijer,
9 by deploying 480 new public fast chargers at Meijer properties across several states,
10 including Michigan.¹³¹ EVgo expects to open 30 new stations at Meijer stores by the end
11 of 2026, and another 30 by the end of 2027.¹³² This DCFC deployment growth aligns with
12 the Company's expected DCFC service requests between 2025 and 2030. Assuming a
13 utilization ratio of 85 EVs per one 250 kW DCFC, the company projects that it could
14 receive "1,400-1,700 EV service requests of 1 MW or greater by 2030."¹³³

¹²⁹ Michigan Department of Transportation, "MDOT announces first fast charging station under NEVI program live in Lansing," December 2024, available at <https://www.michigan.gov/mdot/news-outreach/pressreleases/2024/12/11/mdot-announces-first-fast-charging-station-under-nevi-program-live-in-lansing>.

¹³⁰ Michigan Department of Transportation, "Michigan NEVI Project Status," accessed September 2025, available at <https://experience.arcgis.com/experience/0f0eafe4cefe43a0adb8104d600d3cd3/page/Home/?views=Layers>.

¹³¹ EVgo Fast Charging, "EVgo and Meijer Expand Partnership to Install up to 480 New Fast Charging Stalls at Meijer Locations Across Midwest," November 2024, available at <https://www.evgo.com/press-release/evgo-and-meijer-expand-partnership-to-install-up-to-480-new-fast-charging-stalls-at-meijer-locations-across-midwest/>.

¹³² *Ibid.*

¹³³ *Id.*, p. 10.

1 **Q. Are there additional considerations for load growth attributable to fleet MHD EV**
2 **deployment in the Company's service territory?**

3 LD EVs are reaching price parity and range parity with ICE vehicles faster than the MHD
4 EV segment.^{134, 135} As such, I expect that Michigan will continue to see more rapid growth
5 in LD EV adoption.¹³⁶ However, because demand for charging is often more concentrated
6 for fleet MHD EVs, that load may also be significant in the future.

7
8 In addition, the magnitude of EV adoption for both LD and MHD EV segments is expected
9 to be far higher in existing population centers where electricity demand is already high.¹³⁷

10 For passenger vehicle drivers, this can be partly attributed to the more robust EV charging
11 infrastructure in place within urban areas, as well as shorter driving distances to common
12 places of interest, such as workplaces, doctor's offices, and grocery stores.^{138, 139} In
13 addition, the population density, coupled with the proximity to innovative industry leaders

¹³⁴ U.S. Department of Energy Vehicle Technologies Office, "FOTW #1354, August 5, 2024: Electric Vehicle Battery Pack Costs for a Light-Duty Vehicle in 2023 Are 90% Lower than in 2008, according to DOE Estimates," August 2024, available at <https://www.energy.gov/eere/vehicles/articles/fotw-1354-august-5-2024-electric-vehicle-battery-pack-costs-light-duty>.

¹³⁵ National Renewable Energy Lab (NREL), "Study Examines Cost Competitiveness of Zero-Emission Trucks," April 2024, available at <https://www.nrel.gov/news/program/2024/study-examines-cost-competitivenessof-zero-emission-trucks.html>.

¹³⁶ Energy Power Research Institute, Inc., "GridREADY: Preparing for EV Loads at Scale through Improved Planning, Prioritization, and Proactiveness," February 2025, available at <https://epri.app.box.com/folder/311418861347>.

¹³⁷ Energy Power Research Institute, Inc., "GridREADY: Preparing for EV Loads at Scale through Improved Planning, Prioritization, and Proactiveness," February 2025, available at <https://epri.app.box.com/folder/311418861347>.

¹³⁸ Sala, L. et al., "Generating demand responsive bus routes from social network data analysis," Transportation Research Part C: Emerging Technologies, 128 (2021), pp. 1-15, available at <https://www.sciencedirect.com/science/article/abs/pii/S0968090X21002102>.

¹³⁹ Higuera-Castillo, E. et al., "Voltage variations: Unraveling electric vehicle appeal in urban vs. rural areas," Cities, Vol. 159, April 2025, available at <https://www.sciencedirect.com/science/article/pii/S0264275125001155#bb0305>.

1 and start-ups, enables faster information sharing and diffusion of new innovations.¹⁴⁰ For
2 MHD drivers, fleet depots and manufacturing sites are often collocated with local
3 communities, transportation infrastructure, and a larger labor pool, and therefore are more
4 often found near population centers.¹⁴¹ Consequently, while LD EVs will be more widely
5 dispersed across the state, their concentration, coupled with the concentration of MHD EV,
6 will result in higher EV load where electricity demand is already high, emphasizing the
7 need for strategic grid planning.

8
9 This is reflected in the Electric Power Research Institute's ("EPRI") eRoadmap GridReady
10 tool, which indicates that a majority of electric load growth attributable to EVs is going to
11 be concentrated in dense population centers and along freight corridors, such as around the
12 Detroit, Lansing, and Grand Rapids areas.¹⁴² And, of the top 10 counties projected to see
13 the largest increases in EV electricity load, three – Kent, Ottawa, and Kalamazoo – are
14 concentrated in the Company's service territory.^{143, 144} EPRI reports that this will result in

¹⁴⁰ Colville, R., "Welcome to the 'Great Acceleration': how a faster world is helping to make us all richer," *Wired*, August 2016, available at <https://www.wired.com/story/cities-lead-to-growth-speed-creativity/>.

¹⁴¹ Steele, C.W. et al., "Background Research Material for Freight Facility Selection: A Guide for Public Officials (NCFRP Report 13)," Chapter 5: The Location Selection Process, May 2011, available at <https://nap.nationalacademies.org/read/22862/chapter/9>.

¹⁴² Electric Power Research Institute (EPRI), "eRoadmap GridReady," accessed July 2025, available at <https://eroadmap.epri.com/>.

¹⁴³ Energy Power Research Institute, Inc., "GridREADY: Preparing for EV Loads at Scale through Improved Planning, Prioritization, and Proactiveness," February 2025, available at <https://epri.app.box.com/folder/311418861347>.

¹⁴⁴ Energy Power Research Institute, Inc., "eRoadMAP," accessed July 2025, available at <https://eroadmap.epri.com/>.

1 12,000 MWh in daily load growth attributable to EVs across the state, less than 2,000 MWh
2 of which will come from MHD EVs.¹⁴⁵

3
4 However, while MHD EV adoption and attributed load is relatively low today, the upgrade
5 requirements to support this scale of concentrated adoption will require time and careful
6 planning on the part of the state's utilities.¹⁴⁶ This is because, depending on the vehicle
7 type, battery size, and type of charging, a single MHD EV can require 0.4-1.0 MWh to get
8 to a full state of charge.^{147, 148} A fleet operator with between 10 and 100 MHD EVs in its
9 fleet could require anywhere from 10 to 100 MWh of energy to support its daily
10 operations,¹⁴⁹ and depending on when that charging occurs, this could require significant
11 distribution system and substation upgrades. A 2021 study from the National Renewable
12 Energy Lab found that when short-haul heavy-duty fleets actively participated in smart or
13 managed charging programs, 90% of the 36 substations were able to fully supply those
14 fleets without distribution system upgrades.¹⁵⁰ Consequently, preparing for increased
15 MHD vehicle electrification will require strategic planning and implementation of
16 managed charging programs.

¹⁴⁵ Energy Power Research Institute, Inc., "GridREADY: Preparing for EV Loads at Scale through Improved Planning, Prioritization, and Proactiveness," February 2025, available at <https://epri.app.box.com/folder/311418861347>.

¹⁴⁶ *Ibid.*

¹⁴⁷ Freightliner, "You Asked, We Answered: Electric Truck FAQs," accessed July 2025, available at <https://www.freightliner.com/blog-and-newsletters/electric-truck-faqs/>.

¹⁴⁸ Kane, M., "Tesla Launches 1,000-Volt Powertrain: Semi Is First But Not The Last," December 2022, available at <https://insideevs.com/news/624822/tesla-1000volt-powertrain-semi-first/>.

¹⁴⁹ National Renewable Energy Laboratory, "Researchers Identify Near-Term Opportunity for Heavy-Duty Electric Trucks," June 2021, available at <https://www.nrel.gov/news/detail/program/2021/researchers-identify-near-term-opportunities-for-heavy-duty-trucks>.

¹⁵⁰ *Ibid.*

D. IMPLICATIONS OF EV ADOPTION FOR THE COMPANY AND ITS CUSTOMERS

Q. What is the value of enabling EV adoption in the Company's service territory?

A. As previously stated, experts assert that the existence of public charging infrastructure directly enables customers to purchase EVs,^{151, 152, 153, 154} leading to significant at-home charging and revenue from electricity sales.^{155, 156, 157, 158, 159} In its 2025 TEP, the Company

¹⁵¹ Osaka, S., The Washington Post, “For each public charger, here’s how many EVs are looking to plug in,” May 2024, available at <https://www.washingtonpost.com/climate-solutions/2024/05/20/charging-stations-lag-ev-sales/>.

¹⁵² Center for Sustainable Energy, “The State of Electric Vehicle Adoption in the U.S. and the Role of Incentives in Market Transformation,” September 2023, available at <https://energycenter.org/thought-leadership/blog/stateelectric-vehicle-adoption-us-and-role-incentivesmarket#:~:text=Publicly%20available%20EV%20charging%20inspires,apartments%2C%20to%20charge%20an%20EV.>

¹⁵³ U.S. Department of Energy, Alternative Fuels Data Center, “Charging Electric Vehicles in Public,” June 2024, available at <https://afdc.energy.gov/fuels/electricity-charging-public>.

¹⁵⁴ International Energy Agency, “Global EV Outlook 2024: Moving towards increased affordability,” 2024, available at <https://iea.blob.core.windows.net/assets/a9e3544b-0b12-4e15-b407-65f5c8ce1b5f/GlobalEVOutlook2024.pdf>.

¹⁵⁵ Nadel, S., American Council for an Energy-Efficient Economy (ACEEE), “Charging Ahead: How EVs Could Drive Down Electricity Rates,” January 2024, available at <https://www.aceee.org/blog-post/2024/01/charging-ahead-how-evs-could-drive-down-electricity-rates>.

¹⁵⁶ Metz, L. et al., Synapse Energy Economics, Inc., “Distribution System Investments to Enable Medium- and HeavyDuty Vehicle Electrification: A Case Study of New York,” April 2023, available at <https://acrobat.adobe.com/id/urn:aaid:sc:US:3ef62d18-a652-4848-a2a5-15eb2771d8cc>.

¹⁵⁷ Synapse Energy Economics, Inc., “Are Driving Rates Down for All Customers: State-by-State Cumulative EV Net Rate Impact Summary,” June 2024, available at https://www.synapse-energy.com/sites/default/files/EV%20All%20State%20List%20PDF_0.pdf.

¹⁵⁸ Satchwell, A. et al., Prepared for the U.S. Department of Energy, “Quantifying the Financial Impacts of Electric Vehicles on Utility Ratepayers and Shareholders,” February 2023, available at https://etapublications.lbl.gov/sites/default/files/ev_financial_impacts_final_report_final_draft_02092023.pdf.

¹⁵⁹ California Public Utilities Commission, “Utility Cost and Affordability of the Grid of the Future: An Evaluation of Electric Costs, Rates, and Equity Issues Pursuant to P.U. Code Section 913.1. 2021,” available at https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/office-of-governmental-affairs-division/reports/2021/senate-bill-695-report-2021-and-en-bancwhitepaper_final_04302021.pdf.

1 indicates that TEP customer load management programming costs will amount to
2 approximately \$113 million between 2025 and 2031. While this does not include costs to
3 upgrade the distribution system to meet increased EV load, the cost of the TEP program
4 investments is drastically offset by the over \$755 million in rate relief, netting
5 approximately \$642 million for all customers in the Consumers service territory between
6 2025 and 2031.¹⁶⁰

7
8 Similar impacts have been observed in other states. For example, in a Synapse Energy
9 Economics study, from 2012 - 2019, California utilities Pacific Gas and Electric (“PG&E”) and
10 Southern California Edison (“SCE”) managed EV programs of about \$220 million and
11 \$150 million, respectively.^{161, 162} This encouraged EV adoption, leading to increased
12 revenue from charging amounting to nearly \$700 million in PG&E’s territory and \$500
13 million in SCE’s territory.^{163, 164} Synapse Energy Economics conducted a follow-up study
14 of other utilities in 2024, examining the revenues attributable to EV charging and the
15 marginal generation, transmission, and distribution costs of providing electricity to EVs

¹⁶⁰ Foley, N., CONSUMERS Electric Company, “CONSUMERS Electric Transportation Electrification Plan - Filed,” Exhibit A29, Schedule S1, April 2025, available at <https://mi-psc.my.site.com/sfc/servlet.shepherd/version/download/068cs00000lnYS8AAM>.

¹⁶¹ Alliance for Transportation Electrification and Plug In America, *The Missing Piece on Meeting Transportation Electrification Goals: Utility Education and Outreach Programs*, December 2020, available at <https://evtransportationalliance.org/wp-content/uploads/2021/11/2020-Education-Outreach-White-Paper.pdf>.

¹⁶² Frost, J. et al., Synapse Energy Economic, Inc. “Electric Vehicles Are Driving Electric Rates Down,” June 2020, available at https://www.synapse-energy.com/sites/default/files/EV_Impacts_June_2020_18-122.pdf.

¹⁶³ Alliance for Transportation Electrification and Plug In America, *The Missing Piece on Meeting Transportation Electrification Goals: Utility Education and Outreach Programs*, December 2020, available at <https://evtransportationalliance.org/wp-content/uploads/2021/11/2020-Education-Outreach-White-Paper.pdf>.

¹⁶⁴ Frost, J. et al., Synapse Energy Economic, Inc. “Electric Vehicles Are Driving Electric Rates Down,” June 2020, available at https://www.synapse-energy.com/sites/default/files/EV_Impacts_June_2020_18-122.pdf.

1 between 2011 and 2021. It found that EV drivers have contributed about \$18 million more
 2 than their associated system costs in each of Illinois¹⁶⁵ and Virginia,¹⁶⁶ \$26.7 million more
 3 in Colorado,¹⁶⁷ and \$85.3 million more in New Jersey.¹⁶⁸ Consequently, as utilities
 4 continue to invest in EV programs, the resultant increased EV adoption actually leads to
 5 downward rate pressure for all ratepayers.¹⁶⁹

6
 7 In addition, EV deployment represents an opportunity to maximize the benefits of EVs in
 8 service to the local distribution system. For the grid-operator, the deployment and use of
 9 bidirectional-capable EVs and EV chargers creates an available resource to balance grid
 10 conditions and allows utilities to defer investment in other more intensive grid-scale
 11 operations.¹⁷⁰ According to a study by EPRI, California's current frequency regulation
 12 market could be fully served by only around 100,000 vehicle-to-grid ("V2G")-enabled

¹⁶⁵ Shenstone-Harris, S. et al., Synapse Energy Economics, Inc., "Electric Vehicles are Driving Rates Down for All Customers, State Factsheet: Illinois," April 2024, available at <https://www.synapse-energy.com/sites/default/files/Electric%20Vehicles%20Are%20Driving%20Rates%20Down%20for%20All%20Customer%20Illinois%20May%202024.pdf>.

¹⁶⁶ Shenstone-Harris, S. et al., Synapse Energy Economics, Inc., "Electric Vehicles are Driving Rates Down for All Customers, State Factsheet: Virginia," April 2024, available at <https://www.synapse-energy.com/sites/default/files/Electric%20Vehicles%20Are%20Driving%20Rates%20Down%20for%20All%20Customer%20Virginia%20May%202024%2024-023.pdf>.

¹⁶⁷ Shenstone-Harris, S. et al., Synapse Energy Economics, Inc., "Electric Vehicles are Driving Rates Down for All Customers, State Factsheet: Colorado," April 2024, available at <https://www.synapseenergy.com/sites/default/files/Electric%20Vehicles%20Are%20Driving%20Rates%20Down%20for%20All%20Customer%20Colorado%20May%202024.pdf>.

¹⁶⁸ Shenstone-Harris, S. et al., Synapse Energy Economics, Inc., "Electric Vehicles are Driving Rates Down for All Customers, State Factsheet: New Jersey," April 2024, available at <https://www.synapseenergy.com/sites/default/files/Electric%20Vehicles%20Are%20Driving%20Rates%20Down%20for%20All%20Customer%20New%20Jersey%20April%202024.pdf>.

¹⁶⁹ Frost, J. et al., Synapse Energy Economic, Inc. "Electric Vehicles Are Driving Electric Rates Down," June 2020, available at https://www.synapse-energy.com/sites/default/files/EV_Impacts_June_2020_18-122.pdf.

¹⁷⁰ Michigan Energy Innovation Business Council and Clean Fuels Michigan, *Transportation Electrification in Michigan: A Roadmap to State Policy Actions*, October 2024, available at <https://www.mieibc.org/wp-content/uploads/2024/10/Transportation-Electrification-in-Michigan.pdf>.

1 EVs, which is a fraction of the state's goal of 5 million EVs by 2030.¹⁷¹ The same study
2 found an annual relative savings of between \$407 and \$1,018 per customer for ratepayers
3 with V2G-enabled EVs.¹⁷² Customers in California's San Diego County school district saw
4 these benefits during a 10-day 2022 heat wave, during which the school district was able
5 to send energy back to the grid and power 452 homes every day.^{173, 174} Given the grid
6 reliability challenges faced in Michigan that are identified in the Commission's audit of
7 DTE Electric and Consumers Energy,^{175, 176, 177, 178, 179} EVs represent a largely untapped
8 grid resource that would benefit ratepayers and energy providers alike.
9

¹⁷¹ Chhaya, S. Electric Power Research Institute, "Open Standards-Based Vehicle-to-Grid: Value Assessment," June 2019, available at <https://www.epri.com/research/products/000000003002014771>.

¹⁷² *Ibid.*

¹⁷³ CalMatters, "Here's how California's electric cars can feed the grid and help avoid outages," September 2023, available at <https://calmatters.org/environment/2023/07/california-electric-cars-bidirectional-charging/>.

¹⁷⁴ Sheja, C., Center for Sustainable Energy, "Grid Integration of EV Batteries Can Benefit Drivers and Energy Providers," February 2024, available at <https://energycenter.org/thought-leadership/blog/grid-integration-ev-batteries-can-benefit-drivers-and-energy-providers>.

¹⁷⁵ Michigan Public Service Commission, "MPSC releases utility audit results of state's two largest electric utilities, data that will help improve reliability in Michigan," September 2024, available at <https://www.michigan.gov/mpsc/commission/news-releases/2024/09/23/mpsc-releases-utility-audit-results-of-states-two-largest-electric-utilities>.

¹⁷⁶ Citizens Utility Board, "The Grid Audit of CONSUMERS and Consumers Energy: Some Early Takeaways," October 2024, available at <https://cubofmichigan.org/blog/the-grid-audit-of-Consumers-and-Consumers-energy-some-early-takeaways/>.

¹⁷⁷ Walton, R., "Michigan regulators order reliability improvements for Consumers Energy, CONSUMERS," *Utility Dive*, June 2025, available at <https://www.utilitydive.com/news/michigan-regulators-order-reliability-improvements-Consumers-Consumers/750769/>.

¹⁷⁸ White, E., "Northern Michigan — no stranger to wild weather — tries to cope with days of no power," *AP News*, April 2025, available at <https://apnews.com/article/michigan-ice-storm-power-outages-4807b995fd4f9acbe1cdc7715e2bbaef>.

¹⁷⁹ Rappleye, L., "Up North residents hit by ice storm endure cold, power outages: 'How are we gonna manage?'," *Detroit Free Press*, April 2025, available at <https://www.freep.com/story/news/local/michigan/2025/04/14/northern-michigan-ice-storm-power-outage-up-north/83070910007/>.

1 **Q. Why is proactive planning important for utilities when it comes to preparing for**
 2 **increased EV load growth?**

3 A. Proactive planning for EV adoption can save utilities and ratepayers in the long run.^{180, 181}

4 A 2024 study found that proactive grid maintenance and upgrades in response to increased
 5 EV load growth resulted in about \$20 million in savings compared to reactive upgrades in
 6 Con Edison's territory (New York City and Westchester County, NY), and \$10-13 million
 7 in savings in CenterPoint's service territory (Houston, TX).¹⁸² Additionally, models from
 8 the same study showed that even in the lowest EV adoption scenario, an "all proactive"
 9 upgrade approach still yielded higher savings than a mixed proactive and reactive
 10 approach.¹⁸³ This suggests that overestimating, and subsequently upgrading to meet EV
 11 load growth carries limited risk.¹⁸⁴

12
 13 Utility TEPs and distribution system plans are critical, informative tools to ensure that the
 14 Company is effectively able to predict, plan, and execute necessary distribution system

¹⁸⁰ Black & Veatch, "Pro-Active Grid Investment Assessment: Medium- and Heavy-Duty Vehicle Transportation Electrification," November 2024, available at https://library.edf.org/AssetLink/1sf1n64na1m7b636rs127w4wqvs11d4e.pdf?_gl=1*14rezcp*_gcl_au*MjczNzI5MDQ0LjE3NTM3MTg4MDQ.*_ga*NzAxMjcwMzgzLjE3NTM3MTg4MDQ.*_ga_2B3856Y9QW*cze3NTM3MTg4MDMkbzEkZzEkdDE3NTM3MTg5OTUkajQ4JGwwJGgw.

¹⁸¹ Sahoo, A. et al., BCG, "The Costs of Revving Up the Grid for Electric Vehicles," December 2019, available at https://web-assets.bcg.com/img-src/costs-revving-up-the-grid-for-electric-vehicles_tcm9-236324-64_tcm9-237341.pdf.

¹⁸² Black & Veatch, "Pro-Active Grid Investment Assessment: Medium- and Heavy-Duty Vehicle Transportation Electrification," November 2024, available at https://library.edf.org/AssetLink/1sf1n64na1m7b636rs127w4wqvs11d4e.pdf?_gl=1*14rezcp*_gcl_au*MjczNzI5MDQ0LjE3NTM3MTg4MDQ.*_ga*NzAxMjcwMzgzLjE3NTM3MTg4MDQ.*_ga_2B3856Y9QW*cze3NTM3MTg4MDMkbzEkZzEkdDE3NTM3MTg5OTUkajQ4JGwwJGgw.

¹⁸³ *Ibid.*

¹⁸⁴ *Ibid.*

1 upgrades to meet future load growth attributable to EVs.^{185, 186, 187} More specifically,
2 customer engagement driven by education and outreach programs, as well as customer
3 enrollment in rebate and TOU rates, can inform utilities of EV penetration trends in their
4 service territories and where load growth is expected. Delaying upgrades or artificially
5 reducing projected load growth risks impairing utilities' visibility into future EV-related
6 load growth, potentially resulting in suboptimal upgrade decisions, longer energization
7 timelines for new load, and grid constraints. In other words, while postponing upgrades
8 required to meet EV adoption growth may yield short-term savings, the long-term financial
9 and operational liabilities, as well as customer service impacts, could be far greater.

10
11 **E. GRID UPGRADES TO MEET DCFC LOAD**

12 **Q. What does witness Myrom say about TOU rates and their effectiveness in managing**
13 **future load?**

14 A. Witness Myrom highlights the success that the Company has had in optimizing its EV load
15 growth through TEP engagement, achieving nearly 95% off-peak charging among
16 customers enrolled in its residential TOU program.¹⁸⁸ However, witness Myrom notes that

17 in late 2023 the Company's AMI data analysis showed just 493 of the
18 30,380 EVs enrolled in Rate 1050 (Nighttime Savers) without TEP
19 rebate or incentive engagement, which equates to a mere 1.6% of EV

¹⁸⁵ Morash, S., Lawrence Berkeley National Laboratory, "Charging Ahead: Grid Planning for Vehicle Electrification," January 2024, available at <https://www.esig.energy/wp-content/uploads/2024/01/ESIG-Grid-Planning-Vehicle-Electrification-report-2024.pdf>.

¹⁸⁶ Shapiro, B. and Pesta, N., RMI, "Six Building Blocks to Prepare the Grid for EVs," October 2024, available at <https://rmi.org/six-building-blocks-to-prepare-the-grid-for-evs/>.

¹⁸⁷ Taylor, P., American Public Power Association, "Proactive Grid Build for Transportation Electrification," January 2025, available at <https://www.publicpower.org/resource/proactive-grid-build-transportation-electrification>.

¹⁸⁸ Myrom Direct, p. 5.

1 customers. Again, in late 2024, advanced metering infrastructure
2 (“AMI”) data analysis indicated just 526 of 39,950 EVs enrolled in Rate
3 1050 without TEP program engagement, which is 1.3% of EV
4 customers.¹⁸⁹
5

6 This indicates a strong positive correlation between customers participating in the TEP
7 rebate programs and shifting their charging behavior to align with utility TOU rates. As
8 such, TEP rebate programs are critical to ensuring EV customers are charging during off-
9 peak hours. However, given the low enrollment in Rate 1050, it is also clear that, under the
10 current education and outreach efforts, relying on TOU rates alone to optimize grid load is
11 not an effective long-term strategy to manage EV load, especially as adoption continues to
12 increase.¹⁹⁰
13

14 **Q. What impact will DCFC deployment have on EV load growth?**

15 A. While continued development and promotion of the TEP L2 and L1 programs will help to
16 optimize grid load for residential program participants, as previously noted, the Company
17 anticipates a significant number of DCFC installations for public and fleet applications to
18 be deployed in its electric service territory in the next five years. According to witness
19 Myrom, assuming a utilization ratio of 85 EVs per one 250 kW DCFC, the company
20 projects that it could receive “1,400-1,700 EV service requests of 1 MW or greater by
21 2030.”¹⁹¹ Company witness Jennifer Partlan also discusses the impact of new business
22 load, including from DCFC deployment, on the low-voltage distribution system, which she

¹⁸⁹ *Id.*, p. 10.

¹⁹⁰ *Ibid.*

¹⁹¹ *Id.*, p. 10.

1 indicates will require significant proactive planning to ensure demand can be met without
2 sacrificing system reliability.

3
4 **Q. Are there innovative ways for the Company to meet EV load growth while deferring**
5 **distribution system upgrade costs?**

6 A. Yes, as noted by witness Partlan, upgrading the distribution system to meet new business
7 load, such as from DCFC installations, will be costly. To avoid or defer some of these costs
8 while still meeting EV load growth, the Company could look, for example, to enable
9 flexible energization. Broadly, flexible energization refers to the ability of a large-load
10 consumer to adapt its energy consumption in response to shifts in energy supply, demand,
11 or pricing.¹⁹² In a flexible energization agreement, customers connecting a large load agree
12 to energy consumption terms with the utility that would limit energy use based either on
13 currently available grid capacity or on predetermined times to mitigate grid strain.¹⁹³
14 Customers could also agree to stagger load energization and unlock full service for the
15 required load over time.¹⁹⁴ If, for example, a fleet operator requires 10 MW of additional
16 daily load but the current grid capacity will only support 1 MW of new load, the customer
17 and the utility could agree to a timeline whereby 1 MW of the customer's demand could
18 be fulfilled immediately and the rest would be made available over time as the utility makes
19 necessary upgrades. Flexible energization methods

¹⁹² GridX, "Energy Flexibility," September 2025, available at <https://www.gridx.ai/knowledge/what-is-energy-flexibility>.

¹⁹³ United States Department of Energy, "Flexible DER & EV Connections," July 2024, available at <https://www.energy.gov/sites/default/files/2024-08/Flexible%20DER%20%20EV%20Connections%20July%202024.pdf>.

¹⁹⁴ *Ibid.*

1 improve distribution system utilization allowing more distributed energy
 2 resource (“DER”) interconnections and service connections for EV
 3 charging while lowering the cost of integration...The potential benefits of
 4 flexible connections include ...facilitat[ing] higher DER and EV adoption,
 5 lowering connection costs, and/or deferring infrastructure upgrades.
 6 Flexible [energization] methods can be applied in various scenarios, serving
 7 as a temporary or a more permanent solution. In a temporary context,
 8 flexible [energization methods] enable distributed generation, battery
 9 projects, and large EV charging centers (e.g., fleet charging and public
 10 charging locations) to connect more quickly, bridging the gap until
 11 scheduled distribution reinforcements are completed. Alternatively, it can
 12 be a longer-term solution until other proposed DER/EV charging loads
 13 create the need for an upgrade.¹⁹⁵
 14

15 According to the U.S. Department of Energy, detailed hosting capacity analyses and
 16 dynamic operating assessments are critical to standing up successful flexible energization
 17 programs.^{196, 197} Examples of existing flexible energization programs include:

- 18 • *California Pacific Gas & Electric (“PG&E”) Flex Connect* – Customers wishing to
 19 connect large loads to the distribution system agree to limit energy usage during peak
 20 periods to be connected to the grid more quickly.¹⁹⁸
- 21 • *Southern California Edison (“SCE”) Load Control Management System (“LCMS”)*
 22 *Pilot* – The LCMS pilot program allows customers to use energy based on currently

¹⁹⁵ *Ibid.*

¹⁹⁶ *Ibid.*

¹⁹⁷ Hosting capacity analyses typically offer a general overview of peak load scenarios and assume a steady state when considering DER integration. Dynamic operating assessments establish load capacity limits based on specific times to determine how much energy is available to import (or export) based on forecasts and real-time grid conditions. See United States Department of Energy, “Flexible DER & EV Connections,” July 2024, available at <https://www.energy.gov/sites/default/files/2024-08/Flexible%20DER%20%20EV%20Connections%20July%202024.pdf>.

¹⁹⁸ Lohse, J., Ampcontrol, “Flex Connect: PG&E’s Game-Changer for EV Charging and Grid Connections,” December 2024, available at <https://www.ampcontrol.io/post/pg-es-flex-connect-program-a-game-changer-for-ev-charging-and-grid-connections>.

1 available grid capacity.¹⁹⁹ The LCMS can automatically reduce or stop power to EV
2 chargers, or other devices, to avoid overloading the local grid.²⁰⁰

3 By implementing a flexible energization pilot program similar to PG&E's Flex Connect or
4 SCE's LCMS, the Company could energize new load to support DCFC installation or fleet
5 depot charging without overloading the distribution system and spread out costs to upgrade
6 the local grid over time.

8 **F. TEP PROGRAM ENHANCEMENTS**

9 **Q. Please describe the Company's existing public DCFC rebate.**

10 A. The Company's DCFC rebate is a continuation of the Company's customer projects from
11 the PowerMIDrive pilot phase of the EV initiatives. In its 2024 TEP, the Company reported
12 that 61 of the 137 DCFC sites supported by PowerMIDrive were operational.²⁰¹ Between
13 2024 and 2025, an additional 27 sites were energized in the Company's service territory.²⁰²
14 In Case No. U-21585, the Commission approved the Company's request to set its public
15 DCFC rebate to \$50,000 per port,²⁰³ a decrease from the previously approved rebates of

¹⁹⁹ United States Department of Energy, "Flexible DER & EV Connections," July 2024, available at <https://www.energy.gov/sites/default/files/2024-08/Flexible%20DER%20%20EV%20Connections%20July%202024.pdf>.

²⁰⁰ *Ibid.*

²⁰¹ Consumers Energy, "Transportation Electrification Plan 2024," Case No. U-21538, June 2024, available at <https://mi-psc.my.site.com/sfc/servlet.shepherd/version/download/0688y00000EFQgtAAH>.

²⁰² Consumers Energy, "Transportation Electrification Plan Annual Progress Report 2025," Case No. U-21538, June 2025, p. 24.

²⁰³ Michigan Public Service Commission, Case No. U-21585 Order, March 2025, p. 204.

1 \$70,000.²⁰⁴ In the current case, witness Myrom notes that “the median and average costs
 2 of a 150 kW DCFC construction project range between approximately \$200,000 and
 3 \$237,000.”²⁰⁵ In its 2024 TEP annual update, the Company indicates that make-ready costs
 4 range from \$30,608 to \$45,509 (about 13-23% of total project costs) while construction
 5 costs²⁰⁶ typically range from \$191,239 to \$199,262.²⁰⁷ Additionally, site hosts can get
 6 support from other incentives, such as the federal 30C Vehicle Refueling Property Tax
 7 Credit (“30C tax credit”),²⁰⁸ which can reduce project costs by 30%, bringing project costs
 8 down to \$140,000-\$166,000.²⁰⁹ If a site host claims the 30C tax credit, the Company’s
 9 \$50,000 DCFC rebate would cover about one-third of the total project costs, or the entirety
 10 of the make-ready costs, for a two-port DCFC installation.²¹⁰ With the repeal of the
 11 Inflation Reduction Act, however, the 30C tax credit will sunset on June 30, 2026.^{211, 212,}

²⁰⁴ *Id.*, p. 196.

²⁰⁵ Myrom Direct, p. 13.

²⁰⁶ In its 2024 TEP annual update, the Company indicates that construction costs include installation, network and maintenance plan fees, and charging station equipment. See Consumers Energy, “Transportation Electrification Plan 2024,” Case No. U-21538, June 2024, available at <https://mi-psc.my.site.com/sfc/servlet.shepherd/version/download/0688y00000EFQgtAAH>.

²⁰⁷ *Ibid.*

²⁰⁸ United States Department of Energy, “Alternative Fuels Data Center: Alternative Fuel Infrastructure Tax Credit,” Accessed September 2025, available at <https://afdc.energy.gov/laws/10513>.

²⁰⁹ Myrom Direct, p. 13.

²¹⁰ *Ibid.*

²¹¹ Evergreen Action, “Republican Megabill Is a Disaster for Energy Costs, Jobs, and Clean Energy,” June 2025, available at <https://www.evergreenaction.com/blog/senate-gops-updated-megabill-is-still-a-disaster-for-affordability-jobs-and-clean-energy>.

²¹² *The Business Times*, “Tesla braces for rough quarters ahead as US ends EV incentives,” July 2025, available at <https://www.businesstimes.com.sg/companies-markets/transport-logistics/tesla-braces-rough-quarters-ahead-us-ends-ev-incentives>.

1 ²¹³ Consequently, prospective site hosts now have less than a year to plan a site and apply
2 for the 30C tax credit.

3
4 Without the 30C tax credit, while the proposed rebate of \$50,000 per 150 kW port will
5 likely still cover a majority of the make-ready costs, the applicant will need to pay
6 approximately \$75,000 to \$93,500 per port in construction costs. Even with the Company's
7 \$50,000 rebate, this cost increase could make it more difficult to establish a workable
8 business case for DCFC investments, especially in rural and seasonal travel communities
9 where charging is most needed.

10
11 In a discovery response (Exhibit MEIU-1.3), witness Myrom indicates that “the goal of the
12 temporary DCFC rebate program is to spur the growth of quality fast charging
13 infrastructure and to do so as quickly as possible.” Reaching rural and seasonal travel
14 communities, however, remains a challenge. In its TEP 2025 annual update, the Company
15 indicates that “rural and seasonal travel communities still need incentive support to ensure
16 the skeleton network of fast chargers is sufficient to support rapidly growing EV
17 adoption.”²¹⁴

²¹³ United State Internal Revenue Service, “FAQs for modification of sections 25C, 25D, 25E, 30C, 30D, 45L, 45W, AND 179D under Public Law 119-21, 139 Stat. 72 (July 4, 2025), commonly known as the One, Big, Beautiful Bill Act (OB BB),” August 2025, Accessed September 2025, available at <https://www.irs.gov/newsroom/faqs-for-modification-of-sections-25c-25d-25e-30c-30d-45l-45w-and-179d-under-public-law-119-21-139-stat-72-july-4-2025-commonly-known-as-the-one-big-beautiful-bill-act-obbb>.

²¹⁴ Consumers Energy, “Transportation Electrification Plan Annual Progress Report 2025,” Case No. U-21538, June 2025, p. 24.

1 **Q. What are the Company’s proposed “enhancements” to its TEP programs?**

2 A. In the instant case, the Company proposes its L2 and L1 rebates be approved to apply to
3 NEMA 14-50 and NEMA 5-20 outlets, respectively.²¹⁵ The Company proposes the
4 following related to its DCFC rebate:²¹⁶

- 5 • *Rebate amount* – The Company proposes a DCFC rebate of up to \$50,000 per 150 kW
6 port, with a limit of up to four ports;
- 7 • *Geographical limitation* – The Company suggests that the DCFC rebate only be
8 available to communities that have no more than four 150 kW DCFC ports in two or
9 more locations;
- 10 • *Time limitation* – Assuming the Commission approves the Company’s proposal in the
11 order for the current case, Consumers recommends that the DCFC rebate only be
12 available for two years after approval; and
- 13 • *Selection criteria* – The Company proposes several criteria by which it could evaluate
14 DCFC rebate applications on a rolling basis. The Company notes that sites meeting
15 these criteria would be given preference over those that do not. These criteria
16 include:²¹⁷
 - 17 ○ *Access to charging and amenities* (e.g. restrooms and food options) – Applications
18 for sites with 24/7 access to charging and amenities would be given preference over
19 those that do not;

²¹⁵ Myrom Direct, pp. 12-13.

²¹⁶ *Id.*, pp.13-15.

²¹⁷ *Id.*, pp. 14-15.

- 1 ○ *Visibility* – Applications for sites that are clearly visible from the road and that have
- 2 signage to direct drivers would be given preference over those that do not;
- 3 ○ *Payment options* – Applications for DCFC that accept credit card or phone tap
- 4 options, as opposed to being limited by requiring use of a specific phone
- 5 application, would be given preference over those that do not;
- 6 ○ *Open design concept* – Applications for sites that can serve multiple vehicle types
- 7 and sizes would be given preference over those that do not; and
- 8 ○ *Overhead coverage* – Applications for sites with a canopy would be given
- 9 preference over those that do not.²¹⁸

10 The Company also proposes two requirements for DCFC rebate applicants.²¹⁹

- 11 ○ *Safety* – DCFC sites must include security lighting for an application to be
- 12 considered; and
- 13 ○ *Number of ports* – Applications for DCFC sites must include at least two 150 kW
- 14 DCFC ports. Sites offering more than two ports would also be given preference,
- 15 with a maximum of four rebates available per site host.

²¹⁸ In his outline of proposed TEP enhancements in direct testimony, witness Myrom discusses canopy coverage in conjunction with security lighting, stating that “the host site must have adequate security lighting and preferably a canopy.” See Myrom Direct, pp. 14-15. In a discovery response (Exhibit MEIU-1.3), witness Myrom clarifies that while discussed with a proposed requirement, a canopy is not required.

²¹⁹ *Ibid.*

1 **Q. What reasons does the Company provide for the proposed modifications to its L2 and**
2 **L1 rebate programs?**

3 A. The Company indicates that allowing L2 and L1 rebates to apply to NEMA 14-50 and 5-
4 20 outlet installation costs will allow more flexibility to address customers' specific
5 needs.²²⁰ Witness Myrom notes that because

6 many new EVs come with, and existing EV drivers utilize, a portable
7 charger, focusing a project on the outlet can simplify installations and
8 reduce costs for host sites... Presently only community charging host sites
9 can utilize outlets as a [Bring Your Own Charger] option, and the Company
10 believes that it is a useful option across the board to reduce infrastructure
11 costs.²²¹
12

13 The Company also suggests that this option would be particularly attractive for MFH
14 properties due to the higher infrastructure costs required to make them EV-ready.²²²
15

16 **Q. Do you agree with the Company's proposed modifications to its L2 and L1 rebate**
17 **programs?**

18 A. Not entirely. While this recommendation would allow flexibility in the program to suit the
19 customer's specific needs and reduce the customer's make-ready costs, it is unclear how
20 the Company plans to ensure that a customer with a NEMA 14-50 or 5-20 outlet will
21 actually purchase the charger and participate in the TOU rate or any future managed
22 charging program. As detailed in MEIU witness Dr. Laura Sherman's testimony in Case
23 No. U-21297 (DTE Electric Company's 2023 general electric rate case),

²²⁰ *Id.*, pp. 12-13.

²²¹ *Ibid.*

²²² *Ibid.*

1 if a customer chooses to install a NEMA 14-50 outlet (instead of directly
2 installing an EV charger), there should be a procedural assurance that the
3 customer actually acquires an EV charger to participate in the program (e.g.,
4 by the provision of a receipt or invoice to the Company). Without
5 verification, a customer could be participating in the program and receive a
6 NEMA 14-50 outlet installation but not utilize the outlet for EV charging.²²³
7
8

9 As such, the Commission should require the Company to ensure that if a customer chooses
10 to install a NEMA 14-50 outlet, that they also purchase or obtain an EV charger or charging
11 cord and provide proof of EV purchase or lease.
12

13 **Q. What reasons does the Company provide for the proposed modifications to its DCFC**
14 **rebate program?**

15 A. The Company suggests that modifying the DCFC rebate program, as discussed above, will
16 ensure that awarded rebates maximize the benefits of the DCFC installation to EV drivers,
17 site hosts, and the local community (Exhibit MEIU-1.3). Witness Myrom points to the
18 availability of other incentives, such as the 30C Vehicle Refueling Property Tax Credit,²²⁴
19 that site hosts would be able to apply for to further reduce costs to justify the proposed
20 modification to the DCFC rebate amount.²²⁵ However, as previously stated, the 30C tax
21 credit will sunset on June 30, 2026. Consequently, this should not be factored into
22 consideration when evaluating the impact of the DCFC rebate on DCFC installation costs
23 for public site hosts.

²²³ Direct Testimony of Dr. Laura Sherman on behalf of the Michigan Energy Innovation Business Council, Institute for Energy Innovation, and Advanced Energy United, Case No. U-21297, p. 16.

²²⁴ United States Department of Energy, “Alternative Fuels Data Center: Alternative Fuel Infrastructure Tax Credit,” Accessed September 2025, available at <https://afdc.energy.gov/laws/10513>.

²²⁵ Myrom Direct, p. 13.

1
2 In addition, the Company suggests that limiting the geographical eligibility will drive
3 rebate applications in communities that do not yet have DCFC infrastructure, as opposed
4 to supporting build-out in areas that already have infrastructure in place.²²⁶ Finally, the
5 Company indicates, given the competitive nature of applications for EV charging funding
6 in the limited TEP budget, the proposed criteria to evaluate applications will ensure that
7 the best sites and projects are selected to receive rebates.²²⁷
8

9 **Q. Does the Company explain how it proposes to evaluate DCFC rebate applications?**

10 A. In a discovery response (Exhibit MEIU-1.3), witness Myrom indicates that the Company
11 would review applications and award rebates on a monthly basis and that the Company
12 would make a “yes/no” determination for each criterion to determine whether to award
13 funding to an applicant. An applicant would have to meet the minimum criteria (i.e., the
14 site must have security lighting and at least two 150 kW DCFC ports) to be eligible for any
15 program funding (Exhibit MEIU-1.3). The Company did not explain how it would
16 determine the rebate amount an applicant would be eligible to receive based on whether
17 the site design meets the other optional criteria.
18

²²⁶ *Ibid.*

²²⁷ *Id.*, pp. 14-15.

1 **Q. Do you agree with the Company’s proposed modifications to its DCFC rebate**
2 **program?**

3 A. Not entirely. I agree with the Company that safety and access to amenities has become a
4 top area of focus for EV charging manufacturers, site hosts, and installers.²²⁸ The
5 Company’s proposed required criteria (i.e., security lighting and minimum number of
6 ports) are reasonable, and the Commission should approve these modifications to the
7 DCFC rebate program. However, while I appreciate that the limited TEP budget requires
8 more careful evaluation of rebate application, I have concerns with some of the Company’s
9 proposed optional criteria for its DCFC rebate program as described below.

- 10 • *Rebate amount* – As previously stated, the Company notes that “the median and
11 average costs of a 150 kW DCFC construction project range between approximately
12 \$200,000 and \$237,000.”²²⁹ Under current conditions where the applicant can access
13 the 30C tax credit, the Company’s \$50,000 DCFC rebate would cover about one-third
14 of the total project costs, or the entirety of the make-ready costs, for a two-port DCFC
15 installation.²³⁰ However, as previously noted, based on the Company’s cost
16 assumptions, the make-ready cost per DCFC port will increase to between \$75,000 and
17 \$93,500 without the tax credit. This cost increase could make it more difficult to
18 establish a workable business case for DCFC investments, especially in rural and
19 seasonal travel communities where charging is most needed. If the goal is to deploy
20 funds efficiently and prioritize communities currently lacking DCFC, it may be

²²⁸ United States Joint Office of Energy and Transportation, “Physical Safety and Security at Electric Vehicle Charging Sites,” June 2024, available at <https://driveelectric.gov/files/physical-site-security.pdf>.

²²⁹ Myrom Direct, p. 13.

²³⁰ *Ibid.*

1 necessary to increase the rebate amount. To prepare for the loss of the 30C tax credit
2 at the end of 2026 and to ensure that the DCFC program is as effective and impactful
3 as possible, the Commission should direct the Company to increase the DCFC rebate
4 amount to up to \$70,000 per port.²³¹

- 5 • *Time limitation* – Given the new 30C tax credit sunset of June 30, 2026 and the amount
6 of time needed to plan DCFC sites, the proposed two-year limit on the Company’s
7 DCFC rebate program is simply too short. At the very least, assuming the rebate
8 amount remains the same, the program should be allowed to extend until depletion of
9 program funding or for six years, whichever comes first. Artificially truncating a
10 program when previously allocated funding remains unspent is not reasonable.
11 Therefore, the Commission should reject the Company’s proposed DCFC program
12 two-year time limitation.

- 13 • *Geographical limitation* – The rationale to prioritize DCFC rebates to communities that
14 do not yet have adequate DCFC infrastructure (i.e., no more than four 150 kW DCFC
15 ports per community) is sound. In a discovery response (Exhibit MEIU-1.4), witness
16 Myrom defines a community as a “traditional governmental boundary.” This could
17 mean any number of official boundaries (e.g. village, municipal, school district, county,
18 political district, zip code etc.) and is too vague. Rebate applicants need a clear
19 description of what the Company means by “community” or “traditional government
20 boundary” in order to determine whether a site could be considered eligible for the

²³¹ The Company estimates that the cost of a two-port DCFC installation is roughly between \$140,000 and \$166,000, after factoring in the 30C tax credit. As such, the cost per port with the 30C tax credit is \$70,000-83,000. Without the tax credit, however, the cost of a two-port DCFC installation remains the same as the Company’s pre-tax credit estimate of \$200,000-\$237,000. As such the cost per port increases to between \$75,000 and \$93,500, a difference of between \$5,000 and 10,500. Assuming the maximum cost per port, increasing the Company’s public DCFC rebate by \$20,000 would then roughly cover the cost increase of two port.

1 rebate program. As such, the Commission should require the Company to clearly define
2 “community” in its DCFC rebate program application guidelines.

3
4 **Q. Do you have any other concerns with the Company’s proposed modifications to its**
5 **DCFC rebate program?**

6 **A.** Yes. Conceptually, I support the Company’s efforts to ensure that its rebates are used to
7 support DCFC installations that meet – or exceed – the customer’s needs. However, the
8 optional criteria, and the manner in which the Company proposes to evaluate and compare
9 applications, lack clarity.

10
11 As stated above, it is imperative that site hosts have a clear understanding of the rebate
12 amount they are eligible to receive to effectively plan for the associated project costs. To
13 address this concern, the Company could establish designated amounts or weighted
14 amounts associated with each project criterion and develop a publicly available rubric by
15 which it would score DCFC project applications. If this were done, an applicant proposing
16 a project that meets all the optional criteria would be eligible to receive the maximum
17 rebate amount. Subsequently, applicants proposing to meet some, but not all of the optional
18 criteria, would be eligible for a lesser—but knowable and known—rebate amount. This
19 could be based on evenly distributed weights or dollar amounts, or the Company could
20 designate certain criteria as more important and therefore worthy of greater weight or a
21 higher dollar amount.

22

1 In a discovery response (Exhibit MEIU-1.3), witness Myrom indicates that the Company
2 intends to review and award DCFC rebate applications on a monthly basis. This leaves the
3 evaluation process vulnerable to subjectivity in the review process from one month to the
4 next, which could make the review process more contentious as the Company continues to
5 issue rebates and spend program funds. Creating a rubric, as described above, would make
6 it easier for the Company to objectively review each application, ensuring that the process
7 remains consistent throughout the duration of the program.

8
9 **III. CONCLUSIONS AND RECOMMENDATIONS**

10 **Q. Please summarize your conclusions and recommendations to the Commission.**

11 **A.** I recommend that the Commission:

- 12 • If it approves the Company's proposed modifications to its L2 and L1 rebates (i.e.,
13 allowing rebates to apply to NEMA 14-50 and 5-20 outlet installations), require the
14 Company to ensure that a customer who receives a rebate for a NEMA 14-50 or 5-20
15 outlet actually purchases or otherwise obtains an EV charger or charging cord, and
16 provides proof of EV purchase or lease;
- 17 • Approve the Company's proposed DCFC application requirements (i.e., security
18 lighting and number of ports);
- 19 • Direct the Company to increase the rebate per 150 kW DCFC port to \$70,000;
- 20 • Reject the Company's proposed DCFC program two-year time limitation and allow the
21 program to extend until depletion of program funding or for six years;
- 22 • Require the Company to provide an explicit definition of a "community" for DCFC
23 rebate eligibility; and

- 1 • Require the Company to propose a clear rubric and methodology by which it will
2 evaluate each DCFC rebate application.

3

4 **Q. Does that complete your testimony?**

5 A. Yes.

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 generation and distribution of) **Case No. U-21870**
electricity and for other relief.)
)

REBUTTAL TESTIMONY OF SOPHIA SCHUSTER

ON BEHALF OF

THE MICHIGAN ENERGY INNOVATION BUSINESS COUNCIL,

INSTITUTE FOR ENERGY INNOVATION,

AND

ADVANCED ENERGY UNITED

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1 **I. INTRODUCTION**

2

3 **Q. State your name, business name and address.**

4 A. My name is Sophia Schuster, and I am a Policy Principal with the Michigan Energy
5 Innovation Business Council (“Michigan EIBC”) and the Institute for Energy Innovation
6 (“IEI”), located at 115 West Allegan Street, Suite 710, Lansing, Michigan 48933.

7

8 **Q. On whose behalf are you appearing in this case?**

9 A. I am appearing here as an expert witness on behalf of Michigan EIBC, IEI, and Advanced
10 Energy United (“United”), collectively referred to as “MEIU.”

11

12 **Q. Are you the same Sophia Schuster who provided direct testimony in this proceeding?**

13 A. Yes, I am.

14

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

16 A. No, I am not sponsoring any exhibits.

17

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

19 A. The purpose of my rebuttal testimony is to respond to certain statements in the direct
20 testimony of Michigan Public Service Commission (“Commission”) Staff witness Kevin
21 S. Krause regarding the existing “demand charge holiday” for direct current fast chargers

1 (“DCFC”) and his proposal that the Company be required to introduce a new DCFC-
2 specific tariff in its next general electric rate case.

3
4 **II. REBUTTAL OF WITNESS KRAUSE**

5
6 **Q. Please describe the history of the so-called “demand charge holiday” currently in**
7 **effect.**

8 A. Consumers Energy Company’s (“Consumers” or “the Company”) General Service Primary
9 Rate GP is a distribution rate with no demand charge for large businesses taking service at
10 2,400 volts or greater.^{1, 2} As of January 1, 2021, this rate is closed to new business service
11 other than for service to DCFC charging stations.³ The rate includes energy charges for
12 power supply and distribution, differing by voltage level of connection, and a fixed
13 customer charge.⁴ In the Company’s 2023 general electric rate case (Case No. U-21389),
14 witness Krause asserted that “the provision that allows [DCFC] stations to be on rate GP

¹ Consumers Energy, “Primary Distribution Rates for Large Businesses,” accessed October 2025, available at <https://www.consumersenergy.com/business/account-and-billing/rates/electric-rates-and-programs/rate-plans/large-business>.

² Michigan Public Service Commission, Case No. U-21389, Order, March 2024, p. 112.

³ Michigan Public Service Commission, Case No. U-21585, Order, March 2025, p. 480.

⁴ Direct Testimony of Kevin Krause (“Krause Direct”), Case No. U-21389, p. 5.

1 is the Company’s version of a demand charge holiday,”⁵ but, due to current market
2 conditions, recommended that

3 the demand charge holiday be extended for currently operating [DCFC]
4 stations to June 1, 2026 [and that] for chargers energized after June 1, 2024,
5 the chargers should be allowed to remain on rate GP for two years.⁶
6

7 According to witness Krause, this would allow adequate time to build out a “skeleton
8 network of chargers,” at which point, DCFC stations on rate GP should be moved to either
9 rate GPD or GPTU, which are general service primary rates with demand charges.⁷ The
10 Company contended, however, that due to the immaturity of the market, it would be more
11 appropriate to revisit, rather than discontinue, the demand charge holiday in 2026.⁸ In Case
12 No. U-21389, the Commission ordered that:⁹

- 13 • The demand charge holiday be extended until June 1, 2026;
- 14 • DCFC stations energized after June 1, 2024 be allowed to remain on Rate GP for two
15 years; and
- 16 • The Company conduct and present a study to evaluate the merits of a DCFC-specific
17 tariff in its next rate case.

18 In Case No. U-21585 (Consumers’ 2024 general electric rate case), Company witness
19 Jeffrey A. Myrom indicated that the limited number of DCFC and low utilization rates in

⁵ *Id.*, p. 6

⁶ *Id.*, p. 10.

⁷ *Ibid.*

⁸ Michigan Public Service Commission, Case No. U-21389, Order, March 2024, p. 114.

⁹ *Id.*, pp. 114-115.

1 the Company’s service territory was making it difficult to establish a reliable DCFC load
2 shape on which to base a DCFC-specific tariff.¹⁰ This issue was not discussed further in
3 the Commission’s order in Case No. U-21585.

4
5 **Q. In the current case, what does Commission Staff witness Kevin Krause suggest**
6 **regarding the so-called “demand charge holiday”?**

7 A. In a discussion regarding the future of the so called “demand charge holiday,” witness
8 Krause indicates that

9 Under rate GP, charging stations are treated as if increasing charging speed
10 has no incremental impact on cost causation, such as increased
11 infrastructure. As charging stations increase in speed and demand, the GP
12 rate becomes less and less appropriate. Stations on rate GP are clearly
13 receiving a subsidy. Staff recommends that rate GP should be closed to
14 both new and existing fast charging stations on June 1, 2028.¹¹
15

16 **Q. Do you agree that EV charging station operators on Rate GP – and thus also their**
17 **paying customers – are receiving a subsidy?**

18 A. Not necessarily, and almost certainly not when considered in the context of EV-derived
19 revenues in the aggregate. As detailed in my direct testimony and references therein, DCFC
20 are essential to enabling long-distance travel and are critical for reducing range anxiety for
21 new customers, making them a key enabling technology for broad EV adoption.¹²

¹⁰ Direct Testimony of Jeffrey A. Myrom on behalf of Consumers Energy Company (“Myrom Direct”), Case No. U-21585, p. 8.

¹¹ Krause Direct, Case No. U-21870, p. 4.

¹² Direct Testimony of Sophia Schuster on behalf of the Michigan Energy Innovation Business Council Institute for Energy Innovation, and Advanced Energy United (“Schuster Direct”), Case No. U-21870, pp. 22, 24–25, 30.

1 Moreover, as utilities continue to invest in EV programs, the resultant increased EV
2 adoption actually leads to downward rate pressure for all ratepayers.¹³

3
4 However, DCFC are more expensive to install and, at least until utilization rates are high,
5 the return on investment for this equipment will remain low, making it difficult to establish
6 a workable business case for these investments. Demand charges based on peak usage can
7 add to these costs and further erode the business case for DCFC, especially where
8 utilization is currently low.¹⁴ In fact, as MEIU witness Dr. Laura Sherman noted in rebuttal
9 testimony in Case No. U-21297 (DTE Electric Company’s 2023 general electric rate case),

10 demand charges have been recognized across the country as a barrier to the
11 deployment of high-powered EV charging stations (e.g., DCFC or clustered
12 Level 2 charging stations).¹⁵
13

14 In direct testimony in the current case, Walmart, Inc. witness Matthew Lyon echoes these
15 points, noting that

16 Walmart understands how EV charging rates can either promote or impede
17 EV charging investment and user experience. While the EV industry
18 continues to grow, there will still be a ramp-up to sufficient EV adoption to
19 support an extensive public EV charging network. This will create
20 geographical locations where public EV chargers are either not being used
21 or are used infrequently. For these under-utilized chargers that are being
22 billed by the utility under a more traditional rate tariff with a demand
23 charge, the charger operator may be assessed the maximum demand charge
24 even after only a single use of that charging unit regardless of whether there
25 is any additional charging during that month. This outcome negatively

¹³ Frost, J. et al., Synapse Energy Economic, Inc. “Electric Vehicles Are Driving Electric Rates Down,” June 2020, available at https://www.synapse-energy.com/sites/default/files/EV_Impacts_June_2020_18-122.pdf.

¹⁴ Great Plains Institute and Midcontinent Transportation Electrification Collaborative, “Analytical White Paper: Overcoming Barriers to Expanding Fast Charging Infrastructure in the Midcontinent Region,” July 2019, available at https://scripts.betterenergy.org/reports/GPI_DCFC_Analysis_July_2019.pdf.

¹⁵ Rebuttal Testimony of Dr. Laura Sherman on behalf of the Michigan Energy Innovation Business Council Institute for Energy Innovation, and Advanced Energy United, Case No. U-21297, p. 3.

1 impacts the economics for that unit and may lead to little or no third-party
2 investment in public EV chargers sited in areas of initial low usage.¹⁶
3

4 Given this reality, billing DCFC with low utilization rates under a tariff with a demand
5 charge is, in fact, likely to be *overcharging* on a cost-of-service basis. Furthermore, as
6 detailed in my direct testimony,¹⁷ there is mounting evidence that load from EV charging
7 customers as a whole contributes much less to system peaks when compared to other
8 commercial and industrial customers, and that the revenue attributable to EV charging
9 exceeds the cost of service over time. In other words, EV charging customers may actually
10 be subsidizing rates of utility customers who do not own EVs or use EV charging.
11

12 If demand charges are nonetheless instituted for DCFC, the resultant hesitance from third
13 party operators to invest in public DCFC in areas where utilization may initially be low
14 could, subsequently, exacerbate existing infrastructure gaps and risk never establishing the
15 desired “skeleton network.”¹⁸ Additionally, to the extent that DCFC are not deployed
16 because of demand charges, this will likely depress overall EV adoption, which will in turn
17 depress incremental revenue from EV charging.

¹⁶ Direct Testimony of Matthew Lyon on behalf of Walmart, Inc. (“Lyon Direct”), Case No. U-21870, p. 26.

¹⁷ Schuster Direct, pp. 31-33.

¹⁸ Rebuttal Testimony of Nicholas M. Revere on behalf of Michigan Public Service Commission Staff, Case No. U-21585, p. 3.

1 **Q. What does witness Krause suggest the Company do to prepare in the event that the**
2 **Commission accepts witness Krause’s proposed “demand charge holiday” sunset on**
3 **June 1, 2028?**

4 A. In preparation for his recommended closure of Rate GP to all new and existing customers
5 on June 1, 2028, witness Krause suggests next steps for the Company and the Commission,
6 recommending that

7 the Company introduce a new tariff for fast charging in its next rate case
8 based on available fast charging data...based on cost-of-service. Since
9 there would likely be a preference for an energy only rate, with no demand
10 charges, Staff would like to see this incorporated into the proposal. Staff
11 also recommends that the utility provide rate design options considering
12 charging station uptime and charging reliability.¹⁹
13

14 **Q. Do you agree with the recommendation to sunset the “demand charge holiday” on**
15 **June 1, 2028?**

16 A. Not entirely. Put simply, demand charges are unreasonable until utilization rates are high
17 enough such that DCFC operators are not overcharged on a cost-of-service basis. Billing
18 DCFC operators under a tariff that utilizes a demand charge risks suppressing third party
19 investment in areas where utilization may initially be low and, consequently, delays the
20 realization of the desired “skeleton network.”²⁰ Only once more DCFC are energized and
21 their utilization rates increase and stabilize will it be appropriate to sunset the “demand
22 charge holiday” and determine the suitability of a DCFC-specific tariff.
23

¹⁹ Krause Direct, pp. 4-5.

²⁰ Rebuttal Testimony of Nicholas M. Revere on behalf of Michigan Public Service Commission Staff, Case No. U-21585, p. 3.

1 Fortunately, the network of DCFC stations across the state is expected to expand
 2 significantly between 2026 and 2028. The Michigan Department of Transportation
 3 announced its Round 1 selections for sites supported by the National Electric Vehicle
 4 Infrastructure (“NEVI”) program in June 2024,²¹ and Round 2 selections were announced
 5 in June 2025.²² With 84 sites selected across the state,²³ only two are currently operational
 6 from Round 1 – the first having come online in December 2024 in Lansing²⁴ and the second
 7 in 2025 in Grand Rapids.²⁵ However, of the 84 total sites, two are complete, four are
 8 currently under construction (three of which are in the Company’s service territory), 23 are
 9 in the design phase (13 of which are in the Company’s service territory), and 53 have sites
 10 selected and are awaiting contracts (33 of which are in the Company’s service territory).²⁶
 11 Given the time between NEVI award selections and energization, it is reasonable to assume
 12 that many of these NEVI-supported DCFC stations will come online in the next two years.
 13 In addition to DCFC sites supported by the NEVI program, privately supported DCFC

²¹ Michigan Department of Transportation, “NEVI Round 1 selection results,” June 2024, available at <https://www.michigan.gov/mdot/-/media/Project/Websites/MDOT/Business/Contractors/Innovative-Contracting/NEVI/Round-1-Notification-of-Selection.pdf?rev=179bc81b311441d490d04950775e6fe9&hash=302C7A01C202CF290C3FF8FD15AD82C8>.

²² Michigan Department of Transportation, “NEVI Round 2 selection results,” June 2025, available at <https://www.michigan.gov/mdot/-/media/Project/Websites/MDOT/Business/Contractors/Innovative-Contracting/NEVI---2/Notification-of-Selection.pdf?rev=6451b2352ab14cd2a84a075496f62c6f&hash=12DC631641D6A886192976DBDA00C8D8>.

²³ Michigan Department of Transportation, “Michigan NEVI Project Status,” accessed September 2025, available at <https://experience.arcgis.com/experience/0f0eafe4cefe43a0adb8104d600d3cd3/page/Home/?views=Layers>.

²⁴ Michigan Department of Transportation, “MDOT announces first fast charging station under NEVI program live in Lansing,” December 2024, available at <https://www.michigan.gov/mdot/news-outreach/pressreleases/2024/12/11/mdot-announces-first-fast-charging-station-under-nevi-program-live-in-lansing>.

²⁵ Michigan Department of Transportation, “Michigan NEVI Project Status,” accessed September 2025, available at <https://experience.arcgis.com/experience/0f0eafe4cefe43a0adb8104d600d3cd3/page/Home/?views=Layers>.

²⁶ *Ibid.*

1 installations are also expected to continue to grow between 2026 and 2028. For example,
2 in November 2024, EVgo, a national charging provider, announced that it planned to
3 expand its partnership with Meijer by deploying 480 new public fast chargers at Meijer
4 properties across several states, including Michigan.²⁷ EVgo expects to open 30 new
5 stations at Meijer stores by the end of 2026, and another 30 by the end of 2027.²⁸ While
6 utilization may take time to stabilize at each of these new DCFC stations, they will serve
7 as useful new data points for the Company to better inform an appropriate “demand charge
8 holiday” sunset timeline and determine the suitability of a DCFC-specific tariff in the
9 future.

10
11 Second, as noted above, prematurely implementing a sunset to the “demand charge
12 holiday” by requiring DCFC customers to move off Rate GP could result in higher
13 operating costs, thus deterring future DCFC development and private investment in
14 Michigan communities. As noted by witness Lyon, Walmart and other third party DCFC
15 operators

16 [seek] to balance the risks and costs of installing and maintaining a
17 particular EV [DCFC] station, which is informed, in part, by the tariff under
18 which the electricity is provided from the utility to the owner of the EV fast
19 charging station.²⁹
20

²⁷ EVgo Fast Charging, “EVgo and Meijer Expand Partnership to Install up to 480 New Fast Charging Stalls at Meijer Locations Across Midwest,” November 2024, available at <https://www.evgo.com/press-release/evgo-and-meijer-expand-partnership-to-install-up-to-480-new-fast-charging-stalls-at-meijer-locations-across-midwest/>.

²⁸ *Ibid.*

²⁹ Lyon Direct, Case No. U-21870, p. 25.

1 Witness Lyon suggests that the electric rates available to customers can help to inform third
2 party operators, like Walmart, as to whether they should site a DCFC station at a particular
3 facility.³⁰ Given the relationship between the deployment of public charging and EV
4 adoption detailed in my direct testimony, slowing DCFC deployment could have a
5 significant negative impact on EV adoption in the Company's service territory.³¹
6 Subsequently, as detailed in my direct testimony, it could also impede the realization of net
7 benefits to all ratepayers resulting from increased EV charging.³²

8
9 Finally, hampering DCFC deployment would also reduce the amount of valuable usage
10 data for the Company to analyze in a future cost-of-service study ("COSS"), again leaving
11 any future COSS inaccurate and vulnerable to small demand swings. In other words, the
12 opportunity for DCFC stations to remain on Rate GP more readily actualizes net benefits
13 to all ratepayers and increases the amount of data available to the Company to use in future
14 COSS assessments, thus ensuring a more reliable COSS.

15
16 **Q. What do you suggest regarding the recommendation to sunset the "demand charge**
17 **holiday" on June 1, 2028?**

18 A. While I do agree with witness Krause that these are important issues for the Company to
19 evaluate and study and that at some point it may be necessary to sunset the "demand charge
20 holiday," the market is still developing. As stated above, more DCFC are expected to be

³⁰ *Ibid.*

³¹ Schuster Direct, pp. 25-26.

³² Schuster Direct, pp. 30-32

1 energized in the Company’s service territory before 2030, which will serve as critical data
2 points for the Company to evaluate in developing a well-informed sunset timeline and
3 determining the suitability of implementing a cost-of-service based DCFC-specific tariff.
4 At minimum, the Commission should not establish a “demand charge holiday” sunset date
5 until the Company has filed the findings of an accurate DCFC COSS and interested
6 stakeholders have had the opportunity to review and comment on the study’s findings.
7 Until then, I recommend that the Commission reject witness Krause’s recommendations to
8 remove new and existing DCFC customers from Rate GP on June 1, 2028.

9
10 **Q. Do you agree with the recommendation that the Company propose a DCFC-specific**
11 **tariff in its next general electric rate case?**

12 No. While the number of DCFC stations deployed has increased, the small sample size still
13 makes any usage analysis sensitive to swings caused by individual customers.^{33, 34}
14 Moreover, EV adoption and public charging utilization have not yet reached a steady state.
15 In Case No. U-21534 (DTE Electric Company’s 2024 general electric rate case), MEIU
16 witness Dr. Laura Sherman indicated that

17 Given the immaturity of the market, the current usage of these sites likely
18 does not represent the expected utilization rate in coming years as EV
19 deployment increases until it reaches an eventual point of consistent uptake
20 (e.g., a certain market equilibrium). These DCFC sites likely have
21 individual customer and class peak demands that may approximate what
22 those demands will be with increased EV deployment, but the total energy
23 usage at these sites is currently significantly less than what it will be in the
24 future. As such, [while DCFC usage has likely increased,] present revenue

³³ Myrom Direct, Case No. U-21585, p. 8.

³⁴ Lyon Direct, p. 26.

1 requirements per kWh of DCFC are likely still well above those that will be
2 required in the future.³⁵
3

4 It remains true that DCFC deployment and usage are not yet to the point to yield sufficient
5 data that would allow the Company to develop, or the Commission to rule on, an informed
6 DCFC-specific tariff.
7

8 Furthermore, given the limited number of DCFC and low utilization rates, it has not been
9 possible for the Company to develop an accurate DCFC COSS. These facts have not yet
10 materially changed and, as discussed above, it will likely not be possible for the Company
11 to complete an accurate DCFC COSS until more stations are deployed and utilization rates
12 increase. As such, it would be premature and unreasonable to require the Company to
13 propose a DCFC-specific tariff in its next general electric rate case.
14

15 **Q. What do you suggest regarding the recommendations to propose a new tariff for fast**
16 **charging in its next rate case?**

17 A. Given that EV adoption and therefore EV charging utilization rates have not yet reached a
18 steady state to inform the Company of an appropriate DCFC tariff, I recommend that the
19 Commission reject witness Krause’s recommendations to require the Company to file a
20 DCFC tariff in its next general electric rate case.
21

³⁵ Direct Testimony of Dr. Laura Sherman on behalf of the Michigan Energy Innovation Business Council Institute for Energy Innovation, and Advanced Energy United (“Sherman U-21534 Direct”), Case No. U-21534, p. 52.

1 However, I do agree with witness Krause that these are important issues for the Company
2 to evaluate and study. As such, I recommend that the Commission require the Company to
3 conduct a comprehensive evaluation of best practices as it relates to DCFC tariffs being
4 implemented in other states and countries. To adequately inform its evaluation, the
5 Company should conduct a stakeholder convening to gather key stakeholder and industry
6 feedback on issues related to DCFC tariffs and demand charges, as suggested by Walmart
7 witness Matthew Lyon.³⁶ The Commission should then require Consumers by a reasonable
8 later date (*e.g.*, December 1, 2026) to present its findings and propose a long-term plan for
9 the eventual implementation of an appropriate DCFC tariff. These discussions, coupled
10 with the new data available from DCFC stations energized in the coming years, should
11 enable the Company to conduct a more comprehensive COSS to inform whether a future
12 DCFC-specific rate proposal is suitable and, if so, determine an appropriate tariff structure.

13
14 **Q. Do you have any other concerns with regards to “demand charge holiday” sunset**
15 **timelines that witness Krause proposes?**

16 A. Yes. As previously stated, witness Krause recommends that “rate GP should be closed to
17 both new and existing [DCFC] stations on June 1, 2028.”³⁷ If the Commission adopted this
18 recommendation, a DCFC station in the Company’s service territory energized on June 1,
19 2027 would only be able to enroll in Rate GP for one year. However, this recommendation
20 is inconsistent with the Commission’s previous Order in the Company’s 2023 general

³⁶ Lyon Direct, Case No. U-21870, p. 26.

³⁷ Krause Direct, Case No. U-21870, p. 4.

1 electric rate case (U-21389)³⁸, which allowed for a two-year rolling provision wherein
2 DCFC stations energized at least through inside two years from June 1, 2028 (*i.e.*, between
3 June 1, 2026 and May 31, 2028) would be eligible to remain on the “demand charge
4 holiday” rate for two years.

5
6 **Q. What do you recommend with respect to DCFC stations energized inside two years**
7 **of witness Krause’s proposed “demand charge holiday” sunset timeline?**

8 A. If the Commission determines that a concrete sunset date is absolutely necessary despite
9 the arguments of prematurity presented above, the Commission should, at minimum,
10 maintain consistency and allow DCFC stations energized between June 1, 2026 and May
11 31, 2028 to remain on Rate GP for two years, even if that end-date is after the proposed
12 June 1, 2028 demand charge waiver sunset. In other words, the sunset should only be with
13 respect to the two-year start date for a customer to enroll in the tariff.

14
15 **III. CONCLUSIONS AND RECOMMENDATIONS**

16
17 **Q. What do you recommend to the Commission?**

18 A. In addition to the recommendations contained in my direct testimony,³⁹ I recommend that
19 the Commission:

- 20 • Reject witness Krause’s recommendation to remove new and existing DCFC station
21 customers from Rate GP on June 1, 2028;

³⁸ Michigan Public Service Commission, Case No. U-21389 Order, March 2024, p. 113.

³⁹ Schuster Direct, pp. 50-51.

- 1 • If the Commission does establish June 1, 2028 as the “demand charge holiday” sunset,
2 allow DCFC site hosts energized between June 1, 2026 and May 31, 2028 to remain on
3 Rate GP on a two-year rolling basis; and
- 4 • Require the Company to conduct a comprehensive evaluation with stakeholder input
5 of best practices as it relates to DCFC tariffs being implemented in other states and
6 countries. The Company should present its findings, a discussion of the suitability of a
7 DCFC-specific tariff, and, if appropriate, a long-term plan for the implementation of
8 an appropriate DCFC tariff by December 1, 2026.

9

10 **Q. Does that complete your rebuttal testimony?**

11 **A. Yes.**

1 MR. OOMS: Thank you, Your Honor. The next
2 Brett Sproul. He filed only direct testimony in this
3 case, which consists of a cover page, a table of contents,
4 and 25 pages of questions and answers. With his direct
5 testimony, he sponsored Exhibits MEIU-2.1 through Exhibits
6 MEIU-2.13, before the binding in admission of those --
7 that testimony and those exhibits at this time.

8 JUDGE THOITS: Are there any objections to the
9 admission to this testimony or these exhibits?

10 Hearing none. The direct testimony of Brett
11 Sproul is bound in the record and Exhibits MEIU-2.1
12 through MEIU-2.13 are admitted.

13

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ADVANCED ENERGY UNITED

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1 **I. INTRODUCTION AND QUALIFICATIONS**

2
3 **Q. Please state your name and business address.**

4 A. My name is Brett Sproul. My business address is 1801 Pennsylvania Avenue NW, Suite
5 410, Washington, DC 20006.
6

7 **Q. What is your current occupation?**

8 A. I am employed by Advanced Energy United, Inc. (“United”) as a Regulatory Policy
9 Principal for the central region states where United is active. This includes Illinois,
10 Indiana, Michigan, and Wisconsin.
11

12 **Q. On whose behalf are you testifying?**

13 A. I am testifying on behalf of the Michigan Energy Innovation Business Council (“Michigan
14 EIBC”), the Institute for Energy Innovation (“IEI”), and United, collectively referred to as
15 “MEIU.”
16

17 **Q. Please describe your educational and professional background.**

18 A. I hold a Bachelor of Science degree in Environmental Science and Policy with a
19 concentration in Environmental Economics from the University of Maryland – College
20 Park. I have previously worked at the Maryland Public Service Commission serving both
21 as a Regulatory Economist within the Maryland Commission’s Technical Staff and as a
22 Technical Advisor to the commissioners at the Maryland Public Service Commission. I
23 have also worked as a Policy Intern at the U.S. Department of Energy, Office of Small and
24 Disadvantaged Business Utilization and as a Research Intern at the U.S. Department of

1 Agriculture, Sustainable Agricultural Systems Laboratory. The full extent of my
2 educational and professional background can be found in my résumé, attached as Exhibit
3 MEIU-2.1.

4
5 **Q. Have you provided testimony to a state public service commission in the past?**

6 A. Yes. I have provided testimony to the Maryland Public Service Commission in Delmarva
7 Power and Light Company's application for a multi-year rate plan in Case No. 9681.

8
9 **Q. Are you offering any exhibits with your testimony?**

10 A. Yes. I am offering the following exhibits:

- 11 • Exhibit MEIU-2.1: Résumé of Brett Sproul
- 12 • Exhibit MEIU-2.2: Discovery Response GLREA-CE-0284
- 13 • Exhibit MEIU-2.3: 2022 Cadmus Study in Case No. 21410, Exhibit No. A-9 (JRB-
14 3)
- 15 • Exhibit MEIU-2.4: Discovery Response MEIU-CE-0389
- 16 • Exhibit MEIU-2.5: Discovery Response MEIU-CE-0378
- 17 • Exhibit MEIU-2.6: Discovery Response MEIU-CE-0379
- 18 • Exhibit MEIU-2.7: Discovery Response MEIU-CE-0388
- 19 • Exhibit MEIU-2.8: Discovery Response MEIU-CE-0259
- 20 • Exhibit MEIU-2.9: Discovery Response MEIU-CE-0377_ATT_3
- 21 • Exhibit MEIU-2.10: Discovery Response MEIU-CE-0380
- 22 • Exhibit MEIU-2.11: Discovery Response MEIU-CE-0381_ATT_1
- 23 • Exhibit MEIU-2.12: Discovery Response MEIU-CE-0381

- Exhibit MEIU-2.13: Discovery Response MEIU-CE-0377

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to offer my analysis and recommendations on Consumers Energy Company's (the "Company" or "Consumers") proposals related to its Demand Response ("DR") programs. I present my concerns with the proposals provided by the Company regarding its Residential Dynamic Peak Pricing ("DPP") program, specifically related to customer demand savings values and bill credit values.

II. DR PROGRAMS OVERVIEW

Q. How does Consumers define DR?

A. Consumers' witness Alex Gast states in his direct testimony that:

"DR programs help manage capacity need for peak demand, in lieu of additional supply-side electric generation or capacity contracts. Ultimately, the Company's DR programs help balance Michigan's electricity needs to help protect the grid, react to emergencies and severe weather, and avoid the cost of additional generation infrastructure to serve peaks."¹

Furthermore, witness Gast states that:

"Demand-side resources such as DR are essential to meeting climate goals and achieving the MWs approved in the IRP. The DR program remains essential to the Company's long-term ability to achieve greater flexibility and improved sustainability over the long term."²

¹ Direct Testimony of Alex Gast on behalf of Consumers Electric Company ("Gast Direct"), Case No. U-21870, pp. 6–7.

² *Id.*, p. 7.

1 **Q. Does the definition of DR provided by the Company align with industry definitions?**

2 A. Yes, Consumers’ definition of DR and DR programs is generally aligned with industry
3 definitions, especially regarding the importance of DR to meeting clean energy goals and
4 achieving flexibility and sustainability over the long-term. It may also help to consider a
5 description offered by Lawrence Berkeley National Laboratory: “Demand response
6 happens when a utility, aggregator or grid operator enables electricity customers to change
7 their power consumption through financial or other incentives.”³

8
9 **Q. What is the value of DR programs?**

10 A. As stated above, the ultimate goal of DR is to help balance electricity needs to help protect
11 the grid, react to emergencies and severe weather, and avoid the cost of additional
12 generation infrastructure to serve peaks. DR programs are also important for both electric
13 utility customers and the electric utility itself. For instance, on the customer-side, DR
14 programs utilizing time-of-use rates can allow a customer to realize significant utility bill
15 savings due to the reduction in electricity usage during times of peak electricity demand
16 when electricity prices are highest. Additionally, some DR programs can also benefit
17 customers via utility-provided bill credits for actively participating in a DR program. On
18 the utility-side, as mentioned, DR programs can assist a utility’s efforts in balancing
19 electricity capacity during peak demand hours and reduce the need for distribution or
20 supply-side investments, thus reducing the cost to supply electric service to customers.

21

³ Lawrence Berkeley National Laboratory, *Demand Response Research Center*, available at <https://buildings.lbl.gov/demand-response>.

1 **Q. What DR programs does Consumers currently operate?**

2 A. As discussed in Company witness Gast’s direct testimony, Consumers currently operates
3 three residential customer DR programs and two commercial & industrial (“C&I”)
4 customer DR programs, for a total of five DR programs across the entirety of Consumers’
5 operations.⁴

6
7 The Company’s residential customer DR programs consist of 1) the Device Cycling
8 program, 2) the DPP program, and 3) the Smart Thermostat program. Through the Device
9 Cycling program, the Company installs direct load control switches on a customers’ high
10 energy use appliances (such as air conditioning units) in order to control appliances’ energy
11 usage during periods of high demand. The DPP program consists of two pricing options –
12 the Critical Peak Pricing (“CPP”) program and the Peak Time Rewards (“PTR”) program
13 – which are designed to encourage reduced energy use during periods of high demand. The
14 Smart Thermostat program allows the Company to utilize select wi-fi enabled Smart
15 Thermostats in customers’ homes to optimize the use of air conditioning units during
16 periods of high demand.

17
18 The C&I DR programs consist of 1) the Business DR Contractual Payment program and
19 2) the Business DR Rate Options. Through the Business DR Contractual Payment program,
20 the Company provides a payment, based on a contractual agreement, to a business to reduce
21 electricity load by a specific amount during Midcontinent Independent System Operator
22 (“MISO”) emergencies. The Business DR Rate Options consists of four different types of

⁴ Gast Direct, p. 4.

specific rate options that provide discounts with the intended purpose of incentivizing a business' reduction of electricity load during MISO emergencies.⁵

Q. What is the current status of Consumers' DR programs?

A. Table 1 below provides the number of participants and the megawatt ("MW") amount of enrolled capacity within each specific DR program offered by the Company.

Table 1: Demand Response Program Status⁶

Demand Response Program Status (2024 Data)		
Program	Program Participants	Enrolled Capacity (MW)
Residential Device Cycling	95,000	57.3
Residential Dynamic Peak Pricing Program	176,000	37.9
Residential Smart Thermostat	59,000	54.2
Business DR Contractual	1,402	249
Business DR Rate Options	39	259.5

Furthermore, Company witness Megan Metz estimates the impacts of DR programs within her direct testimony. When representing the impacts of different DR programs, witness Metz organizes DR programs into two categories: 1) programs that Consumers has direct control over, and 2) programs that are dependent upon customer behavioral choices.

⁵ The four different types of specific rate options include: 1) General Interruptible Service, 2) General Interruptible Service, 3) Rate Energy Intensive Primary Service, and 4) Long-Term Industrial Load Retention Rate Service. See Gast Direct, p. 4

⁶ Gast Direct, p. 4.

1 Programs that Consumers has direct control over are eligible to receive Zonal Resource
2 Credits (“ZRC”) from MISO as a capacity resource and include the following programs:
3 Residential Air Conditioning Peak Cycling, Residential Smart Thermostat, Business DR
4 Contractual Payments, and Business DR Rate Options.⁷ The estimated impact for these
5 programs are 651.4 ZRCs (valued at \$62 million) for planning year 2025/2026 and 684.3
6 ZRCs (valued at \$65 million) for planning year 2026/2027.⁸

7
8 Demand-side management programs (which includes DR programs) that are dependent
9 upon customer behavioral choices include: DPP, Energy Waste Reduction (“EWR”),
10 Conservation Voltage Reduction, and Residential Summer on-peak rates. The estimated
11 impact for these programs is 1,023 MW for planning year 2025/2026 and 1,114 MW for
12 planning year 2026/2027.⁹

13
14 **Q. How does Consumers currently recover the costs associated with operating its DR**
15 **programs?**

16 A. Costs associated with Consumers’ DR programs are allocated in the Company’s cost of
17 service study using the production capacity allocator 220 (4CP 75/0/25) which recognizes
18 that DR programs are a capacity resource that should be allocated in the same manner as
19 other capacity costs. This methodology is in-line with common best practices and is
20 consistent with the methodology that was previously approved by the Michigan Public

⁷ A Zonal Resource Credit is a capacity credit increment equal to 1 MW of generation resource that is awarded by MISO for a utility’s DR programs that are directed by the utility. See Direct Testimony of Megan Metz on behalf of Consumer Energy Company (“Metz Direct”), Case No. U-21870, pp. 19, 23.

⁸ Metz Direct, p. 24.

⁹ *Ibid.*

1 Service Commission (“Commission”) in Case No. U-21389. The Company is proposing to
2 continue the use of this methodology in the instant rate case.¹⁰

3
4 **Q. What is the revenue requirement that Consumers is requesting in the instant rate case**
5 **associated with its DR programs?**

6 A. The projected revenue requirement associated with DR programs for the test year ending
7 April 30, 2027 is calculated within the Company’s Exhibit A-83 (PDD-59).¹¹ As calculated
8 in Exhibit A-83 (PDD-59), the residential DR programs revenue requirement is
9 \$21,321,000, the C&I DR programs revenue requirement is \$22,251,000, and the total DR
10 programs revenue requirement is \$43,572,000.¹²

11
12 **Q. Is Consumers proposing any changes to its cost recovery methodology associated with**
13 **its DR programs?**

14 A. Yes, the Company is proposing to remove the total revenue requirement associated with
15 DR programs from base rates and instead collect the total DR programs revenue
16 requirement via a DR surcharge on customer bills.¹³ The revenue requirement would be
17 allocated among the following rate classes: residential, commercial secondary, lighting and
18 unmetered, primary, and rate General Self-Generation.¹⁴ The Company proposes to adjust
19 the surcharge through its annual DR reconciliation proceedings to account for changing

¹⁰ Direct Testimony of Emily Davis on behalf of Consumers Energy Company (“Davis Direct”), Case No. U-21870, p. 22

¹¹ Direct Testimony of Patrick Daly on behalf of Consumers Energy Company (“Daly Direct”), Case No. U-21870, p. 39.

¹² Consumers Energy Company Exhibit A-83 (PDD-59), Case No. U-21870, p. 1.

¹³ See Direct Testimony of Laura Connolly on behalf of Consumers Energy Company (“Connolly Direct”), Case No. U-21870, p. 14.

¹⁴ Consumers Energy Company’s Exhibit A-89 (EAD-5), Case No. U-21870, p. 1.

1 costs, over/under-recoveries, and recovery of the performance incentive rather than making
2 these adjustments through a rate case.¹⁵ The Company asserts that this proposal is
3 consistent with the Commission’s Order in Case No. U-21585 that approved the DR
4 surcharge methodology.¹⁶

5
6 **Q. What are the proposed DR surcharge amounts that are being proposed for different**
7 **individual customer classes?**

8 A. The proposed DR surcharge rate is calculated in Company witness Laura Connolly’s
9 Exhibit A-66 (LMC-5) at page 1. Of particular note, the DR surcharge rate for all
10 residential customer classes is proposed to be \$0.002009 per kilowatt-hour (“kWh”).

11
12 **Q. What is your position on the changes that Consumers is proposing to its cost recovery**
13 **methodology for its DR programs?**

14 A. Without more information about possible impacts from this change, I do not have a specific
15 position at this time. I do, however, recommend that the Commission’s decision in this case
16 on the DR surcharge methodology and process be appropriately aligned and consistent with
17 any Commission decisions made in the ongoing open docket to examine issues related to
18 rate case procedures in Case No. U-21637.¹⁷

19

¹⁵ Gast Direct, p. 8.

¹⁶ *Ibid.*

¹⁷ Michigan Public Service Commission Order, Case No. U-21637, July 10, 2025, p. 39. The Commission states that “The Staff proposes addressing DR in rate cases; and Consumers proposes retaining a combined annual DR plan and reconciliation proceeding that is separate from the rate case. The Commission seeks comment on both proposals.”

1 **III. DPP DR PROGRAM**

2
3 **Q. Please describe Consumers' DPP DR program.**

4 A. As noted above, the residential DPP program consists of two pricing options: the CPP
5 program and the PTR program. While the CPP and the PTR programs utilize different
6 approaches, both are focused on achieving the same goal: encouraging reduced energy use
7 during periods of high electricity demand. Consumers refers to periods of high electricity
8 demand, when it uses DR resources, as "DR Events."

9
10 The CPP program disincentivizes customer electricity use during DR Events by charging
11 a significantly higher rate (currently \$1.00 per kWh) for electricity use during the DR Event
12 time period (typically between 2 and 6 P.M.). In exchange for being subject to the high
13 \$1.00 per kWh rate, customers enrolled in the CPP program are offered a discounted rate
14 (typically a 10 to 20% reduced rate) during weekends, holidays, and all weekday hours
15 except for 2 p.m. to 7 p.m. As of August 18, 2025, there are 24,860 residential customers
16 enrolled in the CPP program (Exhibit MEIU-2.2).

17
18 The PTR program incentivizes reduced customer electricity usage during DR Events by
19 providing a bill credit to customers for reduced electricity use during the DR Event.
20 Specifically, the PTR program currently provides a bill credit of \$1 per kWh of electricity
21 that is reduced (compared to a customer's baseline usage on similar weather day
22 conditions) during the DR Event. As of August 18, 2025, there are 173,559 residential
23 customers enrolled in the PTR program (Exhibit MEIU-2.2).

24

1 **Q. How does the Company determine when to initiate a DR Event?**

2 A. DR Events are initiated by Consumers when forecasted 4-hour load capacity requirements
3 exceed 27,000 Megawatt-hours (“MWh”) in order to reduce the Planning Reserve Margin
4 Requirement (Exhibit MEIU-2.3). Customers enrolled in the DPP program are typically
5 given a day-ahead notice for each DR Event and each DR Event typically occurs between
6 2 p.m. and 6 p.m. (Exhibit MEIU-2.3). DR Events are initiated by Consumers rather than
7 in response to a MISO emergency, and Consumers can initiate a maximum of 14 DR Events
8 in a single year (Exhibit MEIU-2.3). For residential DR programs, Consumers typically
9 coordinates the dispatch of programs during declared DR Events but can dispatch
10 individual programs in the case of an economic event and not an emergency event (*i.e.*
11 during an economic crisis where constraint on the grid may be of less concern) (Exhibit
12 MEIU-2.4). According to Consumers, no DR Events have been called since 2022 (Exhibit
13 MEIU-2.5). In 2022, five DR Events were called on the following dates: June 15, June 21,
14 June 22, July 19, and July 21 (Exhibit MEIU-2.3).

15

16 **Q. How does Consumers communicate the likelihood of an upcoming DR Event to**
17 **participating customers?**

18 A. When Consumers forecasts for a DR Event, customers participating in the DPP program
19 will receive a notice before the DR Event occurs (typically one day ahead). Customers may
20 choose to receive the notice via text, voice alerts, and/or e-mail (Exhibit MEIU-2.3). In
21 2022, Consumers engaged in outreach efforts to phase-out phone call notifications for DR
22 Events and encouraged customers to opt for email or text message notifications of DR
23 Events (Exhibit MEIU-2.6). This outreach effort is aligned with the findings of the 2022

1 Cadmus Study which showed that DPP participants that received text or voice
2 communications delivered the largest kilowatt (“kW”) impacts (Exhibit MEIU-2.3).

3
4 **Q. How do customers benefit from participation in the DPP program?**

5 A. Customers that participate in the DPP Program realize two main benefits: 1) reduced
6 energy costs, and 2) greater control over their energy usage.¹⁸ Customers participating in
7 the DPP program can reduce their electricity costs by reducing their electricity usage during
8 DR Events and by receiving direct monetary benefits from the DPP program (either
9 through the PTR program bill credits or through the CPP program discounted rates). DPP
10 program participants also assert greater control over their energy usage and their electricity
11 bill by having the ability to adjust their usage during DR Events. For example, during a DR
12 Event, a DPP program participant can reduce their usage and realize extensive bill savings
13 as a result, whereas a non-DPP program participant may be unable to act in the same way.
14 In 2022, the average per customer demand savings was 0.171 kW for the CPP program
15 (with average summer bill savings of \$10.36) and 0.125 kW for the PTR program (with
16 average summer bill savings of \$9.12) (Exhibit MEIU-2.3).

17
18 **Q. What common characteristics do customers share that participate in the DPP
19 program?**

20 A. The DPP program has the highest rate of low-income customer enrollments relative to all
21 other DR programs that the Company offers.¹⁹ In 2022, 13% of customers enrolled in the

¹⁸ Gast Direct, p. 7.

¹⁹ Gast Direct, p. 14.

1 CPP and PTR programs were identified as “low-income,” where “low-income” was
2 generally defined as a customer that participated in payment assistance, Consumers
3 Affordable Resource for Energy program, or Income-Qualified EWR participation.²⁰
4 According to a discovery response (Exhibit MEIU-2.7), as of September 9, 2025, there are
5 2,255 low-income customers enrolled in the CPP program and 17,450 low-income
6 customers enrolled in the PTR program. Consumers has also determined that the PTR
7 program largely consists of “entry-level” DR program participants due to the program’s
8 high enrollment rate and low (comparatively to other DR programs) per customer demand
9 savings achieved.²¹

10
11 **Q. Please describe the 2022 Cadmus Study that Consumers uses to inform the DPP**
12 **programs.**

13 A. In 2022, the Company contracted with Cadmus, a third-party evaluator, to review its DPP
14 programs and evaluate the impact results of the DPP programs during the DR events that
15 occurred in 2022. Cadmus developed a study for the Company (herein referred to as the
16 “2022 Cadmus Study;” Exhibit MEIU-2.3. Company witness Gast states in his direct
17 testimony that, “The Company, working with its third-party evaluator Cadmus, predicted
18 a lower capability than the 2022 planning value previously used.”²² In a discovery response
19 providing more information about the 2022 Cadmus Study (Exhibit MEIU-2.8), the
20 Company stated, “In 2025, Cadmus conducted an analysis that applied the distribution of
21 impacts and bill credits from summer 2022 events to current program enrollment levels,”

²⁰ Exhibit MEIU-2.3. 2022 Cadmus Study, Case No. 21410 Exhibit No. A-9 (JRB-3), p. 42.

²¹ Gast Direct, p. 14.

²² *Ibid.*

1 and referred to a Cadmus-produced study on the Residential Dynamic Peak Pricing Impact
2 Results from 2022 that was provided as Exhibit No. A-9 (JRB-3) in Case No. U-21410.

3
4 The 2022 Cadmus Study focused on the following research objectives: 1) what is the
5 average kW reduction per participant, 2) what are the aggregate MW and MWh reductions
6 on Summer 2022 DR Event days, 3) how do the load impacts vary, and 4) how did DPP
7 participation affect customer bills during Summer 2022 (Exhibit MEIU-2.3). To
8 understand the programs and make recommendations to the Company, Cadmus analyzed
9 the average customer demand savings for the CPP and PTR programs across the five
10 different DR Events that occurred during the summer of 2022 (Exhibit MEIU-2.3). To
11 further analyze the data and identify trends in the programs, Cadmus segmented the CPP
12 and PTR program participants by dwelling type, income status, enrollment year, customer
13 type, communication channel, and receipt of an educational e-mail (Exhibit MEIU-2.3).

14
15 In the 2022 Study, Cadmus calculated average customer demand savings for each
16 individual DR Event during 2022 for the CPP and PTR programs, as well as capability
17 values for both the CPP and PTR programs. The “per customer demand savings” is best
18 understood as the amount of kW that an individual customer reduces their electricity usage
19 as a result of the incentive/disincentive associated with the CPP or PTR program. “Per
20 customer demand savings” is calculated using a difference-in-differences model
21 comparing usage of treatment and control groups and adjusted for potential confounding
22 factors such as hour and day fixed effects (Exhibit MEIU-2.8). The Company can analyze
23 historical data on the average per customer demand savings for past DR Events to develop

1 “capability values” for the CPP and PTR programs. “Capability values” represent the
2 estimated per customer impact of each program and, per the 2022 Cadmus Study, are
3 calculated based on a regression analysis of 2022 evaluated impacts against average
4 outdoor event temperature on that day (Exhibit MEIU-2.3). “Capability values” are used
5 to estimate the impact and effectiveness of the CPP and PTR programs. For program
6 design, Consumers currently uses “capability values” of 0.21 kW/customer for the PTR
7 program and 0.25 kW/customer for the CPP program.²³ In the 2022 Study, however,
8 Cadmus calculated customer demand savings capability values (with predicted capability
9 at 90 degrees F) at 0.18 kW for the CPP program and 0.13 kW for the PTR program. In
10 other words, the estimated per customer demand savings that Cadmus predicts will be
11 achieved through the PTR and CPP programs is lower than what the Company utilizes for
12 program design.

13
14 **Q. Did the 2022 Cadmus Study offer any recommendations?**

15 A. Yes. The 2022 Cadmus Study offered three of what it characterized as “recommendations”
16 concerning the DPP Program:

- 17 1. Under planning conditions of 90 degrees F, [Cadmus] predicts an
18 average per-participant performance of 0.18 kW for CPP and 0.13
19 kW for PTR. The assumed planning condition comes from average
20 Michigan temperatures 2pm – 6pm during peak-demand days in
21 MISO Load Resource Zone 7 from 2013 to 2021.
- 22 2. Consumers Energy should explore a mechanism to claim 50-60
23 MWh of EWR per DPP event.
- 24 3. Consumers Energy should encourage participants to select text
25 message alerts at enrollment and do a campaign with legacy
26 participants encouraging them to sign up for text alerts of Energy
27 Savings Events (Exhibit MEIU-2.3).

²³ Gast Direct, p. 13.

1
2 Regarding the customer demand savings capability values, the 2022 Cadmus Study also
3 recommended that Consumers:

4 review expected performance under planning conditions annually to ensure
5 that long term trends are accounted for appropriately if and when they occur
6 – especially if Consumers Energy plans to seek Zonal Resource Credits at
7 MISO (Exhibit MEIU-2.3).
8

9 These recommendations, as provided by Cadmus in the 2022 Study, are used by Consumers
10 to inform its proposals for the DPP program.
11

12 **Q. Please describe the 2025 Cadmus Presentation on PTR Alternative Settlement**
13 **Investigation (“Presentation”).**

14 A. On April 2, 2025, Cadmus provided a presentation to Consumers on the PTR program
15 (Exhibit MEIU-2.9). The Presentation primarily focused on analyzing the PTR program
16 and exploring different potential opportunities to improve program cost-effectiveness. The
17 Presentation stated that the primary benefit for the PTR program is fixed whether you call
18 events or not and consists of the ability to reduce demand if needed and avoid construction
19 or purchases from the grid. The Presentation applied the distribution of impacts and bill
20 credits from summer 2022 DR Events to current program levels and tested four different
21 alternative settlement approaches to improve the cost effectiveness of the PTR program.
22 As shown in Exhibit MEIU-2.9, the four different alternative settlement approaches
23 provided were:

- 24 1. Minimum Threshold – Establish a minimum threshold and only provide bill
25 credits if savings exceed a certain threshold (1 kWh is used as an example).

- 1 2. Cap on Credits – Establish a cap on the amount of credits, where, for example,
2 if a customer saves 22 kWh, the customer only receives credits for 5 kWh (5
3 kWh is used as an example).
- 4 3. Round Down – Savings are rounded down to the nearest integer, where, for
5 example, if a customer saves 1.88 kWh, the customer only receives credit for 1
6 kWh.
- 7 4. Reduced Incentive Rate – Lowering the \$/kWh bill credit payment rate (50%
8 reduction in incentive rate is used as an example).

9

10 As described in more detail within the Presentation, each alternative settlement approach
11 comes with pros and cons and it is specifically stated in the Presentation that “Reducing
12 incentives could improve the cost-effectiveness of events, *but potentially at expense of*
13 *diminished response by participants*” (emphasis added) (Exhibit MEIU-2.9).

14

15 **Q. Is Consumers proposing any changes to the CPP and PTR programs in the instant**
16 **rate case based on the 2022 Cadmus Study or the 2025 Cadmus Presentation?**

17 A. Yes. Consumers is proposing to reduce the expected per customer demand savings (aka the
18 “capability value”) for the PTR program from 0.21 kW/customer to 0.13 kW/customer and
19 for the CPP program from 0.25 kW/customer to 0.18 kW/customer based on the analysis
20 from the 2022 Cadmus Study.²⁴ In other words, the Company is proposing to reduce the
21 estimated per customer demand savings that the Company predicts will be achieved
22 through the PTR and CPP programs. The Company is also proposing to reduce the bill

²⁴ Gast Direct, p. 13.

1 credit offered by the PTR program from \$1.00/kWh of energy reduced to \$0.50/kWh of
2 energy reduced based on the analysis from the 2025 Cadmus Presentation.²⁵

3
4 Consumers states that it is proposing these changes to align with the research conducted by
5 Cadmus, which predicted a lower customer demand savings capability value for the CPP
6 and PTR programs.²⁶ As detailed in Exhibit MEIU-2.8, Consumers asserts that the main
7 reason for proposing these changes is to improve the cost-effectiveness of the CPP and
8 PTR programs. Consumers specifically utilized the 2025 Presentation as the origin for
9 proposing a 50% reduction in PTR program bill credits in the instant rate case; however, it
10 is important to note that the Presentation does specifically ask a crucial question regarding
11 reduced incentives stating, “Will customer take the same amount of action for half the
12 money?” (Exhibit MEIU-2.9).

13
14 **Q. Is Consumers proposing any changes to the PTR program’s customer enrollment**
15 **incentives or marketing activities?**

16 A. For the PTR program, the Company is also proposing to discontinue customer enrollment
17 incentives and shift to low-cost marketing channels for the PTR program, including the use
18 of Consumers’ website during the time of a customer’s move-in.²⁷

²⁵ *Ibid.*

²⁶ *Id.*, p. 14.

²⁷ Gast Direct, p. 15.

1 **Q. What cost-effectiveness considerations does Consumers focus on for the DPP**
2 **program?**

3 A. Consumers has a central focus on improving the cost-effectiveness of the PTR program
4 and DR programs as a whole. Regarding DR programs, within his direct testimony,
5 Consumers' witness Gast states, "The Company has taken efforts to reduce costs and
6 increase MWs," and, "[T]he Company seeks to expand DR opportunities in the most cost-
7 effective ways."²⁸ In a discovery response (Exhibit MEIU-2.10), the Company stated that
8 it "includes a benefit-cost analysis in each of its annual Demand Response reconciliation
9 filings." The Company also provided the benefit-cost analysis that was conducted on the
10 DPP program for its 2024 DR Reconciliation (Exhibit MEIU-2.11) and stated in a separate
11 discovery response (Exhibit MEIU-2.12) that for this analysis "the Company compares the
12 levelized cost of the program to 75% of Cost of New Entry ("CONE"), which is considered
13 the primary benefit of the demand response program." Based on the 2024 benefit-cost
14 analysis provided by the Company (Exhibit MEIU-2.11), the DPP program exhibits the
15 lowest levelized cost of all of the DR programs listed in the analysis with a levelized cost
16 of \$24,491 per MW. The other programs listed in the analysis are the Device Cycling
17 program with a levelized cost of \$193,671 per MW, the Smart Thermostat program with a
18 levelized cost of \$134,565 per MW, and the C&I programs with a levelized cost of \$53,147
19 per MW. Furthermore, when comparing the levelized cost and the 75% CONE benefits,
20 both weighted for the amount of MISO-registered MW (of which the DPP program used a
21 proxy of 70% enrolled MW), the results showed that the DPP program exhibited total net
22 benefits for 2024 with a shared difference (based on 50% of savings shared) between costs

²⁸ Gast Direct, p. 7.

1 and benefits of \$927,554. In contrast, the Device Cycling program showed a difference
2 between costs and benefits of -\$2,163,045 and the Smart Thermostat program showed a
3 difference between costs and benefits of -\$823,484 (negative numbers indicating that both
4 programs exhibited net costs). Similar to the DPP program, the C&I programs also
5 exhibited net benefits with a difference between costs and benefits of \$8,871,376.

6
7 **Q. Do you agree with Consumers' proposal to reduce the per customer demand savings**
8 **values for the CPP and PTR programs?**

9 A. No. I believe that these values may be inaccurate and unrepresentative of the current CPP
10 and PTR programs. To make this proposal, Consumers utilizes customer demand savings
11 capability values calculated in the 2022 Cadmus Study. The usage of data from three years
12 ago to establish the customer demand savings values for the CPP and PTR programs in
13 2025 and the indefinite future is inappropriate and could lead to decisions that undermine
14 the success of the DPP program. To calculate the customer demand savings capability
15 values being proposed by Consumers, Cadmus utilized data from five DR events in 2022
16 with an average enrollment level of 14,117 participants for the CPP program and 77,019
17 participants for the PTR program (Exhibit MEIU-2.3). Relying on 2022 data to inform the
18 DPP program in 2025 is inherently flawed. DPP program levels have nearly doubled since
19 2022, as there are now 24,860 participants enrolled in the CPP program and 173,559
20 participants enrolled in the PTR program (Exhibit MEIU-2.2). Company witness Gast even
21 acknowledges this enrollment growth in the DPP program within his direct testimony by
22 stating that "the Company has seen a higher enrollment rate for PTR compared to other

1 DR offerings with 153,147 cumulative enrollments in 2024.”²⁹ Due to these vastly different
2 enrollment levels between 2022 and 2025, it is reasonable to assume that the per customer
3 demand savings values will likely differ between 2022 and 2025.

4
5 Furthermore, Cadmus specifically recommended that the Company review expected
6 performance under planning conditions annually to ensure long-term trends are accounted
7 for appropriately if and when they occur (Exhibit MEIU-2.3). However, in a discovery
8 response (Exhibit MEIU-2.5), the Company stated that it “has not undertaken this review
9 since 2022” and that “no events have been called since 2022. Therefore, performance
10 reviews have not been an opportunity.” In other words, Cadmus recommended an annual
11 review of expected performance in order to keep the DPP program capability values
12 updated and accurate, but the Company has not conducted this review. This supports my
13 point that the Company’s proposed changes to the customer demand savings capability
14 values for the CPP and PTR programs lack a reasonable basis. Furthermore, the fact that
15 the Company is proposing to make changes to the DPP program when there has not been
16 a DR event to analyze since 2022 provides justification that the Company’s proposals may
17 be inaccurate and unsubstantiated.

18
19 **Q. What recommendations do you have for the Commission regarding per customer**
20 **demand savings values for the PTR and CPP programs?**

21 **A.** I recommend that the Commission reject Consumers’ proposal to reduce the per customer
22 demand savings values for the PTR and CPP programs until the Company conducts an

²⁹ Gast Direct, p. 14.

1 updated analysis and review of the PTR and CPP programs’ expected performance under
2 current planning conditions.

3
4 **Q. How does Consumers propose to change the PTR Program bill credits in this case?**

5 A. The Company is proposing to reduce the bill credit offered by the PTR program from
6 \$1.00/kWh of energy reduced to \$0.50/kWh of energy reduced. This is based on the
7 Cadmus 2025 Presentation that suggested a 50% reduction in PTR program bill credits to
8 achieve greater cost-effectiveness. However, the Presentation does specifically ask a
9 crucial question regarding reduced incentives stating, “Will customer take the same amount
10 of action for half the money?” (Exhibit MEIU-2.9), a question that Consumers does not
11 grapple with in its own discussion of its proposal.

12
13 **Q. Do you agree with Consumers’ proposal to reduce the PTR program credit value?**

14 A. No. I believe that the proposed bill credit value is unjustified. Consumers’ states that “with
15 this lower [customer demand savings capability] value being nearly half the previous value
16 for PTR, the Company determined that the credit offered to these customers should also be
17 halved.”³⁰ Consumers attempts to defend this proposal using information provided by
18 Cadmus, which states that “lowering the incentive per kWh saved can achieve up to 50%
19 in cost savings, *assuming consumer behavior stays the same*” (emphasis added) (Exhibit
20 MEIU-2.8). It is critical to note that in making this proposal, the Company does not take
21 into account whether consumer behavior will stay the same or change at the reduced
22 incentive level. It is telling that even Cadmus questions this assumption, stating on a slide

³⁰ Gast Direct, p. 14.

1 in the 2025 Presentation: “Will customers take the same amount of action for half the
2 money?” (Exhibit MEIU-2.9). In a discovery response (Exhibit MEIU-2.13) regarding how
3 changing the incentive may change customer behavior, Consumers specifically states that
4 it “identified the potential risk but did not have any data to support how changing the
5 incentive amount would affect customer behavior.”

6
7 I contend that it is reasonable to assume that if the PTR bill credit (i.e. the customer
8 incentive) is reduced by 50%, then consumer behavior will likely change because the
9 consumer is less incentivized to adjust their behavior compared to the previous
10 incentivization. Without getting additional data on how reducing the PTR program bill
11 credit will impact customer behavior, it is premature to propose such a drastic change in
12 the instant rate case.

13
14 **Q. Do you agree with Consumers’ considerations regarding cost-effectiveness of the DPP**
15 **program?**

16 A. No. Cost-effectiveness is always important when considering the successfulness of any
17 program, and Consumers has stated that its proposals to the DPP program are intended to
18 “help improve cost-effectiveness.” (Exhibit MEIU-2.8). However, as described previously,
19 Consumers has failed to prove that the DPP program under the current construct is not
20 already cost-effective. The results of the conducted benefit-cost analysis show that the DPP
21 program is already a cost-effective program that exhibits net benefits and has the lowest
22 levelized cost per MW when compared to all other DR programs that Consumers oversees.
23 Therefore, the DPP program should not be changed based on the unsubstantiated argument

1 that the DPP program needs to improve its cost-effectiveness.³¹ Doing so may in fact have
2 the effect of undermining or even sabotaging an already cost-effective program by making
3 the perfect the enemy of the good.

4
5 Additionally, it is important to note that this program has a relatively low cost and bill
6 impact for residential customers, with a proposed annual surcharge of \$0.002009 per kWh
7 applied to all residential customers for all of the residential DR programs, costs which,
8 again, are made up for elsewhere through this cost-effective program.

9
10 **Q. Do you agree with Consumers' proposal to discontinue the PTR program customer**
11 **enrollment incentives?**

12 A. No. In his direct testimony, Company witness Gast states that,

13 Given the change in strategy to use PTR as a gateway DR program, the
14 Company has made significant changes to reduce expenses for the program
15 to improve cost-effectiveness. The Company is: (1) working on the
16 discontinuation of customer enrollment incentives, and (2) focusing
17 primarily on low to no cost marketing channels including the Consumers
18 Energy website during the time of move-in.³²

19
20 I disagree with the Company's proposal to discontinue the customer enrollment incentives
21 for the PTR program in order to improve program cost-effectiveness. There is no merit in
22 discontinuing the use of customer enrollment incentives and shifting towards low to no
23 cost marketing channels, especially considering that this program already appears to be
24 cost-effective as established in the prior sections of my testimony. Furthermore, I contend

³¹ I also contend that, given the DPP Program's focus on low-income and "entry-level" DR participants, cost-effectiveness may be of less importance for this program. An opportunity under this program and a non-quantifiable benefit is to introduce customers to other DR programs and make customers knowledgeable of DR.

³² Gast Direct, p. 15.

1 that the existing customer enrollment incentives and marketing efforts are likely the exact
2 actions that allowed the PTR program to evolve into a “gateway DR program” over time.

3
4 **IV. RECOMMENDATIONS AND CONCLUSIONS**

5
6 **Q. Please summarize your recommendations for the instant rate case.**

7 **A.** I recommend that the Commission:

- 8 • Reject Consumers’ proposal to reduce the per customer demand savings values for
9 the CPP and PTR programs until the Company conducts an updated analysis and
10 review of the CPP and PTR programs expected performance under current planning
11 conditions.
- 12 • Reject Consumers’ proposal to reduce the PTR program bill credit value on the
13 grounds that Consumers has not conducted an analysis or obtained information on
14 how changing the incentive amount would affect customer behavior.
- 15 • Reject Consumers’ proposal to discontinue PTR program customer enrollment
16 incentives.

17
18 **Q. Does this conclude your testimony?**

19 **A.** Yes.

1 MR. OOMS: Thank you, Your Honor. And finally,
2 on behalf of MEIU, I would move for the admission or
3 excuse me, the binding in of the direct and rebuttal
4 testimony of witness John Albers. His direct testimony
5 consists of a cover page, a table of contents, and 10
6 pages of questions and answers. His rebuttal testimony
7 consists of a cover page, a table of contents, and nine
8 pages of questions and answers. Also, move for the
9 admission of the exhibits he sponsored, which are exhibits
10 MEIU-3.1 through exhibit MEIU-3.10.

11 JUDGE THOITS: Are there any objections to the
12 admission of this testimony or these exhibits?

13 Hearing none. The direct and rebuttal testimony
14 of John Albers is bound into the record, and exhibits
15 MEIU-3.1 through MEIU-3.10 are admitted.

16
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25

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 generation and distribution of)
electricity and for other relief.)

Case No. U-21870

DIRECT TESTIMONY OF JOHN D. ALBERS
ON BEHALF OF
THE MICHIGAN ENERGY INNOVATION BUSINESS COUNCIL,
INSTITUTE FOR ENERGY INNOVATION,
AND
ADVANCED ENERGY UNITED

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1 **I. INTRODUCTION AND QUALIFICATIONS**

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

3 A. My name is John D. Albers. My business address is 1801 Pennsylvania Avenue NW, Suite
4 410, Washington, DC 20006.

5
6 **Q. By whom are you employed and in what capacity?**

7 A. Since October of 2023, I have been employed by Advanced Energy United, Inc. (“United”)
8 as the Director overseeing regulatory policy for the central states where United is active.
9 This includes Illinois, Michigan, Indiana, and Wisconsin.

10

11 **Q. On whose behalf are you testifying?**

12 A. I am testifying on behalf of the Michigan Energy Innovation Business Council (“Michigan
13 EIBC”), the Institute for Energy Innovation, and United, collectively referred to as
14 “MEIU.”

15

16 **Q. Did you prepare or direct the preparation of this testimony?**

17 A. Yes.

18

19 **Q. Please describe your background.**

20 A. I earned a Bachelor of Arts in Political Science from Illinois State University in 1994 and
21 Juris Doctorate from the University of Illinois College of Law in 1997. I have been
22 admitted to practice law in the State of Illinois since 1997.

23

1 In February of 1998 I joined the Illinois Commerce Commission (“ICC”) as an
2 Administrative Law Judge and presided over nearly every type of public utility matter that
3 came before the ICC until I left in 2015. Issues I gained experience with include, but are
4 not limited to, rate design, cost recovery, interconnection, metering, energy procurement,
5 renewable energy credit (“REC”) procurement, and distributed generation (“DG”). Over
6 the years, I took on increasing responsibility, including overseeing informal agency
7 workshops, testifying on behalf of the agency in legislative hearings, and recommending
8 agency positions on proposed legislation.

9
10 After leaving the ICC, I practiced law until early 2022, representing and advising
11 individuals, small and large businesses, small utilities, and state and national not-for-profit
12 organizations on various matters pertaining to renewable energy, infrastructure siting,
13 utilities, DG, tariffs, and other issues. I frequently represented clients in matters before the
14 ICC. During this period, I also worked part-time as a contract real estate developer for IPS
15 Solar securing leases and permits for community solar projects in Illinois.

16
17 From March of 2022 until August of 2023, I oversaw SunPower Corporation’s policy and
18 strategy efforts in the Midwest. SunPower was a national seller of residential rooftop solar
19 energy systems. In this role I educated state utility regulatory commissioners and legislators
20 and advocated for policies that would improve and expand the market for residential solar
21 installations.

22

1 In my role at United, I advocate for policies at state utility regulatory commissions that
2 enable greater deployment of advanced energy technologies with the ultimate goal of
3 powering our economy with clean energy. This requires understanding member interests
4 and priorities. Recent areas of interest include siting larger distributed energy resources
5 (“DERs”), interconnection of both large and small DERs, as well as electric vehicle (“EV”) charging stations, aggregation of DERs as part of virtual power plants (“VPP”), large load
6 tariffs, decarbonization of the natural gas distribution system, and better planning and
7 coordination by and between electric and gas utilities. My work experience and education
8 are set forth in detail in my resume, attached as Exhibit MEIU-3.1.
9

10
11 **Q. Are you representing MEIU as legal counsel as well?**

12 A. No. I am not representing MEIU as legal counsel and am not testifying as an attorney.
13 MEIU will present its legal arguments in its briefs.
14

15 **Q. Have you previously testified before the Michigan Public Service Commission**
16 **(“Commission”)?**

17 A. Yes, on four occasions. I previously offered testimony in Case No. U-21585, concerning
18 Consumers Energy Company’s (“Consumers”) application to increase its electric rates.
19 My testimony addressed Consumers’ proposed DER management system (“DERMS”) and
20 the need to maintain a proper inventory of equipment with long-acquisition lead times. I
21 also offered testimony in Case No. U-21375, concerning DTE Electric Company’s
22 (“DTE”) voluntary green pricing program, and specifically whether the Commission
23 should require DTE to purchase RECs from customers with DG systems. In addition, I

1 offered testimony in Case No. U-21859 regarding the tariff terms and conditions governing
2 service to large load customers in Consumers’ territory. Most recently, I offered testimony
3 in a DTE electric rate case, Case No. U-21860, addressing DTE’s demand response
4 procurement efforts as well as DERMS and VPP tariff development.

5
6 **Q. Have you previously testified before other state public utility commissions?**

7 A. Yes. I offered testimony in 2022 on behalf of the Joint Solar Parties in ICC Docket No. 22-
8 0036 regarding net metering. I also testified in 2024 on behalf of United in ICC Docket
9 No. 22-0486 pertaining to data access, a proposed spare transformer program, and
10 DERMS. At the Indiana Utility Regulatory Commission, I offered testimony in 2024 on
11 behalf of United in an investigation (Cause No. 46043) concerning whether DER
12 aggregators are public utilities under Indiana law.

13
14 **Q. Are you offering any exhibits with your testimony?**

15 A. Yes, I am offering the following exhibits:

- 16 • Exhibit MEIU-3.1: Résumé of John Albers
- 17 • Exhibit MEIU-3.2: Discovery response U21870-MEIU-CE-0394

18
19 **Q. What is the purpose of your testimony?**

20 A. The purpose of my direct testimony is to respond to the testimony of Consumers witness
21 Michael Kelly regarding the acquisition of hardware for which there is a long wait to
22 receive the hardware after ordering.¹

¹ Direct Testimony of Michael Kelly on behalf of Consumers Energy Company, Case No. U-21870 (“Kelly Direct”), pp. 185–188.

1
2 **II. EQUIPMENT INVENTORY**

3 **Q. What is the concern with hardware with a long acquisition lead time?**

4 A. As Michigan, and much of the nation, experiences a growth in DER deployment,
5 transportation electrification, and electricity demand, it is important that electric utilities
6 have the means to accommodate such growth. This includes utilities having the necessary
7 hardware they are responsible for providing to accomplish interconnections with the
8 electric grid. In its prior electric rate case, Case No. U-21585, several Consumers witnesses
9 expressed concern about the long lead time associated with obtaining transformers.² I
10 noted in my testimony in that case that such long lead times for obtaining transformers was
11 consistent with my experience as well.³ Because of long lead times associated with
12 obtaining critical equipment necessary for accomplishing interconnections, deployment of
13 new DER, EV charging stations, and generation resources can be delayed. Such delays not
14 only impede the goals of utilities and developers but can hamper Michigan's ability to meet
15 its statutory clean energy standard of 80% between 2035 and 2039 and 100% by 2040.⁴
16 The initial 80% standard is only 10 years away.

17

² In discussing delays in the development of solar projects, Company witness Thomas Clark describes as a challenge longer acquisition lead time for key components, such as transformers. (Direct Testimony of Thomas P. Clark on behalf of Consumers Energy Company, Case No. U- 21585, p. 28.) Company witness Keith Kurdziel provides greater detail about the lead times for transformers, indicating that it can take two years to obtain one. (Direct Testimony of Keith M. Kurdziel on behalf of Consumers Energy Company, Case No. U- 21585, p. 49.) Company witness Jeffrey Myrom confirms this timeframe for ordering transformers. (Direct Testimony of Jeffrey A. Myron on behalf of Consumers Energy Company, Case No. U- 21585, p. 51.)

³ Direct Testimony of John D. Albers on behalf of MEIU, Case No. U-21585 ("Albers U-21585 Direct"), p. 30.

⁴ Public Act 235 of 2023.

1 **Q. Can anything be done to address this concern?**

2 A. Yes. To mitigate this risk, I proposed in Consumers' last rate case, Case No. U-21585, that
3 the Commission direct Consumers to identify hardware commonly associated with
4 interconnecting advanced energy technologies, like DERs and EV charging facilities, that
5 has long acquisition lead times. After having done so, to the extent that Consumers does
6 not maintain an adequate inventory of transformers and other such equipment for the timely
7 development and installation of advanced energy technologies, I recommended that the
8 Commission direct Consumers to develop and propose in its next general electric rate case
9 a system for maintaining an inventory of such equipment. I pointed out that reviewing this
10 information will help the Commission and stakeholders evaluate the merits of maintaining
11 such an inventory.⁵

12

13 **Q. How did the Commission respond to your recommendation?**

14 A. The Commission found merit in my recommendation. In its March 21, 2025 Order in Case
15 No. U-21585, when discussing Consumers' purchase of long lead time transformers, the
16 Commission stated:

17 That said, the Commission does, however, agree with the ALJ and MEIU
18 about the reasonableness of having the company provide greater
19 transparency around these purchases. The Commission thus finds it
20 appropriate for Consumers, in its next electric rate case, to: "(1) identify
21 equipment generally needed for DER and EV interconnections, such as
22 transformers, that currently have a long lead time for procurement, and (2)
23 propose a plan for maintaining an adequate inventory of that equipment to
24 support future development." PFD, p. 64; *see also*, MEIU's initial brief,
25 pp. 32-33.⁶

26

⁵ Albers U-21585 Direct, p. 31.

⁶ March 21, 2025 Order in Case No. U-21585, p. 42.

1 **Q. Did Consumers comply with the Commission’s direction in this regard?**

2 A. Possibly. Consumers witness Kelly addressed the Commission’s direction to identify
3 equipment generally needed for DER and EV interconnections that currently have a long
4 lead time for procurement. Figure 53 in his testimony lists several categories of equipment
5 and for each category identifies “a) whether or not the Company has a long-term demand
6 plan forecast of likely needs; b) whether or not the Company has identified multiple
7 suppliers to provide redundancy; and c) whether or not the Company has a long-term
8 contract of at least three to five years’ duration with at least one supplier.”⁷ Witness Kelly
9 adds that by the end of the year Consumers will have long-term contracts with a supplier
10 for each category of equipment. He asserts that “making a demand plan, securing multiple
11 suppliers, and establishing long-term contracts” represents Consumers’ three-pronged
12 approach to its supply chain strategy.⁸

13

14 In my opinion, Figure 53 in witness Kelly’s direct testimony satisfies the Commission’s
15 direction to “identify equipment generally needed for DER and EV interconnections, such
16 as transformers, that currently have a long lead time for procurement.” It is less clear
17 whether the remainder of what witness Kelly describes satisfies the direction to “propose
18 a plan for maintaining an adequate inventory of that equipment to support future
19 development.” It is possible that the “demand plan forecast of likely needs” that witness
20 Kelly references satisfies the requirement for “a plan for maintaining an adequate
21 inventory,” but witness Kelly has not provided the actual plan for any of the equipment
22 listed. Because Figure 53 simply indicates that a demand plan exists, but does not provide

⁷ Kelly Direct, p. 186.

⁸ *Id.*, p. 187.

1 any such plan, I cannot say with certainty that Consumers “propose[d] a plan for
2 maintaining an adequate inventory of that equipment to support future development.”
3 Ostensibly, contracting with suppliers of equipment could be a sufficient plan for ensuring
4 an adequate supply, but without knowing the demand plan or forecast witness Kelly
5 references, this is difficult to determine.
6

7 **Q. Has Consumers provided any other information to ensure an adequate supply of**
8 **equipment with long acquisition lead times?**

9 A. Yes. Exhibit MEIU-3.2 consists of Consumers’ response to a discovery request seeking
10 additional information about the equipment listed in Figure 53, including any additional
11 aspects of the plan for maintaining an adequate inventory of the equipment. The
12 information provided identifies the inventory in stock for each category of equipment at
13 the end of each quarter for the years 2022, 2023, and 2024. Consumers also provided the
14 number of items used to interconnect DERs and EV charging infrastructure projects not
15 initiated by the company each of the same three calendar years. The information includes
16 the acquisition lead time associated with each category of equipment the last time
17 Consumers ordered the equipment. Consumers witness Kelly provided the response and
18 stated that Consumers does not have any additional aspects of its plan to share beyond
19 those stated in his direct testimony.
20

1 **Q. Does the additional information in Exhibit MEIU-3.2 persuade you to conclude that**
2 **Consumers maintains an adequate inventory of hardware commonly used to**
3 **interconnect DERs and EV charging stations?**

4 A. While there are some discrepancies in the acquisition lead times listed,⁹ based on the
5 quantity of items Consumers reports using to accommodate new DERs and EV charging
6 infrastructure projects over the past three calendar years, it appears that Consumers
7 maintains a sufficient inventory of the listed equipment. This holds true even considering
8 the overall increases in equipment used to accommodate DER and EV projects over the
9 three-year period spanning 2022 through 2024.

10
11 **Q. Do you have any remaining concerns related to Consumers' acquisition and inventory**
12 **of equipment with long lead times?**

13 A. Ideally, we would also know what the demand plan for each category of equipment entails,
14 as I described above. Given the quantity of equipment Consumers used to facilitate DER
15 and EV projects over the past three years and the inventory Consumers maintained over
16 the same period, however, I am less concerned about knowing the details of the demand
17 plans. To ensure greater certainty for developers, I recommend that the Commission
18 require Consumers to make its inventory of equipment with long acquisition lead times
19 available to DER and EV projects initiated by third parties on the same basis that such
20 equipment is available to the utility for projects that it initiates.

⁹ For example, on page 2 of Attachment 1 to the discovery response, Consumers lists the lead time for overhead cable ordered for DER projects on July 1, 2024, as 52 weeks, while it lists the lead time for overhead cable ordered for EV projects on the same day as 39 weeks. Another example relates to reclosers; DER reclosers ordered on June 6, 2024, reflects a lead time of 48 weeks, while EV reclosers ordered on July 16, 2024, reflect a lead time of 39 weeks. In the case of the reclosers, it is possible those are two separate orders, perhaps even from different suppliers, which could explain the different order dates and lead times. It is simply unclear since most of the other equipment orders reflect the same dates and lead times for DER and EV projects.

1

2 **III. CONCLUSIONS AND RECOMMENDATIONS**3 **Q. Please summarize your conclusions and recommendations to the Commission.**

4 A. I recommend that the Commission direct Consumers to make its inventory of equipment
5 with long acquisition lead times available to DER and EV projects initiated by third parties
6 on the same basis that such equipment is available to Consumers for projects that it initiates.

7

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

9 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 generation and distribution of)
electricity and for other relief.)

Case No. U-21870

REBUTTAL TESTIMONY OF JOHN D. ALBERS
ON BEHALF OF
THE MICHIGAN ENERGY INNOVATION BUSINESS COUNCIL,
INSTITUTE FOR ENERGY INNOVATION,
AND
ADVANCED ENERGY UNITED

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1 **I. INTRODUCTION**

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

3 A. My name is John D. Albers. My business address is 1801 Pennsylvania Avenue NW, Suite
4 410 Washington, DC 20006.

5
6 **Q. By whom are you employed and in what capacity?**

7 A. I am employed by Advanced Energy United, Inc. (“United”) as the regulatory policy
8 director for the central region states where United engages in regulatory policy advocacy
9 efforts.

10

11 **Q. On whose behalf are you testifying?**

12 A. I am testifying on behalf of the Michigan Energy Innovation Business Council, the Institute
13 for Energy Innovation, and United, collectively referred to as “MEIU.”

14

15 **Q. Are you the same John D. Albers who previously provided direct testimony in this**
16 **proceeding on behalf of MEIU?**

17 A. Yes.

18

19 **Q. Did you prepare or direct the preparation of this rebuttal testimony?**

20 A. Yes.

21

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

23 A. Yes, I am offering the following exhibits:

- 1 • Exhibit MEIU-3.3: JNGO Ex. 3.01, Illinois Commerce Commission (“ICC”)
- 2 Docket No. 22-0486, 23-0055, and 24-0181 (Consolidated);
- 3 • Exhibit MEIU-3.4: U21870-GLREA-CE-0275;
- 4 • Exhibit MEIU-3.5: U21870-GLREA-CE-0276;
- 5 • Exhibit MEIU-3.6: U21870-GLREA-CE-0277;
- 6 • Exhibit MEIU-3.7: U21870-GLREA-CE-0279;
- 7 • Exhibit MEIU-3.8: U21870-GLREA-CE-0280;
- 8 • Exhibit MEIU-3.9: U21870-GLREA-CE-0297; and
- 9 • Exhibit MEIU-3.10: U21870-GLREA-CE-0298;

10

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

12 A. The purpose of my rebuttal testimony is to respond to the direct testimony of Clean Energy
13 Organizations (“CEO”) witness William Kenworthy and Great Lakes Renewable Energy
14 Association (“GLREA”) witness Richard Boehnke concerning virtual power plants
15 (“VPP”). I generally support witness Kenworthy and witness Boehnke’s recommendations
16 related to VPPs but have an additional recommendation that I believe will improve the
17 likelihood that Consumers Energy Company (“Consumers”) will be able to offer a
18 successful VPP program. I also identify a resource available to Consumers to assist with
19 efforts to develop a successful VPP program.

20

1 **II. VPP RECOMMENDATIONS**

2 **Q. What does witness Kenworthy recommend regarding VPPs?**

3 A. Briefly, witness Kenworthy describes in his direct testimony the opportunities and benefits
4 available through VPPs and encourages Consumers to develop a strong VPP program in
5 conjunction with a distributed energy resources management system (“DERMS”).¹ He
6 also recommends specific requirements that the Michigan Public Service Commission
7 (“Commission”) should impose upon Consumers to take advantage of VPPs within its
8 service territory.²

10 **Q. What does witness Boehnke recommend regarding VPPs?**

11 A. Briefly, witness Boehnke offers through his direct testimony several examples of
12 successful VPP programs in other jurisdictions and provides compelling arguments for the
13 deployment of a VPP program by Consumers.³ Mr. Boehnke further recommends near-
14 term and long-term actions the Commission can take to ensure successful implementation
15 of a VPP program.⁴

17 **Q. Do you agree with witness Kenworthy and witness Boehnke?**

18 A. Generally, yes, but I recommend additional considerations be taken into account in the
19 development of any VPP tariff by Consumers.

¹ Direct Testimony of William D. Kenworthy on behalf of CEO, Case No. U-21870 (“Kenworthy Direct”), pp. 9–17.

² *Id.*, p. 17.

³ Direct Testimony of Richard Boehnke on behalf of GLREA, Case No. U-21870 (“Boehnke Direct”), pp. 12–16, 22–33, 47.

⁴ *Id.*, pp. 60–63.

1 First, Consumers already has demand response (“DR”) programs in place covering
2 residential, commercial, and industrial customers. For instance, Consumers runs a Smart
3 Thermostat Program. I encourage the Commission to direct that any new VPP program be
4 developed with existing programs in mind and that Consumers find ways to leverage and
5 incorporate existing investments and practices that have allowed it to scale its DR programs
6 to date. This is especially important given that some Consumers customers in any future
7 VPP program are likely to already be participating in an existing DR program with other
8 distributed energy resources (“DER”). To be clear, I am not suggesting that Consumers’
9 existing DR programs should end; rather, I am suggesting that Consumers appropriately
10 modify and fold its existing DR programs into a VPP program so that all such resources
11 can be operated in a coordinated manner to bring maximum benefit to ratepayers and the
12 electric grid.

13
14 Second, data sharing among the utility, customers, and DER aggregators plays a key role
15 in any VPP program. For a VPP program to be successful, shared data must be timely,
16 reliable, and sufficiently detailed. If the Commission directs Consumers to develop a VPP
17 tariff as the CEO and GLREA witnesses propose, I recommend that the Commission
18 specifically direct Consumers to work with interested stakeholders to develop a robust data
19 sharing platform. Illinois electric utility Commonwealth Edison Company (“ComEd”) is
20 currently involved in such an effort pursuant to a memorandum of understanding (“MOU”)
21 it entered into with certain parties in its recent proceeding concerning its multi-year
22 integrated grid plan, ICC Docket Nos. 22-0486, 23-0055, and 24-0181 (Consolidated). To
23 provide the Commission with an idea of the data sharing platform ComEd agreed to

1 develop, I have attached the MOU to my rebuttal as Exhibit MEIU-3.3.⁵ The work of
2 developing a strong data sharing platform can also be a part of the DERMS development
3 process the Commission directed Consumers to conduct in its last general electric rate case,
4 Case No. U-21585.⁶

5
6 Third, given the interest in VPPs from multiple participants in this proceeding, the general
7 interest in VPPs in the electric industry that I am aware of through my work, and my
8 impression from Consumers' response to several discovery questions⁷ that it has given little
9 thought to developing a comprehensive and coordinated VPP program, I recommend, in
10 addition to the steps witness Kenworthy and witness Boehnke propose that Consumers
11 follow, that the Commission also require Consumers to engage interested stakeholders
12 early and often in its VPP program tariff development process. More specifically, I
13 recommend that the Commission explicitly require Consumers to publicize and hold
14 multiple virtual meetings open to interested stakeholders to solicit input on program design
15 and share preliminary tariff language with stakeholders for further input. The Commission
16 should direct Consumers to provide opportunities for written feedback as well. I note that
17 the ability to attend stakeholder meetings virtually is important since many of those
18 interested are likely not based in the immediate area of Consumers' service territory.
19 Providing for robust stakeholder input will enable Consumers and entities experienced with
20 VPPs to exchange their knowledge and expertise, as well as create an opportunity for this

⁵ Please note that while the MOU is labeled "PRIVILEGED AND CONFIDENTIAL – SETTLEMENT COMMUNICATION," it was entered into the record of the ICC proceeding as a public document and is available from the ICC's public website at: <https://www.icc.illinois.gov/docket/P2022-0486/documents/350981/files/613798.pdf>.

⁶ March 21, 2025 Order in Case No. U-21585, Filing No. U-21585-0396, pp. 117-118.

⁷ See Exhibits MEIU-3.4 through 3.10.

1 information to be shared with the Commission. I further recommend that the Commission
2 direct Consumers to assess best practices of successful VPP programs, such as
3 ConnectedSolutions, since there is no need to reinvent a VPP program when other utilities
4 have already deployed such programs.

5
6 My recommendation to solicit stakeholder input and assess best practices is consistent with
7 the aforementioned findings in the Commission’s Order in Case No. U-21585. As alluded
8 to above, one of the issues in that proceeding related to Consumers’ plan for a DERMS. In
9 finding that Consumers failed to fully explain and justify its DERMS proposal, the
10 Commission directed Consumers to develop a strong business case before seeking cost
11 recovery in a future rate case. The Commission provided guidance on how to do so, which
12 included the following:

13 Therefore, should Consumers seek recovery for a DERMS in a future
14 electric rate case, it is incumbent on the company to provide a business case
15 for the program, including a comprehensive [benefit-cost analysis], that
16 sufficiently identifies and justifies the program’s costs and benefits to
17 customers. When developing such a business case, Consumers should look
18 at other states’ best practices for examples of plans that can be readily
19 implemented with regard to valuing the benefits of DERs and that are more
20 actionable than the company’s current proposal to hire a consultant to
21 contract for the development of a strategy and business case. See, e.g.,
22 Exhibit CEO-5, pp. 13-18. The Commission notes that development of such
23 a business case should provide opportunities for interested persons to
24 provide robust feedback and input into the business case and must include
25 an analysis of the use of VPPs. The Commission encourages the company
26 to initiate a workgroup with interested persons and to develop more pilots
27 or other actionable proposals to develop and further evolve the company’s
28 initial proposal.⁸

29 It is clear from this Order that the Commission is interested in incorporating stakeholder
30 feedback and identifying best practices during program development related to DERMS

⁸ March 21, 2025 Order in Case No. U-21585, Filing No. U-21585-0396, pp. 117-118.

1 and there is no reason to eschew the advantages of such outreach in the case of a future
2 VPP program.

3
4 **Q. You indicated earlier that there is an additional resource available to Consumers that**
5 **could be helpful in the development of a VPP program. Can you share more about**
6 **that?**

7 A. Yes. I am referring to the CHARGED Initiative (“CHARGED”).⁹ CHARGED stems from
8 a collaboration among United, RMI, and GridLab.¹⁰ These three entities formed
9 CHARGED to ensure that the nation’s electricity distribution system is ready to support
10 the electrification of the transportation and building sectors. One way in which
11 CHARGED works toward this goal is to directly assist utilities to develop new programs
12 and tariffs without additional cost to the utility. CHARGED is knowledgeable about VPP
13 programs and is currently assisting Illinois electric and gas utility Ameren Illinois
14 Company (“Ameren”) develop a VPP tariff. I have attended the workshops held thus far
15 in that effort and have found them informative and helpful. Multiple attendees have
16 engaged in meaningful discussions to assist Ameren in its tariff design. I encourage
17 Consumers to consider also taking advantage of this free resource.

18
19 In addition, I note that ComEd engaged CHARGED to assist with its development of a
20 DERMS and flexible interconnection process. ComEd filed the preliminary results of that
21 work in ICC Docket Nos. 22-0486, 23-0055, and 24-0181 (Cons.) in the form of a report

⁹ <https://gridlab.org/chargedinitiative/>

¹⁰ Although I am employed at United, I am not directly involved with CHARGED.

1 earlier this year.¹¹ I mention ComEd's experience with CHARGED in the context of
2 DERMS because witness Kenworthy also discusses Consumers' DERMS development in
3 his direct testimony.¹² CHARGED is well situated to assist with these and other aspects
4 of Consumers' DERMS development.

5
6 **III. CONCLUSION AND RECOMMENDATIONS**

7 **Q. Please summarize your conclusions and recommendations to the Commission.**

8 A. In addition to the recommendations in my direct testimony, I recommend that the
9 Commission:

- 10 1. Require Consumers to incorporate its existing DR programs into any VPP program
11 it develops;
- 12 2. Require Consumers to meaningfully engage interested stakeholders and develop a
13 robust data sharing platform;
- 14 3. Require Consumers to publicize and hold multiple virtual meetings open to
15 interested stakeholders to meaningfully engage stakeholders, solicit input on VPP
16 program design, and share preliminary tariff language with stakeholders for further
17 input;
- 18 4. Require Consumers to provide opportunities for written feedback in its VPP
19 development process;
- 20 5. Require Consumers to identify best practices in its VPP development process; and

¹¹ Commonwealth Edison Company and Joint Non-Governmental Organizations' Update on Efforts Around Offering of DERMS and Flexible Interconnection, July 18, 2025, Illinois Commerce Commission Docket Nos. 22-0486, 23-0055, and 24-0181 (Cons.), <https://www.icc.illinois.gov/docket/P2022-0486/documents/368172>

¹² Kenworthy Direct, pp. 3-5.

1 6. Encourage Consumers to avail itself of available resources in the development of
2 its DERMS plans and VPP tariff, including the CHARGED Initiative.

3

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

5 **A. Yes.**

1 MR. OOMS: Thank you, Your Honor. That
2 concludes MEIU's evidentiary presentation for this case.

3 JUDGE THOITS: Thank you. Mr. Sonnveldt, I
4 think that leaves you.

5 MR. SONNVELDT: I think so, Your Honor, and I'm
6 prepared to move forward, but if I recall though, I would
7 point out, I think at the end of presenting his testimony
8 for bind in, Mr. Templeton re -- explained that he would
9 come back with some hearing room exhibits for bind in, and
10 I don't want to skip that, if that is -- if my
11 recollection is correct.

12 JUDGE THOITS: All right, I appreciate that. I
13 don't want to skip it either. Let's see.

14 MR. SONNEVELDT: I don't see him on, though.

15 JUDGE THOITS: Right. But why don't we do this?
16 Why don't we proceed with you and Staff's witnesses, and
17 then we will see if he has joined us subsequently, and if
18 not, we'll deal with that then.

19 MR. SONNEVELDT: Sounds good. Thank you, Your
20 Honor.

21 JUDGE THOITS: Thank you.

22 MR. SONNVELDT: Are you ready?

23 JUDGE THOITS: Yes, sir.

24 MR. SONNVELDT: At this time, Staff would like

1 to bind in the direct and rebuttal testimony of Allan D.
2 Freeman. His direct testimony consists of a cover sheet
3 and seven pages of questions and answers. His rebuttal
4 testimony consists of a cover page and two pages of
5 questions and answers. He has no exhibits.

6 JUDGE THOITS: Are there any objections to the
7 admission of this testimony?

8 Hearing none. The direct and rebuttal testimony
9 of Allan Freeman is bound into the record.

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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	)	Case No. U-21870
the generation and distribution of	)	
electricity and for other relief.	)	
	)	

QUALIFICATIONS AND DIRECT TESTIMONY OF
ALLAN D. FREEMAN
MICHIGAN PUBLIC SERVICE COMMISSION

September 30, 2025

QUALIFICATIONS OF ALLAN D. FREEMAN
CASE NUMBER U-21870
PART I

1 Q. Please state your full name and business address for the record.

2 A. My name is Allan David Freeman, and my business address is 7109 W. Saginaw Hwy.,
3 Lansing, MI 48917.

4 Q. By whom are you employed and in what capacity?

5 A. I am employed by the Michigan Public Service Commission (MPSC or Commission) as
6 an Assistant to the Division Director in the Energy Resources Division.

7 Q. Please describe your educational background.

8 A. I hold three degrees. In 2000, I earned a Juris Doctor and a Masters of Public
9 Administration, both from the University of Pittsburgh. I earned a Bachelor of Arts in
10 International Relations from Michigan State University in 1996.

11 Q. What is your professional background?

12 A. In 2009, I began working for the MPSC in the Energy Markets section. My
13 responsibilities included representing Michigan and advocating policy objectives during
14 meetings of the Organization of MISO States (OMS) and the Organization of
15 Pennsylvania-New Jersey-Maryland Interconnection (PJM) States, Inc. I coordinated
16 regulatory oversight and policy formation among the states. Additionally, I collaborated
17 to perform analysis and evaluation on the elements of existing and future market designs.
18 I served as co-chair of OMS's Market and Tariff workgroup. I attended the Eastern
19 Interconnection States' Planning Council, Federal Energy Regulatory Commission
20 (FERC), Midcontinent Independent System Operator (MISO), and PJM Interconnection
21 stakeholder work groups and committee meetings. Lastly, I drafted speeches for MPSC
22 Commissioners (Commissioners).

QUALIFICATIONS OF ALLAN D. FREEMAN
CASE NUMBER U-21870
PART I

1 In 2015, I became an Executive Policy Advisor in the Research Section of the
2 Strategic Operations Division. In this role, I advised the Commissioners on policy and
3 technical matters pertaining to the Commission's regulatory and policy-making
4 responsibilities across all regulated sectors. I assisted the Commissioners during
5 deliberations on decisions in general rate cases, certificate of need proceedings, energy
6 law implementation, and electricity and natural gas fuel cost cases. Additionally, I
7 negotiated decisions on behalf of the Commissioners. I conducted research on emerging
8 jurisdictional, structural, and technical issues in the utility industries. I represented the
9 Commissioners in various capacities and functions involving industry and the public.

10 In 2020, I became the Assistant to the Division Director in the Energy
11 Resources Division. This division is responsible for implementation of the State's Clean
12 & Renewable Energy and Energy Waste Reduction Act, evaluating certificate of
13 necessity and integrated resource plan filings, reviewing Smart Grid utility investments,
14 administration of Michigan's gas and electric customer choice programs, and electric
15 resource adequacy and modeling. I assist the Energy Resources Division Director in
16 program planning, policy and procedures development, and research. I review testimony
17 for contested case proceedings. I represent the Director in meetings, settlement
18 conferences, and task forces. I serve as the MPSC Staff (Staff) lead for our internal
19 electric vehicles team. Lastly, I co-chaired the Commission's Diversity, Equity, and
20 Inclusion initiative.

21 Q. Have you received any work-related training since your employment with the MPSC?

22 A. Yes, I have attended several programs hosted by the Institute of Public Utilities (IPU) at
23 Michigan State University: the Michigan Forum on Economics and Regulatory Policy,

QUALIFICATIONS OF ALLAN D. FREEMAN
CASE NUMBER U-21870
PART I

1 the Annual Regulatory Studies Program, IPU's Grid and Rate Schools, the National
2 Regulatory Research Institute, and several Advanced Regulatory Studies Program
3 sessions.

4 Q. Have you previously filed testimony before the Commission?

5 A. Yes. I have filed testimony in the following cases: U-20836, DTE Electric's 2022 rate
6 case; U-21224, Consumers Energy Electric's 2022 rate case; U-21279, DTE Electric's
7 2023 rate case; U-21389, Consumers Energy Electric's 2023 rate case; U-21401, Indiana
8 Michigan Power Company's 2023 rate case; U-21534, DTE Electric's 2024 rate case;
9 Consumers Energy Electric's 2024 rate case U-21585; and DTE Electric's 2025 rate case,
10 U-21860.

11 Q. Have you worked to analyze any cases filed before the Commission?

12 A. Yes, in my role as Executive Policy Advisor, I assisted in the deliberations on many
13 different types of cases. I was intimately involved in both electric and gas rate cases,
14 Certificate of Need proceedings, Integrated Resource Plan (IRP) cases, Securitization
15 proceedings, reliability dockets, renewable energy cases, and the MI PowerGrid
16 stakeholder initiatives.

**DIRECT TESTIMONY OF ALLAN D. FREEMAN
CASE NUMBER U-21870
PART II**

1 Q. What is the purpose of your testimony?

2 A. The purpose of my testimony is to present MPSC Staff's analysis of Consumers Energy
3 Electric Company's (Consumers or the Company) electric vehicle (EV) rate case
4 proposals.

5 Q. Are you sponsoring any exhibits?

6 A. No.

7 Q. What is the purpose of the Company's EV testimony?

8 A. Company witness Jeffrey Myrom outlines the Company's execution of its Transportation
9 Electrification Plan (TEP) and proposes enhancements to improve the customer
10 experience.

11 Q. What is the TEP's purpose?

12 A. The TEP focuses on the Company's long-term strategies to optimize EV charging load so
13 that it benefits all customers. Additionally, the TEP identifies the investments, incentives,
14 programs, and expenditures that are reasonably expected to increase transportation
15 electrification in the Company's footprint.¹

16 Q. Is the Company asking for any budgetary increases from prior MPSC approvals?

17 A. No, there are no increases to the TEP budget previously approved.²

18 Q. When will the Company file its next TEP?

19 A. In its January 24, 2025 Order in Case No. U-21492, the Commission approved updated
20 TEP filing requirements. In addition, all Michigan investor-owned utilities are required to

¹ Prefiled Direct Testimony and Exhibits of Company witness Myrom, p. 4.

² *Id.*, at, p. 12.

DIRECT TESTIMONY OF ALLAN D. FREEMAN
CASE NUMBER U-21870
PART II

1 file TEPs every two years. This Order established a July 1, 2026 deadline for the
2 Company's next TEP.

3 Q. Does Staff have any suggestions on what it would like to see in the Company's next TEP?

4 A. In addition to the updated filing requirements from Case No. U-21492, Staff would like to
5 see an additional item discussed in the TEP. This trend reflects an emerging topic that is
6 newly relevant to TEPs.

7 Q. What is the first topic?

8 A. On July 4, 2025, The One Big Beautiful Bill Act³ (OBBBA) became federal law. This
9 legislation included several changes to the energy tax credits introduced and expanded by
10 the Inflation Reduction Act of 2022.⁴ The OBBBA changed Internal Revenue Code §30D
11 and §45W, the clean vehicle credits provisions. Their sunset date moved up from December
12 31, 2032 to September 30, 2025. The elimination of these tax credits will impact EV
13 adoption. After an initial spike of new EV registrations to take advantage of the credit
14 before it terminates, it is unclear what will happen to EV adoption after the September 2025
15 end date. Staff recommends that DTE consider these changes and discuss them fully in the
16 Company's 2026 TEP.

17 Q. Does Staff have any opinions on the Company's forecast for EV adoption in its footprint?

18 A. As noted above, the recent OBBBA EV tax credits termination will impact EV adoption.
19 Given this legislation is only approximately three months old, it is unclear the magnitude
20 of this impact. In both its next TEP and rate case, Staff expects to see a thorough discussion
21 of these developments and how EV adoption and load will be impacted.

³ <https://www.congress.gov/bill/119th-congress/house-bill/1/text>, July 2025.

⁴ <https://www.congress.gov/bill/117th-congress/house-bill/5376/text>, August 2022.

DIRECT TESTIMONY OF ALLAN D. FREEMAN
CASE NUMBER U-21870
PART II

1 Q. Is the Company proposing any TEP enhancements?

2 A. Yes, Consumers is proposing two enhancements.

3 Q. What is the first TEP enhancement?

4 A. The Company wants to use weatherized and EV-rated National Electric Manufacturers
5 Association (“NEMA”) 14-50 outlets across all Level 2 rebate categories and NEMA 5-20
6 outlets across all duration Level 1 rebate categories.⁵

7 Q. What is the Company’s rationale for this change?

8 A. Consumers states that the adoption of this recommendation will be “a useful option across
9 the board to reduce infrastructure costs.”⁶ The enhancement does this by simplifying
10 installations and reducing costs for host sites.⁷ These NEMA outlets employ standardized
11 designs. Additionally, this recommendation would allow multifamily locations to utilize a
12 bring-your-own-cord solution.⁸

13 Q. Does Staff support this enhancement?

14 A. Yes, Staff supports this enhancement for two reasons. First, reducing EV infrastructure
15 costs is an excellent rationale. In addition, increased utilization of multifamily charger
16 locations is a worthwhile goal.

17 Q. What is the second proposed enhancement?

18 A. The Company wants to continue its Direct Current Fast Charging (“DCFC”) rebates on a
19 time-limited and selective basis.⁹ Consumers is proposing four alterations to its existing
20 program.

⁵ Prefiled Direct Testimony and Exhibits of Company witness Myrom, p. 12.

⁶ *Id.*, at, p. 13.

⁷ *Id.*, at, p. 12.

⁸ *Id.*, at, p. 13.

⁹ *Id.*

DIRECT TESTIMONY OF ALLAN D. FREEMAN
CASE NUMBER U-21870
PART II

1 Q. What are the proposed changes?

2 A. First, the Company is proposing a DCFC rebate of up to \$50,000 per 150 kW port.¹⁰ Next,
3 Consumers wants to limit the DCFC rebates to communities that do not have at least four
4 150 kW DCFC ports across two or more different host sites.¹¹ Third, the DCFC rebate
5 application will only be available for two years after approval by the Commission. Lastly,
6 the Company will look to select host sites that offer a quality customer experience.¹²

7 Q. Does Staff support the DCFC rebate enhancements?

8 A. Staff supports all these changes. It is consistent with Staff's prior positions that DCFC
9 incentives should work to create a skeleton charger network and not become a permanent
10 program. These enchantments are consistent with this approach. Additionally, these
11 enchantments will steer DCFC rebates towards current charging deserts and avoid
12 subsidizing in areas already with DCFC infrastructure.

13 Q. Please provide a summary of Staff recommendations in this testimony addressing the
14 Company's EV Programs.

15 A. Staff's recommendations are as follows:

16 1. Staff supports both the Company's proposed TEP enhancements.

17 Q. Does this conclude your testimony?

18 A. Yes.

¹⁰ Prefiled Direct Testimony and Exhibits of Company witness Myrom, p. 13.

¹¹ *Id.*

¹² *Id.*, at, p. 14.

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	)	Case No. U-21870
the generation and distribution of	)	
electricity and for other relief.	)	
_____	)	

REBUTTAL TESTIMONY OF
ALLAN D. FREEMAN
MICHIGAN PUBLIC SERVICE COMMISSION

October 21, 2025

**REBUTTAL TESTIMONY OF ALLAN D. FREEMAN
CASE NUMBER U-21870**

1 Q. Are you the same Allan D. Freeman who filed direct testimony in this case?

2 A. Yes, I am.

3 Q. What is the purpose of your rebuttal testimony in this case?

4 A. The purpose of my testimony is to present MPSC Staff's (Staff's) analysis of and position
5 on proposals and arguments made by multiple witnesses related to electric vehicles
6 (EVs).

7 Q. Are you sponsoring any exhibits?

8 A. No.

9 **Direct Current Fast Charger Rebates**

10 Q. What does the Natural Resources Defense Council, the Sierra Club, and the Citizens Utility
11 Board (NRDC/SC/CUB) witness Douglas Jester's testimony propose in regard to Direct
12 Current Fast Chargers (DCFC) rebates?

13 A. NRDC/SC/CUB witness Jester proposes two changes to the DCFC rebate program. First,
14 applicants should be able to request variable rebate amounts.¹ Second, he wants to extend
15 rebate availability to seven years.²

16 Q. What is Staff's position on NRDC/SC/CUB witness Jester's first suggestion?

17 A. Staff is open to his proposal. The federal EV incentive landscape has shifted dramatically
18 this year. Giving Consumers Energy Company (the Company) the flexibility to determine
19 rebate amounts on specific project need may allow for better utilization of the rebate
20 budget. However, the overall DCFC rebate budget should remain unaltered. Increasing the

¹ NRDC/SC/CUB witness Jester's Direct Testimony, p. 21, lines 18-19.

² *Id.*, at, p. 22, lines 1-2.

**REBUTTAL TESTIMONY OF ALLAN D. FREEMAN
CASE NUMBER U-21870**

1 budget at this time would make the future evaluation of this program and the Company's
2 transportation electrification program more difficult.

3 Q. Does Staff support NRDC/SC/CUB witness Jester's second recommendation?

4 A. No. This proposal is an interesting one and a suggestion worthy of consideration. Staff
5 would like this proposal raised in the Company's next rate case. Doing so would allow the
6 Company to present the financial and programmatic impacts of a seven-year rebate window
7 in detail. This would allow for a fuller vetting of the proposal by both the Company and
8 intervenors.

9 Q. Does this conclude your testimony?

10 A. Yes.

1 MR. SONNVELDT: Next, Your Honor, Staff would
2 move to bind in the public and confidential versions of
3 direct testimony by Marceline A. Champion. Her testimony
4 consists of a cover sheet and six pages of questions and
5 answers. She also sponsors two exhibits, Exhibit S-11,
6 and then confidential Exhibit S-11.1.

7 JUDGE THOITS: Are there any objections to the
8 admission of this testimony or these exhibits?

9 Hearing none. The direct testimony of Marceline
10 Champion is bound into the confidential record. Exhibit
11 S-11.0 is admitted to the public record and Exhibit S-11.1
12 is admitted to the confidential record.

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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	)	Case No. U-21870
the generation and distribution of	)	
electricity and for other relief.	)	
	)	

QUALIFICATIONS AND DIRECT TESTIMONY OF
MARCELINE A. CHAMPION
MICHIGAN PUBLIC SERVICE COMMISSION

September 30, 2025

QUALIFICATIONS OF MARCELINE A. CHAMPION
CASE NUMBER U-21870
PART I

1 Q. Please state your full name and business address for the record.

2 A. My name is Marceline A. Champion (she/her), and my business address is 7109 W.
3 Saginaw Highway, Lansing, MI 48917.

4 Q. By whom are you employed and in what capacity?

5 A. I am employed in the Energy Resources Division of the Michigan Public Service
6 Commission (MPSC or Commission). I am a Public Utilities Engineer in the Resource
7 Optimization and Certification Section (ROC), which is responsible for assisting in the
8 implementation of Public Acts 341 and 342 of 2016, as amended by Act 231 of 2023, and
9 evaluating applications for transmission siting pursuant to Public Act 30 of 1995.

10 Q. What is your educational background?

11 A. I earned a Bachelor of Science in Biosystems Engineering, with a Concentration in
12 Ecosystems Engineering, from the College of Engineering and a Minor in Environmental
13 and Sustainability Studies from the College of Natural Science at Michigan State
14 University (MSU) in 2019. In 2021, I attended several training seminars, including the
15 Institute for Public Utilities' Power Grid School I and II, the Wisconsin Public Utility
16 Institute's Regional Transmission Organization Fundamentals training course, and the
17 National Association of Regulatory Utility Commissioners' (NARUC) Fundamentals of
18 Resource Adequacy course. In 2023, I attended NARUC's How To Be An Effective
19 Witness training.

20 Q. What are your professional experiences?

21 A. In 2016, I worked as a Student Assistant for Dr. Eric Hanson in MSU's Department of
22 Horticulture. I maintained several hundred raspberry and blackberry plants for a research
23 study of several emerging organic fertilizers and pesticides, built irrigation systems,

QUALIFICATIONS OF MARCELINE A. CHAMPION
CASE NUMBER U-21870
PART I

1 harvested and recorded yield data by section, and performed other tasks for the department.

2 In 2018, I began working for Enviroweather, a program within MSU, as a Student
3 Technician. I installed, maintained, and programmed new weather stations across
4 Michigan. I conducted several special projects during this time, including completing a
5 feasibility study for a proposed microclimate research project, building a solar-battery
6 powered smart irrigation system, and developing Excel tools for weather data analysis.

7 In 2020, I accepted a position as a Public Utilities Engineer in the ROC Section of
8 the MPSC. I am responsible for evaluating regulated utilities' integrated resource plans
9 (IRPs) and analyzing supply and demand side resource investment. I am involved in
10 reviewing Requests For Proposals (RFP) and Voluntary Green Pricing (VGP) programs. I
11 am responsible for the evaluation of Power Purchase Agreements, Build Transfer
12 Agreements, and Engineering, Procurement, and Construction contracts fulfilling capacity
13 and energy needs identified in approved IRP Proposed Courses of Action and to meet VGP
14 subscriptions. I participated in several MI Power Grid workgroups, where I assisted with
15 all aspects of the stakeholder process and report writing. I am responsible for updating the
16 MPSC's annual regional fuel mix and emissions data page. In 2024, I co-authored the
17 Upper Peninsula Energy Report, pursuant to Section 51(5) of Act 235.

18 Q. Have you previously filed testimony in a contested case before the Commission?

19 A. Yes. I have prepared and filed testimony in the following cases before the Commission:

- 20 • Case No. U-20793: DTE Energy's 2019 DR Reconciliation case;
- 21 • Case No. U-20836: DTE Energy's 2022 Electric Rate Case;
- 22 • Case No. U-21097: NSP's 2021 Electric Rate Case;
- 23 • Case No. U-21090: Consumers Energy Company's 2021 IRP;

**QUALIFICATIONS OF MARCELINE A. CHAMPION
CASE NUMBER U-21870**

PART I

- Case No. U-21224: Consumers Energy Company's 2022 Electric Rate Case;
- Case No. U-21172: DTE Energy's Voluntary Green Pricing Case;
- Case No. U-21374: Consumers Energy Company's Voluntary Green Pricing Case;
- Case No. U-21375: DTE Energy's Voluntary Green Pricing Case;
- Case No. U-21471: METC's Act 30 Certificate of Public Need and Convenience Case;
- and
- Case No. U-21809: Upper Peninsula Power Company's 2025 IRP.

DIRECT TESTIMONY OF MARCELINE A. CHAMPION
CASE NUMBER U-21870
PART II

1 Q. What is the purpose of your testimony?

2 A. I will be presenting MPSC Staff's (Staff) review and recommendations regarding
 3 Consumers Energy Company's (Consumers or the Company) two proposed energy storage
 4 projects, Weadock BESS (Weadock) and Iosco BESS (Iosco), and their accompanying
 5 contracts.

6 Q. Are you sponsoring any exhibits?

7 A. Yes. I am sponsoring the following exhibits:

- 8 • Exhibit S-11.0: Discovery response to Staff on the projected life of the Weadock and
- 9 Iosco projects
- 10 • Confidential Exhibit S-11.1: Discovery response to Staff on the Levelized Cost of
- 11 Storage for the Weadock and Iosco projects

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

13 A. Yes.

14 Q. Please describe the Weadock BESS project.

15 A. Weadock BESS is a Company-owned, 45 megawatt (MW) 4-hour lithium-ion battery
 16 energy storage project to be located at the Weadock Substation in Bay County, with an
 17 expected commercial operations date (COD) of December 21, 2026.¹ It has a 20-year
 18 design life.² The total projected cost is \$67.45 million.³ The Levelized Cost of Storage
 19 (LCOS) is [REDACTED].⁴

20 Q. Please describe the Iosco BESS project.

¹ Prefiled Direct Testimony of Company witness Thomas Clark, p. 7.

² Staff Exhibit S-11.0, p. 1.

³ Prefiled Direct Testimony of Company witness Clark, p. 9.

⁴ Confidential Staff Exhibit S-11.1, p. 1.

DIRECT TESTIMONY OF MARCELINE A. CHAMPION**CASE NUMBER U-21870****PART II**

1 A. Iosco BESS is a Company-owned, 30 MW 4-hour lithium-ion battery energy storage
2 project to be located at the Iosco Substation in Iosco County, with an expected COD of
3 December 21, 2026.⁵ It has a 20-year design life.⁶ The total projected cost is \$49.9 million.⁷

4 The LCOS is [REDACTED]⁸

5 Q. What can the LCOS of these two projects be compared to?

6 A. The Company has several previously approved storage projects, but these projects are all
7 significantly larger than the two projects presented in this case. The Company's 2021 IRP
8 included a modeled energy storage proxy resource, which is far closer in size to the two
9 projects. This option also presents a problem in that it is 4 years out of date and does not
10 represent an actual project.

11 Q. How do the Weadock and Iosco projects compare to the Company's previous projects and
12 its 2021 IRP proxy?

13 A. The previous projects and IRP proxy LCOS values come in at around \$145/MWh, roughly
14 [REDACTED] than the two proposed projects.

15 Q. Is there an external source for comparison of the LCOS values?

16 A. Yes. Lazard Inc., a financial advisory and asset management firm, conducts an annual
17 analysis of energy generating technologies, the Levelized Cost of Energy+ Report. Its most
18 recent version was published on June 16, 2025. Included in this report is an analysis of
19 LCOS for energy storage resources.

20 Q. Does this report contain a category of energy storage comparable to the two proposed
21 projects?

⁵ Prefiled Direct Testimony of Company witness Clark, pp. 9-10.

⁶ Staff Exhibit S-11.0, p. 1.

⁷ Prefiled Direct Testimony of Company witness Clark, p. 11.

⁸ Confidential Staff Exhibit S-11.1, p. 2.

DIRECT TESTIMONY OF MARCELINE A. CHAMPION
CASE NUMBER U-21870
PART II

1 A. Yes. The closest category to the two proposed projects is the Utility-Scale Standalone (100
2 MW, 4-Hour) category. This category's LCOS ranges from \$115/MWh to \$254/MWh.⁹

3 Q. How do Weadock and Iosco compare to the Utility-Scale Standalone (100 MW, 4-Hour)
4 category?

5 A. Both Weadock and Iosco fall within that range of LCOS values.

6 Q. Do these projects align with the Company's most recently approved Integrated Resource
7 Plan (IRP) in Case No. U-21090?

8 A. Yes. In the June 23, 2022, settlement agreement, the Company agreed to the addition of 75
9 MW of energy storage resources between 2024 and 2027. These projects combined will
10 provide 75 MW of 4-Hr storage within that time period.

11 Q. Has Staff reviewed the contracts for Weadock and Iosco?

12 A. Yes. Staff reviewed the contracts for the two storage projects on July 30, 2025.

13 Q. What is Staff's recommendation to the Commission?

14 A. Staff recommends the Commission approve these contracts. They are consistent with the
15 Company's approved IRP settlement agreement and the cost is within the expected range.

16 Q. Does this conclude your testimony?

17 A. Yes.

⁹ [Levelized Cost of Energy+ Report](#), p. 19.

1 MR. SONNEVELDT: Next, Your Honor, Staff would
2 move to bind in the direct testimony of Paul R. Ausum.
3 His testimony consists of a cover sheet and 15, or sorry,
4 excuse me, 16 pages of questions and answers. He also
5 sponsors Exhibits S-15.0 through S-15.12.

6 JUDGE THOITS: Are there any objections to the
7 admission to this testimony or these exhibits?

8 Hearing none. The direct testimony of Paul
9 Ausum is bound into the record and Exhibits S-15.0 through
10 S-15.12 or admitted.

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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) Case No. U-21870
the generation and distribution of)
electricity and for other relief.)
)

QUALIFICATIONS AND DIRECT TESTIMONY OF
PAUL R. AUSUM
MICHIGAN PUBLIC SERVICE COMMISSION

September 30, 2025

QUALIFICATIONS OF PAUL R. AUSUM
CASE NUMBER U-21870
PART I

1 Q. Please state your name and business address.

2 A. My name is Paul R. Ausum, and my business address is 7109 W. Saginaw
3 Highway, Lansing, Michigan 48917.

4 Q. By whom are you employed and in what capacity?

5 A. I am employed as an Economic Analyst in the Resource Adequacy & Forecasting Section
6 of the Energy Resources Division of the Michigan Public Service Commission (MPSC or
7 Commission).

8 Q. What are your responsibilities in your current position?

9 A. I am responsible for the analysis of energy sales (deliveries, load) and peak demand
10 forecasts in cases that come before the Commission, including rate cases and integrated
11 resource plans (IRPs). This analysis leads to MPSC Staff (Staff) positions and
12 recommendations.

13 Q. Please outline your educational background and work history at the Commission.

14 A. I graduated with a Bachelor of Science degree in Economics from Oakland University in
15 December 2018. From November 2019 to August 2022, I worked as an Economic
16 Analyst in the Act 304 & Sales Forecasting Section¹ of the Energy Operations Division
17 of the Commission. In this role, I conducted analysis of Gas Cost Recovery (GCR) and
18 Power Supply Cost Recovery (PSCR) cases and provided analysis and input that
19 supported Staff positions in rate cases. In August of 2022, I assumed my current
20 position. I have attended various courses on regulated utility companies, including the
21 Accounting and Ratemaking course presented by Michigan State University's Institute of
22 Public Utilities (IPU) in February 2021, as well as IPU's Fundamentals course in the

¹ In 2022, this section was renamed as the Energy Cost Recovery & Generation Operations Section.

QUALIFICATIONS OF PAUL R. AUSUM
CASE NUMBER U-21870
PART I

theory, principles, and practice of economic regulation of utility companies 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:

<u>Case Number</u>	<u>Company</u>	<u>Type of Case</u>
U-20541	Consumers Energy-Gas	GCR Plan
U-20542	Consumers Energy-Gas	GCR Reconciliation
U-20642	DTE Gas	Rate Case
U-20650	Consumers Energy-Gas	Rate Case
U-20816	DTE Gas	GCR Plan
U-20817	DTE Gas	GCR Reconciliation
U-20822	SEMCO Energy	GCR Plan
U-20823	SEMCO Energy	GCR Reconciliation
U-20836	DTE Electric	Rate Case
U-20940	DTE Gas	Rate Case
U-21046	Alpena Power Company	PSCR Plan
U-21064	DTE Gas	GCR Plan
U-21070	SEMCO Energy	GCR Plan
U-21148	Consumers Energy-Gas	Rate Case
U-21193	DTE Electric	Integrated Resource Plan

QUALIFICATIONS OF PAUL R. AUSUM**CASE NUMBER U-21870****PART I**

	<u>Case Number</u>	<u>Company</u>	<u>Type of Case</u>
1			
2	U-21255	Alpena Power Company	PSCR Plan
3	U-21297	DTE Electric	Rate Case
4	U-21308	Consumers Energy-Gas	Rate Case
5	U-21461	Indiana Michigan Power	Rate Case
6	U-21540	Michigan Gas Utilities Corp.	Rate Case
7	U-21585	Consumers Energy-Electric	Rate Case
8	U-21806	Consumers Energy-Gas	Rate Case
9	U-21860	DTE Electric	Rate Case

DIRECT TESTIMONY OF PAUL R. AUSUM
CASE NUMBER U-21870
PART II

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

2 A. My testimony will present Staff's analysis of the May 2026 – April 2027 Test Year forecast
3 sponsored by Consumers Energy Company (Consumers or the Company) witness Eugène
4 M.J.A. Breuring in Exhibits A-5 and A-15. My analysis includes review of the number of
5 customers, energy sales to those customers, and system peak demand used to design
6 proposed rates.

7 Q. Are you sponsoring any exhibits?

8 A. Yes. I am sponsoring 13 exhibits:

9	<u>Exhibit</u>	<u>Description</u>
10	S-15.0	Staff's Recommended Adjustment to Test Year Commercial Deliveries
11	S-15.1	Part III Filing Attachment 027
12	S-15.2	Company Residential and Commercial MWh Forecast Equations
13	S-15.3	Part III Filing Attachment 016
14	S-15.4	Comparison of MetrixND Model Test Year Forecasts and Part III
15		Attachment 016 Test Year Forecasts
16	S-15.5	Discovery Response U21870-ST-CE-0085
17	S-15.6	Discovery Response U21870-ST-CE-0086
18	S-15.7	Model Coefficients and July 2024 – March 2025 Out of Sample Test on
19		Individual Company Commercial Forecasting Models
20	S-15.8	Discovery Response U21870-ST-CE-0084
21	S-15.9	Staff Model Coefficients
22	S-15.10	Comparison of Company and Staff Model Statistics
23	S-15.11	Out-of-Sample Comparison of Company and Staff Models
24	S-15.12	Discovery Response U21870-ST-CE-0087

DIRECT TESTIMONY OF PAUL R. AUSUM**CASE NUMBER U-21870****PART II****ADJUSTMENTS TO TEST YEAR BILLING DETERMINANTS**

1
2 Q. What recommendations do you have for the Commission regarding Consumers' test year
3 electric deliveries forecast in this case?

4 A. I recommend that the Company's forecast of deliveries to commercial customers be
5 increased by 204,656 megawatt hours (MWh) for customers receiving bundled service and
6 16,308 MWh for customers receiving choice (retail open access (ROA)) service. My
7 adjustment affects cycle-billed sales and is presented in Staff Exhibit S-15.0, column (f),
8 lines 32 and 41. Within my Staff Exhibit S-15.0, the recommended adjustment is presented
9 alongside and in the same format as Company witness Breuring's Exhibit A-15, Schedule
10 E3.

11 Q. Do you have any recommendations for the Commission regarding Consumers' test year
12 customer count forecast in this case?

13 A. I am not recommending that the Commission alter the Company's forecast of customers it
14 expects to serve in the test year.

15 Q. Do you have any recommendations for the Commission regarding the Company's test year
16 peak demand forecast?

17 A. I am not recommending that the forecast of peak demand be adjusted at this time.

18 Q. Why are you recommending adjustments to the test year deliveries forecast?

**DIRECT TESTIMONY OF PAUL R. AUSUM
CASE NUMBER U-21870
PART II**

1 A. The adjustments are the result of alterations made to the econometric regression models
2 the Company uses to forecast electricity demand² for the major customer classes it serves.³
3 The Company's sales, peak demand, and customer models in their native .NDM⁴ format
4 were requested by Staff via audit request and are included as workpapers to my testimony
5 and exhibits.⁵ Staff analyzed the Company's forecasting models in their original format,
6 and, using the Company's own criteria for model evaluation, was able to improve upon the
7 model outputs to create a more accurate forecast of MWh deliveries.

**BRIEF DESCRIPTION OF SELECT COMPANY MWh MODELS AND STAFF
MODIFICATIONS TO THEM**

RESIDENTIAL MODEL

11 Q. Please describe the components of the Company's residential deliveries forecasting models
12 in their native format.

13 A. Company witness Breuring provides an overview of the forecasting process in his direct
14 testimony, but the ability to analyze the sales and customers in their native formats yields
15 some additional insight. Regarding the residential forecast, the Company's MWh
16 deliveries model is composed of two separate use-per-customer regression models
17 constructed with monthly measured energy efficiency savings from the Company's energy

² Here, the term demand is used to refer to the amount of electrical energy delivered to the meters of the Company's customers. Peak demand, on the other hand, is a function of the highest average amount of energy recorded on the Company's system over a given period. Energy (MWh) is measured over a timespan (e.g. a month, season, year) in intervals (e.g. 15 minutes). The measured interval energy values are divided by the interval (15 minutes = 0.25 hours), giving units of power in megawatts (MW). The highest of these MW values in the timespan of interest (month, season, year) is that period's peak demand.

³ Company witness Breuring describes the general methodology, process, evaluation criteria, variable selection, and data sources that undergird the Company's demand and customer forecasting philosophy on page 4, lines 5 through page 9, line 17 of his direct testimony in this case.

⁴ .NDM is the suffix for an Itron, Inc. MetrixND file. MetrixND is the statistical modeling software used by the Company and many other electric and natural gas utilities to analyze and forecast energy demand and customer counts. To view the forecast models in their native format, a license to install MetrixND is needed.

⁵ I have included as a workpaper a copy of the forecasting models with Staff's alterations.

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1 efficiency team added back in.⁶ The use-per-customer with efficiency savings added is
2 modeled as a function of weather (in the form of heating and cooling degree days), binary
3 variables, billing days, a variable that tracks the closure of the economy due to COVID-19
4 and its eventual reopening, and several binary variables that explain large variations in
5 individual months that do not occur elsewhere in the time series. One model captures the
6 effect of prior usage with an autoregressive term, and the other model uses recorded usage
7 from the prior twelve months to similarly capture the effect of prior usage on current usage.
8 The predicted values from these use-per-customer models are weighted and then added
9 together before being multiplied by the residential customer forecast and combined with
10 the external forecasts for electric vehicles (EVs) and distributed generation (DG). After
11 adding in the expected load from EVs and the expected reductions in sales due to increasing
12 levels of distributed generation, the Company sponsored energy efficiency savings are
13 subtracted from the model. Staff Exhibit S-15.1 shows the explanatory variables that go
14 into the Company's models, as well as the statistics that demonstrate the performance of
15 models over the January 2014 – June 2024 sample of observations that was used estimate
16 the model equations. Staff Exhibit S-15.2 shows how they combine to form the residential
17 forecast.

18 Q. Does Staff take issue with the Company's residential forecasting models and their outputs?

⁶ The Company files energy waste reduction (EWR) plans that set goals for annual reductions in deliveries. The projected reductions in sales must be attributable to Company actions (explicitly defined in the EWR plan) that incentivize the efficient use of electricity within the Company's service territory. At a portfolio (aggregate) level, the Company's plan **must** decrease customer consumption of electricity. Plans are reconciled and the achieved level of sales reductions are verified by Staff. In adding the historic efficiency savings to recorded sales, the modeler seeks to isolate the effect of Company sponsored reductions in usage from the other factors that influenced usage in the past and will continue to influence usage into the future.

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1 A. Not at this time. Staff did inquire as to the rationale behind the weights applied to each
2 model, included as Staff Exhibit S-15.5. As the Company indicates, the model with less
3 weight (ResDelCycUse_XEE2) was created to give “weight to the previous twelve months,
4 where the original model (ResDelCycUse_XEE) uses the full history with the regression
5 modeling.” However, both models used the same number of observations to train the
6 model, so it appears that both models use the “full” history of data, unless the Company is
7 referring to something else. Aside from the choice of different binary variables, a key
8 difference between the two models is a “ResUseCalibration” variable in the model with
9 more weight. This variable is not explained in Company witness Breuring’s testimony.

10 Q. Are there any other adjustments made to the residential forecast?

11 A. Yes. Everything I’ve described up to this point happens within MetrixND. The forecast
12 is then altered before being included in the Exhibits and Filing Attachments that make up
13 the Company’s rate case application. Staff Exhibit S-15.4 shows the Company’s
14 MetrixND forecast for each month of the May 2026 – April 2027 test year, the monthly
15 forecast for the same period that was included with the Part III Attachment 016.⁷ For most
16 months, there exists a difference in the MWh forecast that is not explained by Company
17 witness Breuring in testimony. In future rate cases, the Company should explain how it
18 derived the adjustments to the MetrixND forecasts and why they are necessary.

19 Q. Do you have any recommendations to the Commission regarding the residential deliveries
20 forecast?

21 A. In future cases, the Company should provide an explanation as to how this
22 “ResUseCalibration” variable is derived. The Company should also give more explanation

⁷ Part III Attachment 016 is included as Staff Exhibit S-15.3.

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as to why two models are needed to predict residential deliveries. The Company should also provide an explanation as to why the forecasts in MetrixND differ so largely from what is contained in the Part III Attachment 016, aside from the cycle to calendar billed conversion.

COMMERCIAL MODEL

Q. Please describe the components of the Company's commercial deliveries forecasting models in their native format.

A. Similar to the residential modeling process, the Company takes out energy efficiency before utilizing two separate models, which are then weighted and combined with an external EV forecast. Aside from the various explanatory variables in each model, a key difference in the two models is the fact that one is a model of use-per-customer, while the other is a model of total commercial deliveries. Staff Exhibit S-15.2 shows that the use-per-customer model is weighted less heavily than the total commercial deliveries model.⁸ Just like the residential models, Staff inquired as to the reasoning underlying the weights given to each model, and the Company's response is presented as Staff Exhibit S-15.6. The Company provided much less explanation than the residential forecast as to weightings used in the commercial models, only providing that the weighting scheme "provides weight to each model to increase flexibility in modeling."

Q. Does Staff agree that the combination of the weighted models produces a more accurate forecast than the predictions yielded by the output of each model separately?

A. No. Staff Exhibit S-15.7 contains an examination of the model statistics and an out-of-sample test of accuracy for each commercial deliveries model. The Exhibit shows that the

⁸ ComDelCycUse_XEE is given a weight of 0.4 and ComDelCyc_XEE is given a weight of 0.6.

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commercial use-per-customer model is better able to explain variations in customer usage (as measured by adjusted R^2) and is less prone to error (as measured by Mean Absolute Percentage Error). This demonstrates that the use-per-customer model has more explanatory power than the total deliveries model. For further evidence that the use-per-customer model is a better predictor of future deliveries, Staff compared the predictions made by each model on out-of-sample data from July 2024 – March 2025. Staff Exhibit S-15.7 also shows that the predictions yielded by the Company's use-per-customer model fell closer to both actual and weather normal cycle billed deliveries in the test set. In future rate case filings, the Company should explain why it requires two models to forecast commercial load, especially when it appears that one model (use-per-customer) does a much better job of predicting commercial customer usage.

Q. How is choice load considered in the commercial forecasting models?

A. The delivery model outputs are inclusive of both bundled *and* choice load. The historical ratio of choice deliveries to total deliveries is recorded as a percentage and is then modeled with binary variables corresponding with each month of the year as explanatory variables. The percentages resulting from this model are applied to each month of the commercial deliveries model to represent expected ROA load in each month. Once expected energy efficiency savings are added back into the model, the Company calculates the forecasted growth in commercial load relative to 2023 and applies this same growth rate to choice load throughout the forecast horizon.

Q. Does the Company calculate a historical percentage and forecasted growth rate for the number of commercial choice customers it expects to serve?

A. No.

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1 Q. Please describe how the Company forecasted commercial customer count.

2 A. The Company's regression model uses population, a lagged dependent variable, and an
3 autoregressive variable to forecast commercial customer count. When looking at the data
4 that was inputted into the model, Staff noticed that the historical customer count only
5 included the number of bundled commercial customers and did not include choice
6 customers. This differs from the commercial delivery models that input a combination of
7 bundled and choice customers. Staff queried the Company as to why choice customers are
8 not included in any of the MetrixND historical data and forecasts used in this case. The
9 Company's response is included as Staff Exhibit S-15.8. Due to their relatively static
10 nature, the number of choice customers the Company expects to serve in the test year was
11 not modeled explicitly in the commercial customer regression model. Instead, the
12 Company used the most recent monthly choice customer count figure⁹ and then held the
13 number of choice customers fixed at this amount in the test year. Staff was unable to find
14 the choice commercial count added anywhere into MetrixND and the commercial delivery
15 forecast.

16 Q. Does Staff take issue with the way that commercial customer count is included in the
17 Company's commercial deliveries model?

18 A. While Staff does not take issue with the Company's method of forecasting commercial
19 customer count, the omission of choice customers becomes problematic when the
20 Company forecasts deliveries with a use-per-customer model. If use-per-customer is
21 calculated and then modeled in MetrixND with choice load included, but the forecast of

⁹ In this case, the last historical observation used to train the regression model (i.e., estimate the model coefficients) was June 2024, so choice customers over the forecast horizon are assumed to remain static at 844.

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commercial customers does not include choice customers, the resulting MWh forecast has the potential to be understated.¹⁰ Staff's recommended adjustment adds the expected number of choice customers (844 per month) back into commercial customer counts before multiplying forecasted use-per-customer, which provides a better estimate of commercial MWh load in the test year.

Q. What other modifications did Staff make to the Company's commercial models?

A. Staff's recommended commercial models focus solely on use-per-customer multiplied by the number of customers. The ability to measure usage separate from the number of customers is useful for a class of over 200,000 customers. Staff began by adding together historical bundled and choice load, *as well as* historical bundled and choice customer counts, which were sourced from previous Company rate case filing attachments and annual P-521 reports to the Commission. The combined load was divided by the combined customer count figures dating back to January 2014, the first period in the Company's training set. The resulting commercial kWh usage per customer became the dependent variable in Staff's forecast models. Staff's recommended model uses the same degree day, commercial use calibration,¹¹ cycle billing days, and COVID-19 variables included in the Company's model, but omits unnecessary binary variables and substitutes non-manufacturing employment from the Company's list of economic indicators as an explanatory economic variable, instead of the Company's service employment variable. Both variables are measures of employment in the state and come from the same source of

¹⁰ In a use-per-customer model, total MWh are calculated as the product of kWh usage per customer and the number of customers served in a given month. The value in modeling usage separate from customer count is the ability to measure whether change in total load is due to changes in average individual customer consumption, or changes in the total number of customers served.

¹¹ Similar to the residential model, no explanation is provided as to how this variable is derived. In future cases, explanation should be given as to the source and reasoning for this variable's inclusion in the model.

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economic data included within the Company's MetrixND model file, but non-manufacturing employment is a slightly broader measure of economic activity that still corresponds with the Company's definition of commercial usage in its rate book.¹² The only other key difference in Staff's recommended model is the inclusion of an intercept term within the regression equation. Unless a complete set of seasonal binary variables are used,¹³ the inclusion of an intercept term is an accepted practice in regression modeling. Staff's model coefficients and associated statistics are presented in Staff Exhibit S-15.9, and a comparison of the model with the Company's use-per-customer and aggregate load models is presented in Staff Exhibit S-15.10. Staff's model has both a higher adjusted R² statistic, meaning that more of the variation in commercial use-per-customer is explained by Staff's choice of explanatory variables, and Staff's model has lower average in-sample mean absolute percentage error (MAPE), meaning that the fitted values in Staff's model fall closer to actuals than the Company's. By the Company's stated criteria, Staff's model is the more reasonable choice for forecasting commercial deliveries in the test year.

Q. Did Staff conduct any out-of-sample testing to further validate the choice of its model?

A. Yes. The Company included historical deliveries and customers from January 2020 through March of 2025 with Part III Attachment 014 in this case. Because the period used for estimating the regression models ends with June 2024, the period of July 2024 – March 2025 is a prime test set to analyze the predictive power of each model. Staff Exhibit S-

¹² Page A-26.00 of the Company's rate book defines Commercial Usage as "Usage for applications, other than residential, associated with businesses and other establishments which qualify for a **nonmanufacturing industry code** under the most current edition of the Standard Industrial Classification Manual. In addition to the usual retail and service businesses included are communication, transportation, utility, recreation, education, religious, social, and governmental businesses or institutions. It also includes usage for business offices and common use facilities associated with centrally metered complexes (apartments, condominiums, and trailer parks)."

¹³ For example, 12 binary variables corresponding to each month, or 4 binary variables corresponding to each quarter.

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15.11 contains a comparison of the Company's and Staff's MetrixND model predictions for the out-of-sample test period, alongside actual sales and weather normal actual sales over the same period. Staff's model had a lower out-of-sample MAPE on both actual and, more importantly, weather normal data, further validating the usage of Staff's model.

Q. Were there any additional adjustments performed on Staff's commercial deliveries model?

A. Yes. Staff noted a discrepancy in the forecasted sales in the Company's MetrixND files and what was included in the Part III Attachment 016, which contains monthly class level and rate category sales from January 2025 – December 2029. For each month of the test year, there exists a difference in the MetrixND and Attachment 016 forecasts. When asked about this, the Company states "[t]he final cycle-billed deliveries are adjusted for unbilled sales (when looking at calendar deliveries in Part III), as well as adjustments to overall model outputs when looking at overall monthly, quarterly, and annual reasonableness."¹⁴ The conversion from cycle to calendar deliveries is understood by Staff, but is not germane to the question, as attachment 016 included cycle deliveries alongside calendar deliveries in this case. Because cycle deliveries are used as forecasted billing determinants, they are what Staff used to compare its model with the Company's. With nothing else to explain how the Company arrived at the forecast contained in Attachment 016, and in order to achieve a comparable test year forecast, Staff computed the difference between the Company's MetrixND forecast and the commercial deliveries forecast in Attachment 016 for each month of the test year, and then applied that same difference to Staff's MetrixND commercial deliveries forecast. In future rate case applications, the Company should

¹⁴ Discovery response included as Staff Exhibit S-15.12.

DIRECT TESTIMONY OF PAUL R. AUSUM**CASE NUMBER U-21870****PART II**

1 explain why the predicted values from the models in MetrixND are adjusted so heavily
2 before they appear in the Part III Attachment 016.

3 Q. How did Staff allocate its recommended commercial deliveries amongst bundled and
4 choice customers?

5 A. Staff computed the percentage of choice deliveries as a component of total commercial
6 deliveries for each month of the test year in the same manner as the Company, by
7 calculating the growth in total commercial deliveries resulting from the Staff's model
8 relative to 2023 and applying that forecasted growth rate to choice load. Bundled deliveries
9 are calculated as the difference between total commercial deliveries and choice deliveries.

10 Q. How did Staff allocate the incremental class level forecast amongst the rate schedules in
11 the test year?

12 A. Staff allocated the additional class level sales and customers in its model amongst the rate
13 schedules according to the Company's 2024 P-521 Annual Report.

SUMMARY

14
15 Q. Please summarize your recommendations to the Commission in this case.

16 A. I am recommending that the forecast of cycle-billed commercial deliveries, as presented
17 by the Company in Part III Attachment 016, be increased by 204,656 MWh for bundled
18 customers and 16,308 MWh for choice customers.

19 Q. Please summarize any additional recommendations that you have for the Company in
20 future rate case filings.

21 A. I recommend that the Company provide more detail as to the origin of the calibration
22 variables in the residential, commercial, and industrial deliveries models. The Company

DIRECT TESTIMONY OF PAUL R. AUSUM**CASE NUMBER U-21870****PART II**

1 should also explain why the MetrixND model outputs are adjusted before they appear in
2 the Part III Attachment 016.

3 Q. Does this conclude your testimony at this time?

4 A. Yes, it does.

1 MR. SONNEVELDT: Next, Your Honor, Staff moves
2 to bind in the direct testimony of Anna Schiller. Her
3 direct testimony consists of a cover sheet and 25 pages of
4 questions and answers. She also sponsors Exhibit S-19.0
5 and Exhibit S-19.1.

6 JUDGE THOITS: Are there any objections to the
7 admission of this testimony or these exhibits?

8 Hearing none. The direct testimony of Anna
9 Schiller is bound into the record, and Exhibits S-19.0 and
10 Exhibit S-19.1 are admitted.

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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	)	Case No. U-21870
the generation and distribution of	)	
electricity and for other relief.	)	
	)	

QUALIFICATIONS AND DIRECT TESTIMONY OF
ANNA N. N. SCHILLER
MICHIGAN PUBLIC SERVICE COMMISSION

September 30, 2025

QUALIFICATIONS OF ANNA N. N. SCHILLER
CASE NUMBER U-21870
PART I

1 Q. Please state your full name and business address for the record.

2 A. My name is Anna N. N. Schiller. My business address is the Michigan Public Service
3 Commission's work site at 7109 West Saginaw Highway, Lansing, Michigan 48917.

4 Q. By whom are you employed and in what capacity?

5 A. I am employed by the Michigan Public Service Commission (MPSC or Commission) in
6 the Energy Resources Division. I am a Public Utilities Engineer Specialist in the
7 Distribution Planning Section.

8 Q. Please describe your educational background.

9 A. I earned a Bachelor of Science in Biosystems Engineering from Michigan State
10 University (MSU) in 2018. I successfully completed the Fundamentals of Engineering
11 examination in May of 2018. Since joining the Commission, I have attended various
12 training programs sponsored by Electric Utility Consultants, Inc. (EUCI); the
13 Organization of Midcontinent Independent System Operator (MISO) States; and the
14 MSU Institute of Public Utilities.

15 In April 2023, I completed courses by EUCI in overhead and underground
16 distribution systems, substation design, electric distribution system planning and safety,
17 and performance-based regulation. I have completed additional EUCI course material
18 since then, including a course on Distribution Pole Safety in August 2024, and a course
19 on Energy Burden and Affordability in July 2025. I also completed NARUC-NASEO
20 training on Integrated Distribution Planning in March 2025 and on Comprehensive
21 Electric Planning in April 2025. I am a member of the ongoing Regulatory Collaborative
22 effort hosted by the Rocky Mountain Institute (RMI), which reviews novel ideas and

QUALIFICATIONS OF ANNA N. N. SCHILLER
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PART I

tackles emerging issues through a cohort of public utility commission members across many member states.

Q. Please describe your professional work experience.

A. In January of 2015, I began working as an Engineering Assistant under the Infrastructure Planning and Facilities Power and Water department at MSU. As an Engineering Assistant, I worked both part- and full-time to assist in the oversight analysis of both power and water engineering at the T.B. Simon Power Plant.

In June 2018, I accepted a position as a Public Utilities Engineer in the Resource Adequacy and Retail Choice Section of the MPSC, which has since become the Resource Adequacy and Forecasting Section. In May 2023, I accepted a position as a Public Utilities Engineer in the Distribution Planning Section of the MPSC. At the Commission, I am part of the group responsible for assessing the reasonableness and feasibility of utility distribution planning efforts.

Q. Have you previously participated in cases before the MPSC?

A. Yes. I have testified in the following cases:

<u>Case No.</u>	<u>Description</u>
U-20350	UPPCO Integrated Resource Plan 2019
U-20471	DTE Electric Integrated Resource Plan 2019
U-20591	Indiana Michigan Integrated Resource Plan 2019
U-21090	Consumers Energy Integrated Resource Plan 2020
U-21183	Indiana Michigan Integrated Resource Plan 2022
U-21193	DTE Electric Integrated Resource Plan 2022
U-21389	Consumers Energy Rate Case 2023

QUALIFICATIONS OF ANNA N. N. SCHILLER**CASE NUMBER U-21870****PART I**

I have also recently participated in the following recent cases, including the assistance of other witnesses and the preparation of MPSC Staff filings:

<u>Case No.</u>	<u>Description</u>
U-20147	Michigan Distribution Planning
U-21251	MI Power Grid Distribution System Data Access
U-21305	Third Party Utility Audit with the Liberty Consulting Group
U-21860	DTE Electric Rate Case 2025

DIRECT TESTIMONY OF ANNA N. N. SCHILLER
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PART II

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

2 A. I am providing testimony regarding distribution planning topics related to the Consumers
3 Energy (Consumers or the Company) rate case testimony; specifically, the Company's
4 Demand Failures program and synchronicity with existing MPSC Docket Nos. U-20147
5 and U-21305. I also discuss integration between the Company's rate cases and the
6 Company's Electric Distribution Infrastructure Investment Plans (EDIIP).

7 My testimony is divided into topic sections as follows:

8 **Inspections within the Demand Failures Program**

9 **Distribution System Plan Alignment**

10 **Coordination with MPSC Case No. U-21305**

11 Q. Are you sponsoring any exhibits?

12 A. Yes, I am sponsoring the following exhibit(s):

13 S-19.0: Company Discovery

14 S-19.1: SAIDI Trendline Datasheet

15 Q. Were these exhibits made by you or under your direction?

16 A. Yes.

17 **Inspections within the Demand Failures Program**

18 Q. Please describe the LVD Lines Demand Failures subprogram.

19 A. Company witness Jennifer M. Partlan presents the LVD Lines Demand Failures as a
20 subprogram under the unplanned distribution capital investment, part of the Demand
21 Failures program. This subprogram "includes capital expenditures incurred during
22 customer interruption restoration, or during the repair or replacement of LVD equipment

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1 due to unanticipated failure.”¹ It does not include projects planned in advance and is meant
2 for quick response(s) to system interruptions. The subprogram is split into the investment
3 categories of Service Restoration Orders and Security Assessment Inspection Orders. The
4 LVD Lines Demand Failures capital subprogram is provided in Company Exhibit No. A-
5 113 (MPK-3), including assessment and inspection costs under the Security Assessment
6 Inspection Order investment category.

7 Q. Please explain Staff’s review of these assessment and inspection costs.

8 A. Staff’s review of this subprogram recognizes that a portion of the assessment and
9 inspection costs within the LVD Lines Demand Failures subprogram are capitalized.²
10 These LVD line inspections occur over the entire LVD system annually.³ Company
11 responses to Staff discovery requests in the examination of this program, compiled in Staff
12 Exhibit No. S-19.0, provide additional detail. The Company estimates a cost of \$1.2
13 million for both internal and contracted labor related to the inspections.⁴ Response ST-CE-
14 0304 confirms that these security assessments are the same as visual line inspections.
15 Further, the Company’s response ST-CE-0306 demonstrates the Company’s view that the
16 inspections are included as components of engineering and supervision of the construction
17 work, referring to the Electric Plant Instructions, Section 3, subsection 11 of the FERC
18 Uniform System of Accounts (USOA), adopted in MPSC Docket No. U-14811. The
19 Company explains that the inspection activity is classified under the USOA as
20 “Engineering and supervision” which “includes the pay and expenses of engineers,

¹ Prefiled Direct Testimony of Company witness Partlan, MPSC Case No. U-21870, p. 17.

² *Id.*, at, p. 19.

³ *Id.*, at, p. 20.

⁴ Staff Exhibit No. S-19.0, ST-CE-0306, p. 4.

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PART II

surveyors, draftsmen, inspectors, superintendents and their assistants applicable to the construction work.”⁵

Q. Does Staff believe these costs are correctly categorized?

A. No. Staff is not convinced that the inspections are interpreted correctly in subsection 11. The work is better classified under the Operating Expense Instructions, Section 2. Section 2 expenses of the USOA includes “[i]nspecting, testing, and reporting on condition of plant specifically to determine the need for repairs, replacements, rearrangements, and changes and inspecting and testing the adequacy of repairs which have been made.” In addition, the Company itself cites a 2015 EPRI report in the explanation of this subprogram within Company witness Partlan’s testimony for which those practices are listed as systems maintenance.⁶ It is important for utilities to classify expenses correctly.

Q. Does Staff agree the overhead line inspections are necessary?

A. Yes. As presented, Staff supports the maintenance of the overhead system. The classification of these costs is the concern.

Q. Is Staff recommending a capital disallowance and operations and maintenance (O&M) credit based on its findings?

A. No. Instead, Staff recommends the Commission direct the Company to: 1) provide a thorough breakdown of inspection costs applied across all capital programs/subprograms, 2) support why these costs are appropriately classified as capital instead of O&M with reference(s) to accounting guidance, and 3) amend the classification of these expenditures in the Company’s next rate case, where necessary, based on the analysis. The Company

⁵ Staff Exhibit No. S-19.0, ST-CE-0306, p. 5.

⁶ Prefiled Direct Testimony of Company witness Partlan, MPSC Case No. U-21870, p. 19.

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should explain why section 2 under the Operating Expense Instructions of USOA is not appropriate and why section 3 under the Electric Plant Instructions of USOA is appropriate under recommendation #2 above. Staff witness Ally Durfee further discusses Staff's review of the Demand Failures programs and the proposed disallowances therein.

Distribution System Plan Alignment

Q. Please briefly describe the Company's distribution system planning efforts.

A. In 2023, the Company filed a Distribution System Plan (DSP) to MPSC Docket No. U-20147 as ordered previously by the Commission⁷ and containing items agreed to in the settlement of MPSC Case No. U-21224.⁸ The Company has previously filed such plans as directed in 2018⁹ and 2021¹⁰ and has been ordered to provide its next DSP in 2026.¹¹ The Company has historically referred to these plans as Electric Distribution Infrastructure Investment Plans (EDIIP) or as the Reliability Roadmap. During this period, the Commission continued to seek transparent and distinct details into the long-term planning efforts of the distribution system outside of the annual rate case proceedings. In mid-2025, the MPSC issued guidelines for future DSPs after receiving feedback and comments from participating utilities, including Consumers Energy.¹²

The Company's 2023 DSP was reviewed by Staff and interested parties, who submitted comments on the contents and planning process.¹³ The Commission issued an order on September 26, 2024 which, among other topics, found that the Company's 2023

⁷ [September 8, 2021 Commission Order](#) in MPSC Case No. U-20147.

⁸ [January 19, 2023 Commission Order](#) in MPSC Case No. U-21224.

⁹ [Consumers Energy EDIIP](#) in Case No. U-20147. April 13, 2018.

¹⁰ [Consumers Energy's Final EDIIP 2021-2025](#) in Case No. U-20147. June 30, 2021.

¹¹ [July 10, 2025 Commission Order](#) in MPSC Case No. U-20147, p. 33.

¹² *Id.*, Exhibit A.

¹³ [MPSC Staff Comments on Consumers Energy Company's EDIIP](#) in MPSC Case No. U-20147. February 16, 2024.

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DSP “complied with the September 8 order and the additional directives from the settlement agreement in Case No. U-21224”, while also noting that “Consumers’ spending demonstrates a large increase in capital expenditures and that this spending continues to increase each year.”¹⁴

Q. How has the Company presented its distribution system planning in this case?

A. The Company filed an amended version of the 2023 DSP as Exhibit No. A-129 (MPK-19) in this case in its entirety.

Q. What changes has the Company made to its DSP in Exhibit No. A-129 (MPK-19) compared to the 2023 DSP filed in U-20147?

A. Per Company witness Michael P. Kelly;¹⁵

“[T]he Company has made minor amendments to the 2023 Reliability Roadmap. These amendments primarily concern updating information to reflect another year of actual historical reliability data, and to extend projected investments by another year into the future. Some content has also been revised to reflect issues highlighted by intervenors in Case No. U-21585, or raised by intervenors in other regulatory areas, particularly in the Company’s third-party distribution system audit conducted in Case No. U-21305.”

Staff notes that the Company included, within Company witness Kelly’s testimony, sections of discussion that was filed previously with the 2023 DSP in MPSC Case No. U-20147, ostensibly to explain the purpose and findings of the prior 2023 DSP.

Q. What filing guidance was provided to the Company regarding amendments to DSPs?

A. On July 10th, 2025, the Commission issued an order approving Staff’s proposed guidance with modifications for future distribution plans, notably after this case was filed. The

¹⁴ [September 26, 2024 Commission Order](#) in MPSC Case No. U-20147, p. 142.

¹⁵ Prefiled Direct Testimony of Company witness Kelly, MPSC Case No. U-21870, p. 17.

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1 Company was a participating party in the engagement efforts held by Staff to develop those
2 guidelines and filed comments on the docket.

3 Q. How does the guidance differ from the Company's distribution planning efforts in this
4 case?

5 A. The guidelines, attached as Exhibit A to that order, informs the Company in Section VI (a)
6 and (b) that it may submit a revised DSP within a rate proceeding under two circumstances
7 - 1) significant misalignments between spend categories/allocations following changes in
8 investment strategy or 2) differences between the DSP and the rate case that the utility
9 judges to be significant. As seen in Company witness Kelly's discussion cited above, this
10 is not the situation in the refiled DSP as these are "minor amendments." While Staff
11 believes the Company was following the best guidance it had at the time for documenting
12 changes in its DSP investment strategy, it should also be noted that the refiled document
13 does not align with the intent of the guidelines and Commission order. The Commission
14 provided additional context in its order by defining "significant" under Section VI as
15 "including areas within a utility's DSP where strategies have changed, where spending
16 levels and/or timing for investments have materially changed, and/or where whole new
17 investment categories are included and discussed" and "foresees as being a rarity as
18 opposed to the normal course."¹⁶ Further, the Commission warns against misuse of the
19 supplemental rate case filing by stating it should "not be used as an avenue for utilities to
20 introduce new or unvetted investment strategies to achieve a desired outcome or spend
21 approval in the short-term through the present rate case." Small considerations, such as the
22 incorporation of previously discussed intervenor feedback and the addition of another

¹⁶ July 10, 2025 Order in MPSC Case No. U-20147, pp. 20-21.

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historical year to projections, are not considered as “significant” justification to refile. The Company is due to file its next DSP in 2027.

Q. Are there other changes between the 2023 DSP and this case that Staff wishes to address?

A. Yes. Staff notes that, within the Company’s exhibits and proceedings in this case, many projects, programs, and subprograms have changed names and contents. These changes were not always documented and made Staff’s comparison between the two documents difficult. In addition, because of the changes documented by Company witness Kelly, many capital costs have changed between the 2023 DSP and the current case. While Staff does not oppose the content of these changes necessarily and acknowledges that all plans and forecasts are subject to change, the recategorization of these changes between the 2023 DSP and the current rate case makes these investments very difficult to track between plans and rate cases.

Q. Please provide examples of this misalignment between the DSP and the rate case.

A. As an example, the automatic transfer recloser (ATR) loop program between the Company’s 2023 DSP (and, as such, its revised DSP exhibit in this case) and the rate case. ATR devices, put simply, help automate load transfer of customers in an outage situation; Consumers has been deploying these devices in loop schemes to both avoid customer outages and improve distribution system automation. In the revised DSP of this case, the ATR loops are included as a resiliency investment under the “Resilience” category.¹⁷ In the rate case, however, the ATR loops are a part of the LVD Lines Reliability subprogram under the “Reliability” category.¹⁸ Associated expenses are listed as the “Automation –

¹⁷ Prefiled Exhibits of Company witness Kelly, MPSC Case No. U-21870, Exhibit A-129 (MPK-19), p. 81.

¹⁸ Prefiled Direct Testimony of Company witness Partlan, MPSC Case No. U-21870, p. 44.

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1 ATR Loops” category in the Bridge Period LVD Project List.¹⁹ Providing additional
 2 confusion, Company witness Scott A. McPhail discusses ATR deployment as part of
 3 several projects in the Grid Automation category, such as the Peer-to-Peer project²⁰ and
 4 the FLISR project.²¹ The Grid Automation category, which the Company previously called
 5 Grid Modernization, handles much of the Company’s automation initiatives and is separate
 6 from its LVD Lines Reliability subprogram. The Company does not clearly delineate
 7 between these various uses of ATR automation in the rate case and the DSP.

8 As a second example, between Case No. U-21585 and U-21870, the “HVD Lines
 9 and Substation Rehabilitation” sub-program became the new “Transformer Bank
 10 Replacements and Substation Rebuilds” sub-program or was merged into the existing
 11 “HVD Lines Reliability” subprogram. Company witness Megan L. Hayward provides
 12 some breakdown between the historical spending category and the new category in her
 13 Figures 12, 34, and 35, and a paragraph documenting the change in her testimony.²² Two
 14 of the previous categories under that sub-program were moved and merged into other
 15 programs under the “HVD Lines Reliability” subprogram, while one was simply moved.
 16 Another category was discontinued (“Miscellaneous Other Requirements”) and the final
 17 subdivided and separated into three other categories under “Transformer Bank
 18 Replacements and Substation Rebuilds”. While an explanation was provided by Company
 19 witness Hayward from Case No. U-21585 and Case No. U-21870 to track where those
 20 expense changes, no walkthrough or explanation was attempted by the Company to walk

¹⁹ Prefiled Exhibits of Company witness Partlan, MPSC Case No. U-21870, Exhibit A-166 (JMP-1), p. 14.

²⁰ Prefiled Direct Testimony of Company witness McPhail, MPSC Case No. U-21870, p. 33.

²¹ *Id.*, at, pp. 67-69.

²² Prefiled Direct Testimony of Company witness Hayward, MPSC Case No. U-21870, p. 31.

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those same expense category changes between Case No. U-21870 and the DSP the Company filed in Case No. U-20147 in 2023.

These are meant as illustrative examples of the drastic changes between the 2023 DSP and the current rate case, and do not encompass every expense or category the Staff has had difficulty tracking between the documents.

Q. Has the Commission previously provided guidance on this topic?

A. Yes. In the Company's previous rate case, MPSC Docket No. U-21585, the Commission notes several times in its March 21, 2025 Order that "recategorizing or shifting of expenditures from one subprogram to another may lend confusion to the process of identifying historical costs and benefits as well as justifying projected expenditures"²³ and that "simply relabeling or recategorizing capital expenditures from one program or tracking method to another does not provide sufficient evidence to demonstrate the reasonableness and prudence of costs nor the benefits of program expenditures."²⁴ The order asks the Company to be clear and do its due diligence to avoid any confusion when discussing historical and planned investments. Given that DSPs discuss planned investments, there is no exception for alignment between the DSP and rate case categories. Staff notes the Commission disallowed several expenses on such reasoning in that case, and stated that:

*"...the Commission expects to see additional detail in future electric rate cases regarding line items that have been recategorized, the past spending levels for those line items, how historical spending for any relabeled line items compares to proposed expenditures, and clarity on how these investments deliver value for the company's customers."*²⁵

²³ March 21, 2025 Order in U-21585, p. 102.

²⁴ *Id.*, at, p. 62.

²⁵ *Id.*, at, p. 63.

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Further, the Commission's July 10, 2025 order in U-20147 when describing alignment between the DSP and rate case states:

*"DSPs are meant to be fully vetted, executable plans that flow directly into a utility's rate case request... and alignment between the two filings is necessary for the Commission's accurate evaluation."*²⁶

and:

*"DSP spending classifications (such as programs, subprograms, categories) shall be aligned with such classifications within the utility's rate case, with variations explained in detail."*²⁷

Q. Is the Staff recommending any disallowances in this case due to misalignment between the DSP and rate case?

A. No. The current filing guidelines were approved by the Commission after the Company submitted this rate case. Should the Commission accept Staff's recommendation, only future rate case costs would be impacted.

Q. What does Staff recommend in regard to future case alignment with DSPs?

A. Distribution system planning efforts and rate case proceedings are inherently linked, as both the Commission and the Company have acknowledged in the past. Therefore, reasonable and prudent costs should be categorized and similarly trackable between any DSP submitted by the Company and any rate case which uses such DSP to justify cost recovery. Staff recommends the Commission recognize such and consider that any costs in future cases that are unable to be reconciled or tracked between the planning efforts and the rate case be disallowed.

²⁶ July 10, 2025 Order in MPSC Case No. U-20147, p. 21.

²⁷ *Id.*, Exhibit A, p. 3.

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In addition, Staff recommends the Commission direct the Company to reevaluate its supplemental rate case filings for future rate cases to align with the July 10, 2025 order in U-20147.

Coordination with MPSC Case No. U-21305

Q. What conclusions from the Consumers Liberty Consulting Group (Liberty) Audit were adopted by the Commission in its June 12, 2025 Order in MPSC Case No. U-21305 related to future System Average Interruption Duration Index (SAIDI) performance?

A. The Chapter II, Recommendation 1 of the Consumers Liberty Audit Report, states the Company should “[r]estate EDIIP reliability and safety program, measure, and activity scopes to optimize scope and expenditures assuming an extended period to reach second quarter SAIDI performance.” which leads to Conclusion 1 in that same report that “[t]he goal of reaching essentially the median industry level for SAIDI performance is very aggressive, given the massive efforts and large expenditure increases needed to meet it; meeting it does not appear highly likely and efforts to pursue it may lead to more costly programs, initiatives, and activities.”²⁸ In that case, the Company commits to an analysis of slower investment paces in this current case. The Commission ordered that it will “continue to evaluate the company’s plans going forward, including the evaluation of an extended timeframe from seven to ten years coupled with evidence supporting the appropriate mix of projected capital and O&M spending to meet the goal in a cost-effective manner.”²⁹ Staff notes that the cited order was issued three months after this current case was filed and thus refers to the Company’s next rate case.

²⁸ Final Report Utility Distribution Audit of Consumers Energy Part Two, Case No. U-21305, September 23, 2024, pp. 58-59.

²⁹ June 12, 2025 Order in U-21305, p. 18.

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1 Q. Please summarize the arguments on SAIDI performance related to the discussions within
2 MPSC Case No. U-21305.

3 A. The Company, as in its 2023 DSP plan submitted to MPSC Case No. U-20147, projects a
4 five-year “glidepath” of desired SAIDI performance based on its projections. It also
5 presents, per the U-21305 order state above, alternative seven-year and ten-year
6 “glidepath” projections.³⁰

7 Additionally, as discussed by many parties including the Company in MPSC
8 Docket No. U-21305, Consumers contests the statement from the Liberty audit that it has
9 not meaningfully improved its reliability over the past decade. This is acknowledged and
10 then further argued by the Company in Company witness Kelly’s testimony.³¹ The
11 Company also provides Figure 6 to illustrate its improvement in SAIDI performance since
12 2014,³² which I have copied here for simplicity.

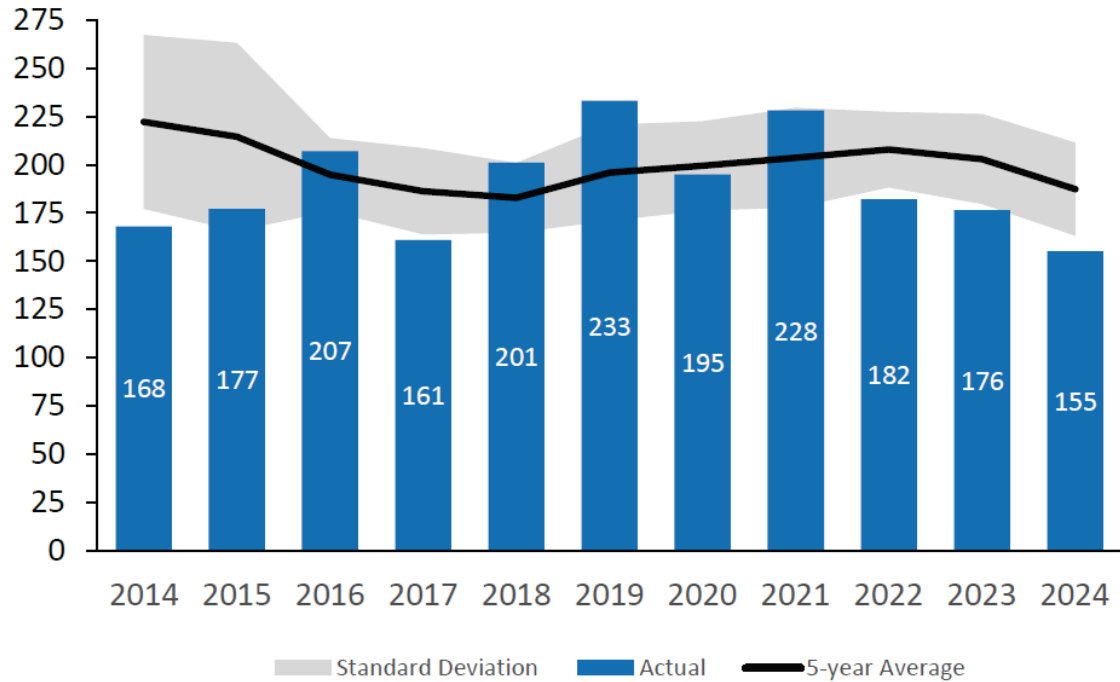
³⁰ Prefiled Direct Testimony of Company witness Kelly, MPSC Case No. U-21870, Figure 19, p. 40.

³¹ *Id.*, at, pp. 24-25.

³² *Id.*, at, p. 26.

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FIGURE 6
SAIDI PERFORMANCE COMPARED TO STANDARD DEVIATION (2014-2024)



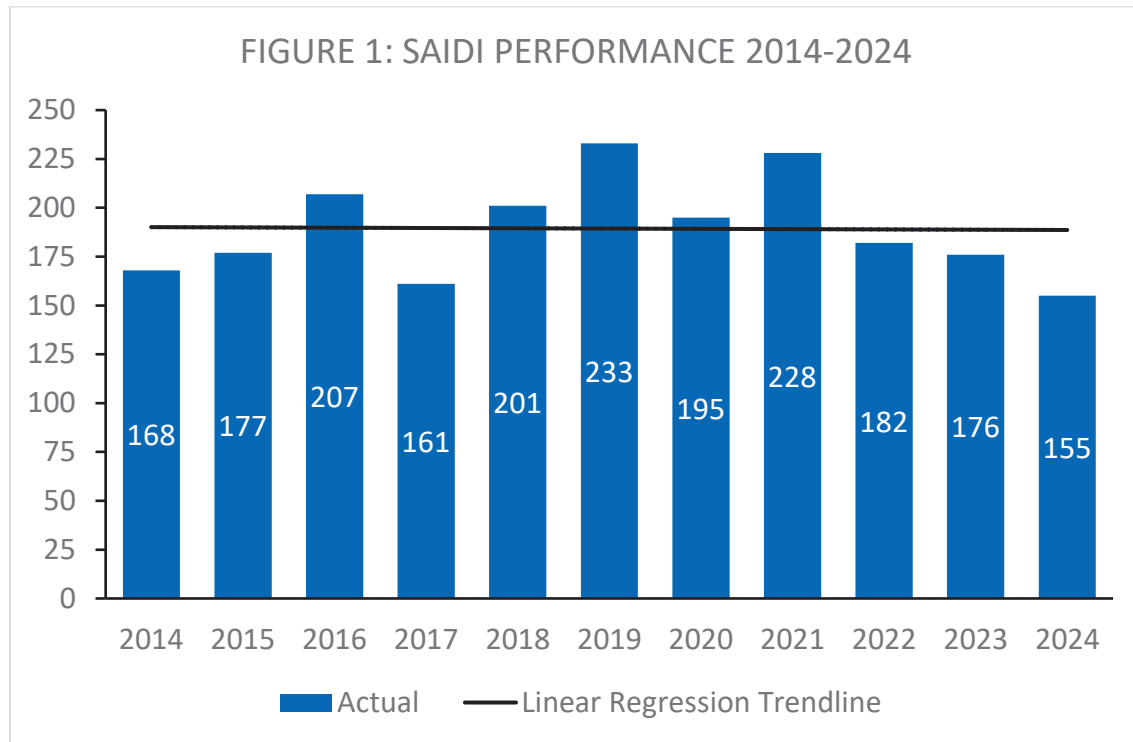
The Company then argues that its SAIDI has improved in the three most recent years. It also argues that a five-year average is most appropriate, as it would “limit annual variability.”³³

Q. What concerns does Staff have with the Company’s Figure 6?

A. The graph is misleading. The Company uses a rolling five-year average to create the illusion of a declining trendline over the entire period shown in Figure 6. Using a rolling average line can obscure other trends and as such, the line lags the current data. Staff used the same data as the Company presented in Figure 6 and ran a typical linear regression trendline to better demonstrate the movement of SAIDI performance in the past decade, using the entirety of the data instead of a five-year average. This is presented as Figure 1.

³³ Prefiled Direct Testimony of Company witness Kelly, MPSC Case No. U-21870, Figure 19, p. 25.

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The incredibly slight slope of the trendline is not statistically significant, as demonstrated in the further data analysis in Staff Exhibit S-19.1. In using the full decade of data presented in the Company's Figure 6, there is a marked lack of reliability improvement. In the MPSC Case No. U-21305 proceedings, other intervenors and Liberty itself argue that the past decade of additional data contains important context. The additional half-decade of data also meets the Company's desire to limit annual variability, one of the main reasons it consistently argues for a five-year average usage. Staff opines that the ten-year range, therefore, provides an even more stable figure when considering annual variability when presented with this data.

Q. Are there considerations as to why the Company would assert that a five-year data range is most appropriate?

A. Yes. Within the aforementioned discussions in Docket No. U-20147 around appropriate distribution guidelines, Staff advocated previously for five years of historical data. The

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1 Company also may have internal standards for five years of data. Considering the results
2 of the Liberty audit discussions and the data analysis presented above, the Staff postulates
3 that perhaps additional data would be more appropriate context.

4 In addition, Staff postulates that the few worst years of SAIDI performance between
5 2019 and 2021 make the recent five-year trends appear as if the Company is consistently
6 improving SAIDI performance over the long-term. When additional historical data is
7 considered, as in Staff's Figure 1 and argued in the Liberty audit, the downward trend is
8 mitigated. While 2024 may be the best year in SAIDI performance so far, the second-best
9 year is 2017, while the third best is 2014, both of which are not included in the five-year
10 average the Company examines. The Company confirmed through discovery that the
11 model it is using to project potential SAIDI improvements only considers the prior five
12 years of historical data, and not the larger decade trend presented by Liberty.³⁴

13 Q. How does the Company project SAIDI improvements?

14 A. The Company uses an internal model "to project improvements to SAIDI reliabilities
15 versus historical trendlines between SAIDI and spend in areas such as line clearing, capital
16 investments in key areas, and certain CAIDI improvements."³⁵ It is through this model that
17 the Company created its five-year, seven-year, and ten-year improvement projections.

18 Q. Do the seven-year and ten-year projected "glidepaths" meet the requirements set by the
19 Commission Order in Case No. U-21305?

20 A. No, for several reasons. First, the Company did not meaningfully examine an extended
21 period to reach second quartile SAIDI performance. It appears the Company simply ran

³⁴ Staff Exhibit No. S-19.0, ST-CE-0589, p. 8.

³⁵ Prefiled Direct Testimony of Company witness Kelly, MPSC Case No. U-21870, p. 28.

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1 its model for longer periods. In discovery, when questioned how the “glidepath”
2 corresponds to actual improvement, the Company responds that they cannot produce error
3 margins with confidence due to a limited sample size.³⁶ It also states within testimony that
4 its 2024 performance was accurate to the model, while confirming it was outside of a
5 standard deviation in the model. It also admits to a large variance in the 2021 data.³⁷ In
6 another discovery, the Company states that accuracy of the model is limited due to “the
7 unknown impacts on the system of day-to-day weather that would not occur for more than
8 five years from today.”³⁸ The Company’s model, historically, has been unable to predict
9 two of the previous four years (for better or for worse reliability) and cannot guarantee
10 accuracy nor quantify the error of the model.

11 The Company’s modeling approach is in good faith; however, the approach above
12 does not appear to properly fit the data. The model is too nascent to rely on, as discussed
13 obliquely by the Company above. In addition, while the model does project a future SAIDI
14 improvement, the model is based on historical performance of SAIDI coupled with
15 expenses used to reach that level of performance. As demonstrated above in Figure 1, the
16 SAIDI performance of the Company has not meaningfully changed in the past decade.
17 SAIDI performance is also highly dependent on weather. Michigan weather is expected to
18 become more severe over the coming years,³⁹ which five years of historical data will not
19 meaningfully capture in a historical-looking model. Improvements the Company has seen
20 in SAIDI with one investment in the model may not arrive in different weather or may be
21 amplified in a storm year. The Company has included projections of this increasing

³⁶ Staff Exhibit No. S-19.0, ST-CE-0197, p. 3.

³⁷ Prefiled Direct Testimony of Company witness Kelly, MPSC Case No. U-21870, p. 29.

³⁸ Staff Exhibit No. S-19.0, AG-CE-0423, p. 6.

³⁹ Prefiled Direct Testimony of Company witness Kelly, MPSC Case No. U-21870, p. 19.

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1 severity in other parts of its scenario analysis. The model, however, does not appear to be
2 weather normalized, though, as stated above, the heavy reliance of SAIDI on the weather
3 would make such normalization difficult. Basing all potential SAIDI investments on five
4 years of historical data, which does not capture the trends shown in Figure 1, creates a
5 flawed model and approach.

6 Second, there was no attempt by the Company to show how this extended period
7 could contribute to cost effectiveness, affordability, or decreased rate impacts. It states in
8 discovery that “[s]uch quantitative analysis was not part of the recommendation by the
9 Liberty Consulting Group”⁴⁰ which, while true, ignores the Commission’s statement in its
10 order regarding approaching SAIDI with a “cost effective manner.” The Commission
11 continues to examine all possibilities to address affordability and rate impact in Michigan,
12 and Staff would be interested to see how an extended SAIDI timeline could contribute to
13 those goals. The Company states in discovery that “[t]he alternative glidepaths may result
14 in *cheaper* outcomes for customers *today*, but that does not mean that these outcomes are
15 the most cost effective for customers in the longer term [emphasis original]”⁴¹ yet has
16 provided no data or analysis to whether a quicker, five year “glidepath” *would* be the most
17 cost effective for customers in the long run. As stated above, the Company cannot
18 guarantee accuracy of its SAIDI model, nor model error on it, nor even reliably predict
19 what a year’s reliability will be with it. The question of cost effectiveness has not been
20 appropriately addressed by the Company in these extended “glidepaths” in this case.

⁴⁰ Staff Exhibit No. S-19.0, ST-CE-0506, p. 7.

⁴¹ *Id.*

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PART II

1 Q. What reasons does the Company give for its continued commitment to the five-year
2 “glidepath”?

3 A. The Company states that other strategies would include “unacceptable outcomes”,
4 including a reduction or elimination of ATR loops, zonal health investments, and the
5 Company’s diverse portfolio of reliability investments.⁴² Company witness Kelly also
6 states that “[t]he Company must be allowed to invest at a level that will allow the Company
7 to avoid financial penalties established by the Commission.”⁴³

8 Q. Does Staff agree with these statements?

9 A. Not necessarily. The Commission has adopted certain Liberty recommendations in MPSC
10 Docket No. U-21305, which highlight areas where the Company may slow its investments,
11 but has not ordered such directly. Rather, the Commission asks the Company to analyze
12 and share the tradeoffs with other potential capital and O&M program spending and
13 support why its decisions are reasonable. If certain programs are unacceptable to cut for
14 the Company, then it should explain why it will not cut them. The Company, as outlined
15 above, has not meaningfully demonstrated in this case what programs could be reduced,
16 rearranged, extended, or cut. Staff acknowledges that a slower investment pace may
17 require potential program cuts in certain areas, but the Company cannot make an internal
18 management decision on said cuts and then accuse the Commission of forcing it to remove
19 programs.

⁴² Staff Exhibit S-19.0, ST-CE-0196, pp. 1-2.

⁴³ Prefiled Direct Testimony of Company witness Kelly, MPSC Case No. U-21870, p. 45.

DIRECT TESTIMONY OF ANNA N. N. SCHILLER
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PART II

Staff also takes issue with the Company's insistence that the Commission must allow recovery of investments to avoid penalties the Commission itself has set. The Company presumes much by this statement.

Q. To what financial penalty is the Company referring to?

A. The Commission is in the process of establishing performance-based ratemaking procedures in MPSC Case Nos. U-21400 and U-21911. These include financial incentives and disincentives based on the Company's reliability performance, including SAIDI performance. The Company asserts that, out of the three "glidepaths" it examined, only the five-year "glidepath" would be able to gain one of the proposed draft incentives by 2030.⁴⁴ Staff notes that no "glidepath" shown on the Company's projections would result in a financial penalty.

Q. Is the Commission required to allow the Company to "invest at a level that will allow the Company to avoid financial penalties established by the Commission," or, as may be the case, allow the Company to earn a financial incentive established by the Commission?

A. No. The Commission's duty is "to serve the public by ensuring safe, reliable, and accessible energy and telecommunications services at reasonable rates."⁴⁵ Removal of financial penalties or the acquisition of incentives may be a priority of Consumers, but that does not mean that recovery of related costs is inherently reasonable.

Q. What does Staff recommend regarding the Company's SAIDI projections?

A. Staff would ask that the Commission and the Company give more thought to these potential extended timelines for SAIDI improvements in the Company's next rate case, as it

⁴⁴ Prefiled Direct Testimony of Company witness Kelly, MPSC Case No. U-21870, Figure 20, p. 44.

⁴⁵ State of Michigan, Michigan Public Service Commission, "[About the MPSC: Mission Statement](#)", retrieved September 23, 2025.

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1 committed to in the U-21305 Order. It would recommend the Commission closely
2 scrutinize the models the Company will use to project such investments and compare it to
3 the Company's history appropriately. To that end, the Commission should not allow any
4 spend in future rate cases that is based solely on avoiding financial penalties set by the
5 Commission; while the rapid investment in SAIDI could potentially provide reliability
6 benefits to customers, the Company has yet to prove it is reasonable from a cost-effective
7 standpoint.

8 In addition, the Staff recommends the Commission look into extending the
9 historical data requirements currently presented in the guidelines from the July 10th order
10 in U-20147. The Company and Liberty demonstrate here that more data and a longer
11 historical look could be beneficial to projections of future improvements in that context as
12 well. The current guidelines list a five-year historical data review, as available: Staff would
13 recommend this be extended to ten years, as available, should the Commission chose to
14 revise the guidelines.

15 Q. Does Staff have further discussion regarding the outcomes of recent orders in MPSC
16 Docket U-21305?

17 A. Yes. Staff witness Jessica Duell discusses other influences MPSC Docket U-21305 has
18 had on this rate case, including the Company's commitment to expedited tree trimming
19 cycles.

20 **Recommendations**

21 Q. Please summarize your recommendations below.

22 A. Staff recommends the Commission:

DIRECT TESTIMONY OF ANNA N. N. SCHILLER**CASE NUMBER U-21870****PART II**

1. Request the Company to provide a thorough breakdown of the inspection associated costs applied across all capital programs/subprograms, support why the costs are appropriately classified as capital instead of O&M with reference(s) to accounting guidance, and amend the classification of these expenditures in the Company's next rate case, where necessary, based on the analysis. In addition, the Commission should require the Company to explain why section 2 under the Operating Expense of USOA is not appropriate for the inspection-related costs of the LVD Lines Demand Failures subprogram and why section 3 under the Electric Plant of USOA is appropriate.
2. Require costs to be categorized and similarly trackable between any submitted DSP and any rate case which uses such DSP to justify cost recovery to prove prudence and reasonableness of such costs.
3. Require a comprehensible walkthrough of any expense programs, subprograms, and/or categories that have varied between the prior submitted DSP and the ongoing rate proceedings as an exhibit within that rate proceeding.
4. Consider revising the DSP guidelines presented in the July 10th order in Case No. U-20147 to include, where applicable, ten-years of historical reliability data, as available.
5. Require a method other than the SAIDI performance model used in this case to examine fully potential extended timelines for SAIDI improvements in the Company's next rate case to be considered reasonable in reference to the June 12, 2025 order in Case No. U-21305.
6. Require the Company to assess the cost effectiveness, affordability, and potential rate impact of any SAIDI performance forecast related to the U-21305 order.

DIRECT TESTIMONY OF ANNA N. N. SCHILLER**CASE NUMBER U-21870****PART II**

1 | 7. Establish that any expenses in future rate cases based solely on avoiding financial
2 | penalties or gaining a financial incentive set by the Commission as imprudent.

3 | Q. Does this conclude your testimony?

4 | A. Yes, it does.

1 MR. SONNEVELDT: Next, Your Honor, Staff moves
2 to bind in the direct testimony of Hunter Hansen. His
3 testimony consists of a cover sheet and seven pages of
4 questions and answers. He also sponsors exhibits S-12.0
5 through S-12.3.

6 JUDGE THOITS: Are there any objections to the
7 admission of this testimony or these exhibits?

8 Hearing none. The direct testimony of Hunter
9 Hansen is bound into the record, and Exhibits S-12.0
10 through S-12.3 are admitted.

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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 generation and distribution of)
electricity and for other relief.)
_____)

Case No. U-21870

QUALIFICATIONS AND DIRECT TESTIMONY OF
HUNTER HANSEN
MICHIGAN PUBLIC SERVICE COMMISSION

09/30/2025

QUALIFICATIONS OF HUNTER HANSEN
CASE NUMBER U-21870
PART I

1 Q. Please state your full name and business address for the record.

2 A. My name is Hunter Hansen (he/him), and my business address is 7109 W.
3 Saginaw Highway, Lansing, MI 48917.

4 Q. By whom are you employed and in what capacity?

5 A. I am employed by the Michigan Public Service Commission (MPSC or
6 Commission) as a Public Utilities Engineer in the Data Access, Privacy & IT
7 Section of the Customer Assistance Division.

8 Q. Please describe your educational background.

9 A. I earned a bachelor's degree in mechanical engineering from Michigan State
10 University in 2022.

11 Q. What is your professional background?

12 A. I began working for the MPSC in the Data Access, Privacy & IT Section as a
13 Public Utilities Engineer in 2023. I am responsible for analyzing rate case
14 recovery requests relating to Advanced Metering Infrastructure (AMI), Meter
15 Reading, and Information Technology (IT).
16 Prior to my current position, I worked as a research assistant at Michigan State
17 University in the Department of Biosystems and Agricultural Engineering. My
18 job duties included the assembly, installation, and maintenance of devices that
19 collected data on farm fields throughout Michigan. I also analyzed the data
20 collected from these devices. I also assisted with designing and carrying out
21 various experiments and the writing of research papers on the outcomes of these
22 experiments.

QUALIFICATIONS OF HUNTER HANSEN
CASE NUMBER U-21870
PART I

1 Q. Have you received any work-related training since your employment with the
2 MPSC?

3 A. Yes, in January of 2024 I attended the National Association of Regulatory Utility
4 Commissioners' Basics of Utility Accounting and Ratemaking course. I also
5 attended Michigan State Universities Institute of public Utilities Annual
6 Regulatory Studies Program fundamentals course in August of 2024.

7 Q. Have you previously filed testimony before the Commission?

8 A. Yes, I have filed testimony in Case No. U-21540, Michigan Gas Utility
9 Corporation's gas rate case, Case No. U-21555, Upper Peninsula Power
10 Company's electric rate case, Case No. U-21585, Consumers Energy Company's
11 electric rate case, and in Case No. U-21860, DTE Electric Company's electric rate
12 case.

DIRECT TESTIMONY OF HUNTER HANSEN
CASE NUMBER U-21870
Part II

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

2 A. The purpose of my testimony is to present Michigan Public Service Commission
3 Staff's (Staff) recommendations regarding Consumers Energy Company's
4 (Consumers or the Company) request for recovery of capital expenditures for
5 Facilities and Shared Services expenses located on Company Exhibit A-102
6 (QAG-3). I will also present Staff's recommendation to the Commission
7 regarding the Company's proposed updates to the advanced metering
8 infrastructure (AMI) opt-out charges.

9 Q. Are you sponsoring any exhibits in this proceeding?

10 A. Yes, I will be sponsoring the following exhibits:
11 Exhibit S-12.0 Supporting Audit Responses
12 Exhibit S-12.1 Facilities & Shared Devices Disallowance Calculation
13 Exhibit S-12.2 AMI Opt-Out Upfront Charge Breakdown
14 Exhibit S-12.3 AMI Opt-Out Monthly Charge Breakdown

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

16 A. Yes.

17 **Facilities and Shared Services**

18 Q. What 'Facilities and Shared Services' expenditures have been included in this
19 case?

20 A. Facilities and Shared Services expenditures are located on Company Exhibit A-
21 102 (QAG-3). In addition to other expenditures, this exhibit includes costs for two
22 categories: Other Equipment and Emergent Repairs. For Other Equipment, the
23 Company is requesting \$357,000 in the historic year ending 12/31/2024, \$838,000

DIRECT TESTIMONY OF HUNTER HANSEN
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Part II

1 in the projected bridge period of 16 months ending 4/30/2026, and \$670,000 in
2 the projected test year ending 4/30/2027. For Emergent Repairs, the Company is
3 requesting \$1,010,000 in the historic year ending 12/31/2024, \$1,344,000 in the
4 projected bridge period of 16 months ending 4/30/2026, and \$2,706,000 in the
5 projected test year ending 4/30/2027.

6 Q. What is Staff's recommended adjustment for Other Equipment and Emergent
7 Repairs expenditures?

8 A. Staff's recommended adjustment for Other Equipment is a disallowance of
9 \$98,200 in the projected test year ending 04/30/2027 (Exhibit S-12.1). Staff's
10 recommended adjustment for Emergent Repairs is a disallowance of \$948,800 in
11 the projected test year ending 04/30/2027 (Exhibit S-12.1).

12 Q. Why is Staff recommending these adjustments?

13 A. In audit, Staff asked the Company to provide any expenditures in this case that
14 represent placeholder or blanket work orders, or are set aside for contingency,
15 risk, unforeseen events, or emergent work. The Company provided the Other
16 Equipment and Emergent Repairs line items as falling under these categories
17 (Exhibit S-12.0, p. 1). For both line items, the Company stated that spend in each
18 category is maintained at or below the 5-year average historic spend (Exhibit S-
19 12.0, p. 1). Staff then asked the Company to provide the 5-year historic spend for
20 each line item in its next round of audit, which the Company provided (Exhibit S-
21 12.0, p. 2). For both the Other Equipment line item and the Emergent Repairs
22 line item, the 5-year historic average spend is less than what the Company is
23 requesting recovery for in the projected test year (Exhibit S-12.1). The Company

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1 did not provide any evidence for why it should receive more in the projected test
2 year than what it has spent on average in the last five years. Staff's proposed
3 disallowance for both line items is the difference between the Company's
4 projected test year request and the 5-year historic average. The Commission
5 should adopt Staff's proposed disallowances of \$98,200 in the projected test year
6 ending 04/30/2027 for the Other Equipment line item and \$948,800 in the
7 projected test year ending 04/30/2027 for the Emergent Repairs line item.

8 **AMI Opt-Out Charges**

9 Q. What has the Company included regarding AMI opt-out charges in this
10 proceeding?

11 A. Company Witness Kelly describes the Company's updated AMI opt-out charges
12 on pages 188-191 of his direct testimony. The Company is proposing to change
13 the upfront charge for the meter installation from \$123.91 to \$216.22 and the
14 monthly charge from \$3.00 to \$3.09.

15 Q. Why did the Company propose updated charges?

16 A. The Company is proposing these updated charges due to the Commission order in
17 Case No. U-21585 in which the Commission ordered the Company to re-evaluate
18 the charges to ensure alignment with cost-of-service and to include the updated
19 charges in its next rate case.¹

20 Q. What is Staff's recommendation regarding the proposed upfront charge?

¹ MPSC Case No. U-21585, 3/21/2025 Order, p 98.

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1 A. Company Witness Kelly's testimony describes each of the components that go
2 into the cost of the upfront charge on page 189 of his testimony and the cost
3 breakdown for each component is shown on Exhibit A-136 (MPK-26). Two of the
4 components are described as reflecting the costs associated with swapping out a
5 standard AMI meter for a non-transmitting meter, but one of these components
6 accounts for \$45 of the upfront cost while the other accounts for \$93. Believing
7 that these costs may be duplicative of one another, Staff asked about these costs in
8 audit. The Company explained that the incorrect basis was used for the \$93 cost
9 and that it should be equal to the \$45 cost, since it is reflective of the potential to
10 replace a non-transmitting meter back to a standard AMI meter in the future
11 (Exhibit S-12.0, p. 3). This changes the proposed upfront charge from \$216.22 to
12 \$168.07 (Exhibit S-12.2). The Commission should adopt this updated opt-out
13 upfront charge of \$168.07.

14 Q. What is Staff's recommendation regarding the proposed monthly charge?

15 A. In audit, Staff asked for a breakdown of each of the costs shown on Company
16 Exhibit A-136 (MPK-26) (Exhibit S-12.0, p. 4). The Company provided a
17 breakdown; however, Staff has concerns with the basis for the costs (Exhibit S-
18 12.3). The first section, lines 1-6, shows the cost of all non-AMI reads, the
19 number of manual gas reads, the number of manual electric reads, and the number
20 of automated meter reading (AMR) gas reads. The cost is then divided by the total
21 number of reads to arrive at the average read cost. The vast majority of the reads
22 are AMR gas reads, 13.9 million out of 14.2 million, with only 133,000 manual
23 electric reads. Therefore, Staff believes that this cost is far more reflective of the

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1 cost of AMR gas reads than it is of AMI opt-out reads. Staff asked the Company
2 to provide the cost to read the Company's non-transmitting meters to which the
3 Company replied that it does not track the costs to read non-transmitting meters
4 separately from total meter reading costs (Exhibit S-12.0, p. 5). As it is currently
5 calculated, Staff finds that the proposed monthly charge is not reflective of cost-
6 of-service and should be rejected by the Commission. Staff recommends that the
7 Commission require the Company to begin tracking the costs of reading opt out
8 AMI meters so that the Company can propose an updated, cost-of-service based,
9 monthly charge in a future proceeding.

10 Q. Please provide a summary of your testimony.

11 A. My testimony presents Staff's recommendation to the Commission to make a
12 disallowance to the Other Equipment and Emergent Repairs line items due to the
13 Company's request in the projected test year being more than the 5-year average
14 historic spend for the same line items. My testimony also presents Staff's
15 recommendation to the Commission to reject the Company's proposed AMI opt-
16 out upfront charge of \$216.22 but to adopt the updated upfront charge of \$168.07.
17 Lastly, my testimony recommends that the Commission reject the Company's
18 proposed AMI opt-out monthly charge because it is not cost-of-service based and
19 to require the Company to begin tracking the cost of reading the Company's non-
20 transmitting meters so that the monthly charge can be updated based on cost-of-
21 service in a future proceeding.

22 Q. Does this conclude your direct testimony?

23 A. Yes.

1 MR. SONNVELDT: Next, Your Honor, Staff moves to
2 binding the direct testimony of Brittany Klocke. Her
3 direct testimony consists of a cover sheet and 19 pages of
4 questions and answers. She also sponsors Exhibits S-10.1
5 through S-10.28.

6 JUDGE THOITS: Are there any objections to the
7 admission of this testimony or these exhibits?

8 Hearing none. The direct testimony of Brittany
9 Klocke is bound into the record, and Exhibits S-10.1
10 through S-10.28 are admitted.

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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 increases its rates for the generation of electricity and for other relief.	)))))))	Case No. U-21870
_____	)	

QUALIFICATIONS AND DIRECT TESTIMONY OF
BRITTNEY KLOCKE
MICHIGAN PUBLIC SERVICE COMMISSION

September 30, 2025

QUALIFICATIONS OF BRITTNEY KLOCKE
CASE NUMBER U-21870
PART I

1 Q. Please state your full name and business address.

2 A. My name is Brittney Klocke and my business address 7109 West Saginaw
3 Highway, Lansing, MI 48917.

4 Q. By whom are you employed and in what capacity?

5 A. I am employed by the Michigan Public Service Commission (MPSC or
6 Commission) as a Senior Analyst in the Data Access, Privacy and IT (DAPIT)
7 Section of the Customer Assistance Division (CAD).

8 Q. Please describe your educational background.

9 A. I earned a Bachelor of Arts degree in Political Science from Miami University in
10 2006 and a Juris Doctor degree from Michigan State University College of Law in
11 2009.

12 Q. Please describe your professional experience.

13 A. I began my professional career with the State of Michigan in 2010, when I was
14 hired as an Eligibility Specialist with the Department of Health and Human
15 Services (DHHS). While with DHHS, I worked in a Specialized Medicaid Unit
16 that reviewed retroactive and opened ongoing Medicaid cases.
17 In 2011, I accepted a position with the Department of Treasury (Treasury) as a
18 Field Officer in the Collection Services Bureau. In that role, I was primarily
19 tasked with performing research and analysis assignments related to various tax
20 laws administered by Treasury. That entailed conducting field calls at businesses
21 all over Michigan to verify taxpayer compliance and registration status, as well as
22 identifying complex schemes related to tax avoidance and fraud.

QUALIFICATIONS OF BRITTNEY KLOCKE
CASE NUMBER U-21870
PART I

1 In July 2022, I accepted my current position with the MPSC. In this role, I
2 perform analysis of utilities' rate case recovery requests related to Customer
3 Experience and Information Technology (IT).

4 Q. Have you received any work-related training since your employment with the
5 MPSC?

6 A. Yes. I attended Michigan State University's Institute for Public Utilities' (IPU)
7 Annual Regulatory Studies Program in August of 2022. In September of 2022, I
8 attended IPU's Accounting & Ratemaking Course. In March of 2023, I attended
9 the National Association of Regulatory Utility Commissioners' Rate Case Basics
10 course.

11 Q. Have you previously filed testimony before the Commission?

12 A. Yes.

13 Q. Please list the cases in which you have filed testimony before the Commission.

14 A. • Case No. U-21308, the Consumers Energy gas case
15 • Case No. U-21297, the DTE electric case
16 • Case No. U-21389, the Consumers Energy electric case
17 • Case No. U-21461, the Indiana Michigan Power Company electric case
18 • Case No. U-21490, the Consumers Energy gas case
19 • Case No. U-21540, the Michigan Gas Utilities Corporation gas case
20 • Case No. U-21534, the DTE electric case
21 • Case No. U-21585, the Consumers Energy electric case
22 • Case No. U-21806, the Consumers Energy gas case
23 • Case No. U-21860, the DTE electric case

DIRECT TESTIMONY OF BRITTNEY KLOCKE
CASE NUMBER U-21870
PART II

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

2 A. The purpose of my testimony is to present MPSC Staff's (Staff) recommendations
3 regarding Consumers Energy Company's (CE or the Company) request for
4 recovery of proposed expenditures for Customer Information Technology (IT)
5 projects for the Customer Experience and Operations areas, as detailed in
6 Company Exhibits A-20 (SHB-5) CONF and A-12 (JRB-1), Schedule B-5.3.

7 Q. Are you sponsoring any exhibits in this proceeding?

8 A. Yes, I am sponsoring the following exhibits:

- 9 • S-10.1 – Audit Response U21870-SA-CE-081
- 10 • S-10.2 – Audit Response U21870-SA-CE-151_Baker_ATT_1
- 11 • S-10.3 – Audit Response U21870-SA-CE-198
- 12 • S-10.4 – Audit Response U21870-SA-CE-245
- 13 • S-10.5 – Audit Response U21870-SA-CE-241
- 14 • S-10.6 – Audit Response U21870-SA-CE-242
- 15 • S-10.7 – Audit Response U21870-SA-CE-207
- 16 • S-10.8 – Audit Response U21870-SA-CE-208
- 17 • S-10.9 – Audit Response U21870-SA-CE-210
- 18 • S-10.10 – Audit Response U21870-SA-CE-211
- 19 • S-10.11 – Audit Response U21870-SA-CE-196
- 20 • S-10.12 – Audit Response U21870-SA-CE-231
- 21 • S-10.13 – Audit Response U21870-SA-CE-232
- 22 • S-10.14 – Audit Response U21870-SA-CE-233
- 23 • S-10.15 – Audit Response U21870-SA-CE-234

DIRECT TESTIMONY OF BRITTNEY KLOCKE
CASE NUMBER U-21870
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1 • S-10.16 – Audit Response U21870-SA-CE-235

2 • S-10.17 – Audit Response U21870-SA-CE-236

3 • S-10.18 – Audit Response U21870-SA-CE-237

4 • S-10.19 – Audit Response U21870-SA-CE-205

5 • S-10.20 – Audit Response U21870-SA-CE-216

6 • S-10.21 – Audit Response U21870-SA-CE-217

7 • S-10.22 – Audit Response U21870-SA-CE-218

8 • S-10.23 – Audit Response U21870-SA-CE-219

9 • S-10.24 – Audit Response U21870-SA-CE-220

10 • S-10.25 – Audit Response U21870-SA-CE-223

11 • S-10.26 – Audit Response U21870-SA-CE-224

12 • S-10.27 – Audit Response U21870-SA-CE-225

13 • S-10.28 – Audit Response U21870-SA-CE-226

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

15 A. Yes.

16 Q. Please provide a summary of your testimony.

17 A. I am recommending and will be discussing adjustments for the following projects:

18 Customer Self-Service Mobile Application, Low Moderate Income Customer

19 Support Enhancements, Web Chat AI, Web Dashboard Redesign, and Web

20 Rebate for Personalization projects, all of which are part of the larger Product

21 Family Enhancements – Customer – Capital project from Company Exhibit A-20

22 (SHB-5) and the Low Moderate Income Customer Support Enhancement project

23 from Company Exhibit A-12 (JRB-1), Schedule B-5.3.

DIRECT TESTIMONY OF BRITTNEY KLOCKE**CASE NUMBER U-21870****PART II**

1 Q. What are Staff's recommendations regarding the Customer Self-Service Mobile
2 Application (Mobile App or App)?

3 A. Staff is recommending disallowance of the requested costs within the Product
4 Family Enhancements – Customer – Capital project from Company Exhibit A-20
5 (SHB-5), lines 14, 112, 193 and 269 for the Mobile Application. This represents
6 a decrease of \$1,056,334 in historical capital costs for the year ended 12/31/2024
7 and \$1,305,671 in capital costs for the year ending 12/31/2025. (Staff Exhibit S-
8 10.2.)

9 Q. Why is Staff recommending a full disallowance of costs associated with the
10 Mobile App?

11 A. Staff's position regarding the Mobile App has remained consistent in every case it
12 has been presented in, starting with Case Nos. U-20697, U-20963, U-21224, U-
13 21389, electric cases, and Case Nos. U-21148, U-21308, U-21490 and U-21806,
14 gas cases. In each of those cases, Staff's position is that the Mobile App
15 represents a functionality that is duplicative of the Company's website, and is thus
16 unnecessary.¹ At over \$10 million, this very expensive project should not have its
17 costs passed on to ratepayers.² The Mobile App itself offers functionality that is
18 redundant to that offered by the Company's website and the Company has never
19 proven customers' need or interest in it.

20 Q. Can you please articulate in additional detail why Staff finds the need for the
21 Mobile App – and thus any enhancements to it – has not been proven?

¹ See U-21490 Company exhibit A-20 (SHB-5), line 22.

² *Id.*

DIRECT TESTIMONY OF BRITTNEY KLOCKE**CASE NUMBER U-21870****PART II**

1 A. Yes. The Company also states that the App “does not include the entirety of the
2 website’s information” and Staff questions why this technology is something
3 ratepayers should have to fund since it is redundant to that of the website and
4 offers even less information.³ Everything customers can do with the Mobile App
5 they can also do on the website, whether using a desktop computer or mobile
6 device. The overall usage of the App still trails behind the website with over 1
7 million Business Partner (BP) numbers logging into the website and 356,553 BPs
8 via the App in 2024. (Staff Exhibit S-10.8.) When asked to describe what
9 constitutes a “session” of customer usage of the App, the Company revealed that a
10 user merely accessing the App and then ending their interaction with either a
11 period of inactivity or user sign-out is how the Company tracks the customers’
12 usage of the App. (Staff Exhibit S-10.9.) Unlike the website, the Mobile App is
13 not a necessity and Staff does not find further recovery in this investment to be
14 prudent.

15 Another ongoing issue with the Mobile App is the Company being unable to show
16 strong customer desire for such an app. The Company stated that in 2021, prior to
17 the launch of the App, just 169 customers noted that an App was a platform they
18 were requesting. (Staff Exhibit S-10.10.) This is a shockingly low amount for a
19 Company with a total customer base of 6.8 million customers.⁴ Further, though it
20 was noted that over 1 million customers have downloaded the App, downloading

³ See U-21490, Mclean 2 TR 798.

⁴ See Consumers Energy About Us webpage, available online at <https://www.consumersenergy.com/about-us/who-we-are/corporate-overview>, accessed 9/15/2025.

DIRECT TESTIMONY OF BRITTNEY KLOCKE**CASE NUMBER U-21870****PART II**

1 it does not equal usage. (Staff Exhibit S-10.1.) In fact, just 28% of the
2 Company's digital traffic is from the App. (*Id.*)
3 In the Commission Order for Case No. U-20697 part of the rationale behind the
4 Commission's decision to disallow the requested costs for the App were because
5 it was anticipated that just 30% of the Company's customers would use it.⁵ Now
6 after several years of availability, the App's usage has plateaued at under 30%.
7 That reason alone demonstrates that the App has not proved its usefulness and
8 further cost recovery for it should be denied. For all these reasons, the costs from
9 the Product Family Enhancements – Customer – Capital project for the Mobile
10 Application in the amount of \$1,056,334 in historical capital costs for the year
11 ended 12/31/2024 and \$1,305,671 in capital costs for the year ending 12/31/2025
12 should be disallowed. (Staff Exhibit S-10.2.)

13 Q. What are Staff's recommendations regarding the Low Moderate Income (LMI)
14 Customer Support Enhancements project?

15 A. Staff recommends full disallowance of the requested costs for the LMI Customer
16 Support Enhancement, which represents \$1.87 million in capital expenditures for
17 the test year ending 4/30/2027, which corresponds with Company Exhibit A-12
18 (JRB-1), Sch B-5.3. There is an additional \$525,246 in capital expenditures for
19 the bridge year period ending 12/31/2025 that fall under the Product Family
20 Enhancements – Customer – Capital project and Company Exhibit A-20 (SHB-5).
21 (Staff Exhibit S-10.2.)

⁵ See U-20697 Order, pages 130 & 132.

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1 Q. Why is Staff recommending disallowance of the requested costs for the LMI
2 Customer Support Enhancement?

3 A. According to the Company, the LMI Customer Support Enhancement is designed
4 to support LMI customers in “reducing their utility bill by driving greater
5 awareness and enrollment into eligible programs and services” in the hopes that
6 this will allow customers to alleviate their energy burden, reduce the risk of
7 service disconnections due to unpaid bills, and ultimately improve household
8 stability.⁶ Per the Company, currently only 1 in 6 LMI customers engage in
9 assistance programs and the LMI project aims to increase that engagement to 1 in
10 3 LMI customers.⁷ (Staff Exhibit S-10.19.)
11 Staff has attempted to ascertain exactly what the LMI Customer Support
12 Enhancement will do or will offer customers and still does not have a clear
13 answer. Despite many audit responses from the Company that laid out the project
14 parameters to demonstrate how this project will function, the tangible results
15 remained unclear to Staff. I will begin by discussing the four core functions of
16 the LMI project and provide Staff’s concerns on them.

17 Q. Please discuss the first core function of the LMI project.

18 A. The first core function of the LMI project is Simplified Enrollment. This function
19 will consist of the following: streamlining the “user flow to allow customers to
20 find and enroll in relevant programs,” “creating a centralized platform where
21 customers can view all available assistance programs in one place,” providing

⁶ Prefiled direct testimony of Company witness Jessica R. Byrom, p. 25.

⁷ *Id.* at p. 26.

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1 “clear, step-by-step guidance throughout the enrollment process to minimize
2 confusion and errors,” and ensuring the enrollment process is mobile-friendly.
3 (Staff Exhibits S-10.20 & 10.26.) This function is projected to cost \$600,000.
4 (Staff Exhibit S-10.22.) No new programs will be created under this function;
5 rather, it will simply be made more clear where customers can *find* these
6 programs and enroll in them. It is unclear to Staff why so much money is needed
7 for this function that amounts to directing customers where to enroll in programs.

8 Q. Please discuss the second core function of the LMI project.

9 A. The second core function of the LMI project is Proactive Communications and
10 Program Awareness. This function is described as building “the capability to
11 proactively identify and reach out to customers who are showing early signs of
12 crisis. This involves using data analytics to detect customers at risk and initiating
13 contact to educate them about available assistance options.” (Staff Exhibit S-
14 10.20.) It will also direct customers to the “streamlined, digital flow” and
15 “implement education initiatives to increase awareness about assistance programs
16 and how to access them. This will involve targeted communication campaigns
17 and partnerships with community organizations.” (Staff Exhibit S-10.20.)
18 Customers will be offered personalized communication options, allowing them to
19 choose their preferred method of contact. (Staff Exhibit S-10.20.) This function
20 is projected to cost \$370,000. (Staff Exhibit S-10.22.) However, Staff struggles
21 to understand why so much money is needed to make customers aware of
22 program options that are already present on the Company’s website and other

DIRECT TESTIMONY OF BRITTNEY KLOCKE
CASE NUMBER U-21870
PART II

1 means such as mailings.⁸ Customers may also already choose or update their
2 contact method through the website.

3 The Company plans to allocate \$120,000 of the \$370,000 to targeted outreach
4 campaigns, specifically tracking at-risk customers. (Staff Exhibits S-10.20 and S-
5 10.22.) Staff's issue with this is that the Company has not demonstrated the
6 ability to reach all customers who could potentially be in crisis. The LMI
7 project will target low-income customers who are considered to be "in crisis and
8 facing immediate challenges in paying their energy bills", as well as moderate-
9 income customers who are considered "one crisis away from financial hardship.
10 (Staff Exhibit S-10.28.) Staff is not convinced that the Company's definition of
11 customers in crisis adequately captures all those customers who *could* end up in
12 crisis and believes all customers, not just those identified by the Company as low-
13 to-moderate income, should have access to all the information the LMI project
14 provides. (*Id.*) In Staff's opinion, the best avenue to disseminate this information
15 is via the Company's existing website or mailings, which can reach all customers,
16 including ones the Company may not know are on the cusp of needing these
17 services.

18 Q. Please discuss the third core function of the LMI project.

19 A. The third core function of the LMI project is New and Improved LMI Offerings.
20 This is described as integrating "existing offerings such as payment plans, EWR,
21 demand response, and renewable energy programs. This integration will provide

⁸ See Consumers Energy Company Compare Programs webpage, available online at <https://www.consumersenergy.com/residential/savings-and-clean-energy/save-money-and-energy/compare-programs>, accessed September 16, 2025.

DIRECT TESTIMONY OF BRITTNEY KLOCKE**CASE NUMBER U-21870****PART II**

1 customers with a comprehensive support system, ensuring they can easily identify
2 and access the best options to reduce their energy burden without having to search
3 extensively.” (Staff Exhibit S-10.20.) This function will also redesign programs
4 to better serve LMI customers, “making them more accessible and user-friendly.”
5 (Staff Exhibit S-10.20.) This function is projected to cost \$700,000. (Staff
6 Exhibit S-10.22.) This facet of the of the LMI project is very costly and Staff is
7 unclear as to why a new program such as this one would is projected to need such
8 expensive improvements already. It is also unclear what the new offerings funded
9 by this function would be. Additionally, “ongoing maintenance” will be required,
10 along with anticipated annual updates. (Staff Exhibit S-10.25.) It is therefore
11 likely that more costs for improvements to the LMI project, in addition to the
12 \$700,000 being requested here, can and very will be requested in the future and
13 those costs remain unknown at this time. (*Id.*)

14 Q. Please discuss the fourth core function of the LMI project.

15 A. This fourth core function is Continuous Improvement and Feedback, which is
16 described as the Company collecting feedback from customers and stakeholders
17 to “continuously improve the user flow and outreach strategies,” as well as using
18 customer feedback to “identify and address any barriers to program participation”
19 and implementing a “feedback loop that allows customers to easily share their
20 experiences and suggestions for improvement.” (Staff Exhibit S-10.20.) This
21 function is projected to cost \$200,000 and will also establish performance and
22 feedback metrics. (Staff Exhibit S-10.22.) Nowhere has the Company
23 demonstrated why this function will cost so much; seemingly, this function will

DIRECT TESTIMONY OF BRITTNEY KLOCKE
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PART II

1 just be dedicated to collect data from the Company's customers who interact with
2 the LMI tool.

3 Q. Please discuss other reasons Staff recommends a disallowance for the LMI
4 Customer Support Enhancement project.

5 A. When asked how the Company foresees the LMI project as a long-term solution
6 for customers either in crisis or on the verge of crisis, the Company stated the
7 following: "[b]y streamlining the process of finding and enrolling in assistance
8 programs, the LMI Customer Support Enhancement project will significantly
9 enhance the overall customer experience, providing a robust and sustainable
10 support system for those in need." (Staff Exhibit S-10.27.) This response does
11 not answer the question asked regarding a long-term solution for LMI customers
12 and nowhere in this response did the Company acknowledge that this information
13 is already available to its customers and this project will simply be a new way to
14 disseminate that information. Indeed, on the Company's website there is already
15 a link to Payment Plans and Assistance areas.⁹ The LMI project will not change
16 or enhance the current website options and Staff sees no reason to support the
17 funding of this \$2 million project when the information this project would provide
18 should already be available on the Company's website.

19 Additionally, the number of customers the Company surveyed
20 regarding the LMI project is very low: the Company conducted 6 "usability tests"
21 with 104 participants; just 54% (56) of those participants were Michigan

⁹ 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 September 16, 2025.

DIRECT TESTIMONY OF BRITTNEY KLOCKE**CASE NUMBER U-21870****PART II**

1 residents. (Staff Exhibit S-10.24.) A “Self-Identification Validation” survey was
2 conducted among 1,967 of the Company’s customers, and 60 LMI customers
3 were surveyed regarding the account dashboard redesign. (*Id.*) Just 13 LMI
4 participants – who were not even the Company’s own customers – conducted a
5 diary study to generate broad LMI insights. (*Id.*) For a company with literally
6 millions of customers, the effort and amount of customers surveyed for this
7 expensive project is extremely low.

8 Finally, the Company claims that the LMI Customer Support project
9 “aligns with the priorities of the MPSC’s Energy Affordability and Accessibility
10 Collaborative (EAAC) and Low-Income Energy Policy Board” which emphasizes
11 the importance of streamlining energy assistance and program enrollment
12 processes. (Staff Exhibit S-10.21.) Staff does appreciate the Company’s
13 commitment to fulfilling the priorities of the EAAC and the Low-Income Energy
14 Policy Board but remains unconvinced that the LMI project is the correct way to
15 fulfill those priorities. The information that this project proposes to distribute to
16 customers already exists on the Company’s website. Staff does not understand
17 how a project projected to cost *at least* \$2 million has such vague benefits as
18 making interactions “more accessible, supportive, and efficient” for LMI
19 customers. (Staff Exhibit S-10.20.) For all these reasons, Staff recommends full
20 disallowance of the LMI Customer Support Enhancement project.

21 Q. Is there anything else regarding the proposed disallowance for the LMI Customer
22 Support Enhancement project you would like to address?

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1 A. Yes. Regarding my recommendation for the above adjustment of \$1.87 million in
2 capital expenditures for the test year ending 4/30/2027, which corresponds with
3 Company Exhibit A-12 (JRB-1), Sch B-5.3, it should be noted that my analysis
4 concluded after Staff's revenue deficiency was finalized. Thus, the impacts of
5 this adjustment are not reflected in the testimony and exhibits of other Staff
6 witnesses or in the Staff's revenue deficiency supported by Staff witness
7 Nichols. However, all impacts of this adjustment will be included in Staff's Brief.

8 Q. What are Staff's recommendations regarding the Web Chat Artificial Intelligence
9 (AI) project?

10 A. Staff is recommending disallowance of the requested costs within the Product
11 Family Enhancements – Customer – Capital project from Company Exhibit A-20
12 (SHB-5), lines 14, 112, 193 and 269 for the Web Chat AI project, representing
13 \$157,574 in capital expenditures for the partial bridge year ending 4/30/2026 and
14 \$315,148 in capital and \$19,896 in O&M for the partial test year ending
15 12/31/2026. (Staff Exhibits S-10.2, line 22 & S-10.15.)

16 Q. Why is Staff recommending disallowance of the requested costs for the Web Chat
17 AI project?

18 A. Staff believes the Web Chat AI project offers technology that is redundant and not
19 worth the cost as it brings little value to customers. As described by the Company
20 in an audit response, the Web Chat AI “will utilize an automated Artificial
21 Intelligence (AI)-powered chat dialog that would provide instant, 24/7 customer
22 support, offering quick responses to common queries.” (Staff Exhibit S-10.12.)
23 In addition, it was stated that the Company primarily plans to have the Web Chat

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1 AI tool use information from the Company's existing website and data as its
2 primary source of information. (Staff Exhibit S-10.13.) In essence, the Web Chat
3 will simply be aggregating information that is already available to customers on
4 the Company's website. As stated by the Company, there is already a Frequently
5 Asked Questions page for specific programs and topic areas on the Company's
6 website. (Staff Exhibit S-10.17.)

7 Q. Please discuss other reasons Staff recommends a disallowance for the Web Chat
8 AI project.

9 A. The Company notes that the Web Chat AI is meant to assist customers "with
10 information about general, most asked questions—similar to an easily searchable
11 comprehensive high-level Frequently Asked Questions." (Staff Exhibit S-10.15.)
12 Customers are already able to search the Company's website directly from its
13 homepage.¹⁰ As the Web Chat AI is meant to contain "high-level, frequently
14 asked questions that resolves customers' general and most sought after inquiries,"
15 it is not clear why any customer could not just search directly from already-
16 existing search bar on the Company's homepage. (Staff Exhibit S-10.13.) Any
17 complex questions with answers that are not available on the website would likely
18 be escalated to a customer service representative, whom are available during
19 regular business hours of Monday-Friday, 7:00am-6:00pm for residential
20 customers and 8:00am-4:30pm for business customers. (Staff Exhibit S-10.14.)
21 If customers are unable to find answers to their queries without help from a

¹⁰ See Consumers Energy Company "Search Consumers Energy" search bar on Company's homepage, available online at <https://www.consumersenergy.com/residential>, accessed September 17, 2025.

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1 customer service agent this would render the 24/7 nature of the Web Chat AI
2 moot.

3 Finally, it is problematic that no reduction in overall costs is
4 anticipated from the Web Chat AI and that the Company's "primary success
5 metric" for it would be an increase in customers' overall experience. (Staff
6 Exhibits S-10.16 & 10.18.) Again, Staff does not see the value of this project
7 when it will cost ratepayers money and merely offer information that is already be
8 on the Company's website. Staff does see value in customers' ability to self-serve
9 using the Company's website but is not persuaded that an AI chatbot is a prudent
10 or useful avenue for this.

11 Q. What are Staff's recommendations regarding the Web Dashboard Redesign
12 project?

13 A. Staff is recommending disallowance of the requested costs within the Product
14 Family Enhancements – Customer – Capital project from Company Exhibit A-20
15 (SHB-5), lines 14, 112, 193 and 269 for the Web Dashboard Redesign project in
16 the amount of \$525,246 in capital costs for the bridge year ending 12/31/2025.
17 (Staff Exhibit S-10.2, line 17.)

18 Q. Why is Staff recommending disallowance of the requested costs for the Web
19 Dashboard Redesign project?

20 A. The Web Dashboard Redesign is proposed in order to "help customers more
21 easily discover programs optimized for them and their situation, as well as gain
22 greater clarity into their energy use and the bill impact resulting from that." (Staff
23 Exhibit S-10.2). According to the Company, customers currently lack visibility

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1 into programs from all aspects and those customers are therefore not engaging in
2 programs that could help manage their bill, especially low-moderate income
3 customers. (*Id.*) The Company states that these customers will be helped by this
4 redesign by more easily being able to discover programs “optimized for them and
5 their situation.” (*Id.*)

6 This project clearly shares overlap with the Simplified Enrollment
7 from the LMI project, as that portion of the project is intended to “develop and
8 implement a streamlined user flow that allows customers to find and enroll in all
9 relevant programs” and is meant for low-moderate income customers, as is the
10 proposed Web Dashboard Redesign. (Staff Exhibits S-10.20 & S-10.2.) This
11 project seems both redundant and unnecessary. Staff was not provided with any
12 further information about this redesign and struggles to understand why more than
13 \$500,000 is needed for it. Further, the Company has not identified how exactly
14 redesigning the dashboard will result in better customer engagement and any such
15 results are speculative at best. Even if the ALJ and Commission decline to
16 disallow the requested expenditures for the LMI project, they should disallow the
17 requested expenditures for the Web Dashboard Redesign project due to the
18 overlap between the two projects.

19 Q. What are Staff’s recommendations regarding the Web Rebate for Personalization
20 project?

21 A. Staff is recommending disallowance of the requested costs within the Product
22 Family Enhancements – Customer – Capital project from Company Exhibit A-20
23 (SHB-5), lines 14, 112, 193 and 269 for the Web Rebate for Personalization

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1 project in the amount of \$87,541 for the partial bridge year ending 4/30/2026 and
2 \$175,082 in capital and \$16,580 in O&M for the partial test year ending
3 12/31/2026. (Staff Exhibit S-10.2, line 21.)

4 Q. Why is Staff recommending full disallowance of the requested costs for the Web
5 Rebate for Personalization project?

6 A. The Company stated that currently, customers do not see rebates that are
7 customized or relevant to their individual situation. (Staff Exhibit S-10.2.) The
8 Company intends for the Web Rebate for Personalization project to ensure that
9 customers only see rebates they are likely to use. (*Id.*) When asked to provide
10 more information regarding this project and its costs, Staff was informed that the
11 small blurb provided in Company audit response U21870-SA-CE-
12 051_Baker_ATT_1 regarding the project is the only information and cost
13 breakdown they can provide. (Staff Exhibit S-10.3.) There has been very little
14 provided by the Company regarding this project and it remains unclear to Staff
15 why and how this money is needed for this project.

16 In addition, the Company states that this project is necessary at this
17 time to help with affordability by informing customers of rebates. (Staff Exhibit
18 S-10.5.) However, the Company also states that the website already offers a
19 search option for rebates, albeit a general one, as well as direct marketing to
20 customers to inform them of rebates that may be good fit for them. (*Id.*) Indeed,

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1 there is an entire webpage on the Company's website dedicated to rebates and
2 discounts and that should suffice to inform customers of applicable rebates.¹¹

3 Finally, the costs for this project were determined by projecting a
4 "high-level work effort of 2,500 hours based on the description of capabilities," so
5 those costs are not necessarily accurate as they are based on conjecture. (Staff
6 Exhibit S-10.6.) Staff questions the reasonableness of a project's cost projection
7 whose costs are so unknown. In addition, the project is not expected to reduce
8 costs from any area in the Company. (*Id.*) Given all this, Staff cannot support
9 this project and recommends full disallowance of the requested costs.

10 Q. Please provide a summary of your testimony.

11 A. My testimony provided reasoning for Staff's recommended disallowances for
12 capital and O&M expenses for the Product Family Enhancements – Customer –
13 Capital project from Company Exhibit A-20 (SHB-5) and the Low Moderate
14 Income Customer Support Enhancement project from Company Exhibit A-12
15 (JRB-1), Schedule B-5.3. (Staff Exhibit S-14.0.)

16 Q. Does this conclude your testimony?

17 A. Yes.

¹¹ See Consumers Energy Company Rebates & Discounts webpage, available online at <https://www.consumersenergy.com/residential/savings-and-clean-energy/rebates>, accessed September 17, 2025.

1 MR. SONNEVELDT: Next, Your Honor, Staff moves
2 to bind in the direct testimony of Emma Zichi. Her direct
3 testimony consists of a cover sheet and 15 pages of
4 questions and answers. She also sponsors Exhibits S-14.0
5 and S-14.1.

6 JUDGE THOITS: Are there any objections to the
7 admission of this testimony of these exhibits?

8 Hearing none. The direct testimony of Emma
9 Zichi is bound under the record, and Exhibits S-14.0 and
10 S-14.1 are admitted.

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STATE OF MICHIGAN
BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

Case No. U-21870

In the matter of the application of
CONSUMERS ENERGY COMPANY
for authority to increase its rates for
the generation and distribution of
electricity and for other relief.

QUALIFICATIONS AND DIRECT TESTIMONY OF

EMMA ZICHI

MICHIGAN PUBLIC SERVICE COMMISSION

September 30, 2025

**QUALIFICATIONS AND DIRECT TESTIMONY OF
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1 Q. Please state your full name and business address for the record.

2 A. My name is Emma Zichi, and my business address is 7109 W. Saginaw Hwy., Lansing,
3 MI 48917.

4 Q. By whom are you employed and in what capacity?

5 A. I am employed by the Michigan Public Service Commission (MPSC or Commission) as
6 an Analyst in the Data Access, Privacy and IT (DAPIT) Section of the Customer
7 Assistance Division (CAD).

8 Q. Please describe your educational background.

9 A. I earned a Bachelor of Science in Psychology from Michigan State University in 2021
10 and a Master of Social Work degree from the University of Michigan in 2022.

11 Q. What is your professional experience?

12 A. I began working at the MPSC as an Analyst within the DAPIT section in 2024. My
13 responsibilities include analyzing utilities' rate case cost recovery requests related to
14 Information Technology (IT) as well as Physical and Cyber Security. Prior to working at
15 the MPSC I worked as an Outpatient Therapist and at Auto-Owners Insurance as an
16 Associate Quality Analyst where I tested company software systems to ensure quality and
17 accuracy of system changes.

18 Q. Have you received any work-related training since your employment with the MPSC?

19 A. Yes. I have completed the Annual Regulatory Studies Program (CAMP): The
20 Fundamentals course, hosted by the Institute of Public Utilities (IPU) at Michigan State
21 University. I have also completed the NARUC RTI Rate Case Basics – How to Read and
22 Analyze a Rate Case training.

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1 Q. Have you previously filed testimony before the Commission?

2 A. Yes. I have filed testimony in the following cases:

3 • U-21806 Consumers Energy Gas Rate Case

4 • U-21860 DTE Electric Rate Case

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

6 A. The purpose of my testimony is to present the Michigan Public Service Commission
7 Staff's (Staff) recommendations regarding Consumers Energy Company's (Consumers or
8 the Company) request for recovery of proposed Information Technology (IT) capital
9 expenditures for the bridge period and projected test year, and IT investment O&M
10 expenditures for the test year in this case. Additionally, I will present Staff's position
11 regarding the Company's requests for the SAP S/4 HANA upgrade project.

12 Q. Are you sponsoring any exhibits in this proceeding?

13 A. Yes. I am sponsoring the following exhibits:

14 Exhibits:

15 S-14.0: Staff's Adjustments to IT Capital and Investment O&M by Project

16 S-14.1: Company Audit Responses

17 Q. Were these exhibits prepared by you or under your direction?

18 A. Yes.

19 Q. What is Consumers Energy Company's total Information Technology expenditures
20 request in this case?

21 A. Consumers is requesting \$44.023 million for the historic year, \$80.310 million in the
22 bridge year (\$52.118 million in 2025 and \$28.191 million for 4 months of 2026), and

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1 \$77.719 million for the 12-month projected test year ending 4/30/2027 in capital
2 expenditures. (Exhibit A-12 (SHB-4), Schedule B-5.1 page 1, line 7.) The Company is
3 also requesting \$26.303 in Investment O&M for the 12-month projected test year ending
4 4/30/2027. (A-19 SHB-3 page 1, line 5.)

5 Q. What adjustments is Staff recommending to Consumers Information Technology
6 expenditures?

7 A. Staff is recommending a total capital disallowance of \$1,056,334 in the historical 12-
8 months ending 12/31/2024, \$2,606,186 in the 12-month bridge period ending 12/31/2025,
9 \$944,130 in the 4-month bridge year period ending 4/30/2026, and \$2,675,579 in the test
10 year ending 4/30/2027. Additionally, Staff is recommending a total investment O&M
11 disallowance \$355,474 in the 12-month projected test year ending 4/30/2027. (Staff
12 Exhibit S-14.0.) These disallowances come from the following Consumers Information
13 Technology programs: Customer, Electric, IT/Digital Foundation, and Security. Staff
14 witness Brittney Klocke will address adjustments in the Customer program and Staff
15 witness Jessica Duell will address an adjustment in the Electric program.

16 Q. What adjustments is Staff recommending to the IT/Digital Foundation program?

17 A. Staff is recommending a disallowance of \$3,046,500 in capital and \$273,946 in
18 investment O&M to the IT/Digital Foundation program. (Staff Exhibit S-14.0.) This
19 recommendation is made up of the following project-level adjustments: ARP –
20 Collaboration, ARP – Field Device Asset Management (FDAM), ARP – Workstation
21 Asset Management (WAM), Digital – Infrastructure Automation, and the ISIS Papyrus. I
22 will address each of these projects below.

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1 Q. What is Staff's recommended adjustment for the ARP – Collaboration project?

2 A. Staff is recommending a partial disallowance of \$250,023 in the 12-month bridge year
3 period ending 12/31/2025, \$46,300 in the 4-month bridge year period ending 4/30/2026,
4 and \$138,902 in the projected test year ending 4/30/2027. (Staff Exhibit S-14.0, line 5.)

5 This adjustment corresponds to the capital expenditures present on Company Exhibit A-
6 20 (SHB-5), pages 18, 27 and 36, lines 143, 217 and 295 and falls within the IT/Digital
7 Foundation program on Exhibit A-12 (SHB-4), Schedule B-5.1, page 1, line 5.

8 Q. Why is Staff recommending this adjustment?

9 A. Staff is recommending this adjustment to correct for an update in the projection that was
10 discovered through audit of the Company's ARP projects. Through audit Staff asked the
11 Company to provide a cost breakdown for all auditorium refreshes included in this
12 project for 2025, 2026 and 2027. In response, the Company stated that the original
13 projection for 2025 was based on costs to replace historical equipment. The Company
14 was able to refresh the historical equipment at a lower cost than what was projected and
15 shared through audit the revised cost estimate for all conference room refreshes taking
16 place in 2025, 2026 and 2027. (Staff Exhibit S-14.1, pages 1-4.) This adjustment is
17 shown on line 5 of Exhibit S-14.0.

18 Q. What is Staff's recommended adjustment for the ARP – Field Device Asset Management
19 (FDAM) project?

20 A. Staff is recommending a full disallowance of all new device purchases for 2026 and 2027
21 included in the ARP-FDAM project, which consists of \$228,567 for the 4-month bridge
22 year period ending 4/30/2026 and \$658,700 for the projected test year ending 4/30/2027.

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1 (Staff Exhibit S-14.0, line 6.) This adjustment corresponds to the capital expenditures
2 presented on Company Exhibit A-22 (SHB-7) page 5, line 3, columns e and f and falls
3 within the IT/Digital Foundation Program on Exhibit A-12 (SHB-4), Schedule B-5.1,
4 page 1, line 5.

5 Q. Why is Staff recommending this adjustment?

6 A. Staff is recommending this adjustment due to a lack of information provided by the
7 Company through audit regarding the methods used to calculate the total projected costs
8 for new purchases in 2026 and 2027. Through audit Staff asked the Company to provide
9 a breakdown of all new device purchases included in Exhibit A-22 (SHB-7) page 5, line
10 3, similar to what is shown for replacements. In the Company's audit response, it shared
11 that the projection for new purchase devices has changed in this case due to the
12 uncertainty of knowing the exact number of new devices needed each year. The Company
13 now reviews actual historical costs over the past four years to ensure its projection is
14 reasonable and prudent. (Staff Exhibit S-14.1, pages 5 and 6.)

15 Q. Why does Staff find this new method for projecting the total cost of new device
16 purchases problematic?

17 A. Staff finds this problematic because the Company did not explicitly state in its audit
18 response that the average of all 4 years of historical data was used to determine the total
19 projected costs of new device purchases. Instead, it stated that the projected costs were
20 validated using historical costs. This response provides uncertainty as to the methods
21 used by the Company to calculate the total projected cost for new device purchases.
22 Additionally, in a follow-up audit question, Staff asked the Company to share the

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1 calculation used that produced the \$1 million in total projected costs for new device
2 purchases. In response to Staff, the Company stated it did not use a calculation to project
3 the cost for new device purchases of \$1 million. Instead, the Company referred Staff to its
4 previous audit response and reiterated that the projected costs were *validated* using actual
5 historical costs. (Staff Exhibit S-14.1, page 15.) The Company failed to provide Staff
6 with a calculation or method used to show how the projected cost of \$1 million was
7 chosen. The Company has failed to provide any support for the projected cost.

8 Q. Does Staff believe the purchase of new devices for the ARP-FDAM project is
9 unnecessary?

10 A. No. Staff understands the importance of new device purchases for this project and does
11 believe the Company will spend money in this area. However, Staff cannot complete a
12 full analysis of these costs if the Company does not share the methods or calculations
13 used to project these costs. The Company failed to provide supporting information
14 showing how the projected costs for new devices purchases of \$1 million were derived.
15 Without a clear explanation for how the Company determined the total projected costs of
16 \$1 million, the costs remain baseless. If the Company has chosen a new way of predicting
17 new device purchases, it should have a method or calculation to support it. Neither
18 Company testimony, supporting exhibits, nor audit responses explained how the \$1
19 million annual spend for new purchase devices was calculated, only how it was
20 *validated*, which is not the same.

21 Q. What is Staff's recommended adjustment for the ARP- Work Station Management

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1 (WAM) project?

2 A. Staff is recommending a full disallowance of all new device purchases for 2026 and 2027
3 included in the ARP-WAM project, which consists of \$228,567 for the 4-month bridge
4 year period ending 4/30/2026 and \$658,700 for the projected test year ending 4/30/2027.
5 (Staff Exhibit S-14.0, line 7.) This adjustment corresponds to the capital expenditures
6 presented on Company Exhibit A-22 (SHB-7) page 15, line 10, columns e and f and falls
7 within the IT/Digital Foundation Program on Exhibit A-12 (SHB-4), Schedule B-5.1,
8 page 1, line 5.

9 Q. Why is Staff recommending this adjustment?

10 A. Staff is recommending this adjustment due to a lack of information provided by the
11 Company in its application and through audit regarding the methods used to calculate the
12 total projected costs for new purchases in 2026 and 2027. Staff's adjustment for the ARP-
13 WAM project is consistent with the ARP-FDAM project. Through audit Staff asked the
14 Company to provide a breakdown of all new device purchases included in Exhibit A-22
15 (SHB-7) page 5, line 3, similar to what is shown for replacements. In the Company's
16 audit response, it stated that the projection for new purchase devices has changed in this
17 case due to the uncertainty of knowing the exact number of new devices needed each
18 year. The Company now reviews actual historical costs over the past four years to ensure
19 its projection is reasonable and prudent. (Staff Exhibit S-14.1, pages 7 and 8.)

20 Q. Why does Staff find this new method for projecting the total cost of new device
21 purchases problematic?

22 A. As stated above regarding the ARP-FDAM project, the Company does not specify that

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1 the projection is based on historic actuals, just that it is validated by it. Additionally, the
2 Company confirmed that it did not use a calculation to project the cost of \$1 million,
3 leaving Staff to question how it arrived at its projection.

4 Q. Does Staff believe the purchase of new devices for the ARP-WAM project is
5 unnecessary?

6 A. No. Staff understands the importance of new device purchases for this project and does
7 believe the Company will spend money in this area. However, the prudence of this
8 projection cannot be analyzed if the Company does not share the methods or calculations
9 used to project these costs. The Company failed to provide supporting information
10 showing how the projected costs for new devices purchases of \$1 million were derived.
11 Without a clear explanation for how the Company determined the total projected costs of
12 \$1 million, the costs remain baseless and unsupported. If the Company has chosen a new
13 way of predicting new device purchases, it should have a method or calculation to
14 support it. Neither Company testimony, supporting exhibits, nor audit responses explain
15 how the \$1 million annual spend for new purchase devices was calculated, only how it
16 was *validated*.

17 Q. What is Staff's recommended adjustment for the Digital-Infrastructure Automation
18 project?

19 A. Staff is recommending a full disallowance of the Digital-Infrastructure Automation
20 project, which consists of \$382,043 for the 12-month test year ending 4/30/2027. (Staff
21 Exhibit S-14.0, line 8.) This adjustment corresponds to the capital expenditures presented
22 on Company Exhibit A-20 (SHB-5), page 37, line 307, and falls within the IT/Digital

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1 Foundation program on Exhibit A-12 (SHB-4), Schedule B-5.1, page 1, line 5. Staff is
2 also recommending a partial disallowance of \$159,902 in investment O&M, which falls
3 within the Information Technology Investment O&M program on Exhibit A-19 (SHB-3),
4 page 1, line 3 and corresponds to the O&M expenses shown on Exhibit A-20 (SHB-5),
5 page 37, line 307.

6 Q. Why is Staff recommending these adjustments?

7 A. Staff is recommending these adjustments due to a lack of information from the Company
8 supporting the prudence of this project. The Company stated in testimony that the efforts
9 completed through this project would lead to a reduction in operational costs¹. However,
10 through audit the Company failed to quantify this reduction.

11 Q. What information did Staff learn through audit about the project's expected reduction in
12 costs?

13 A. Through audit Staff asked the Company to provide the reduction to operational costs it
14 expected to gain from the project. In response, the Company stated that there will not be a
15 reduction in operational costs as a result of this project. It further shared that the project
16 would instead provide efficiency and avoid costs. (Staff Exhibit S.14.1, pages 10-12.) In
17 the Company's testimony it states in the project's "Alternatives" section that sticking with
18 the current, manual, system is costly among other things, and this is why the Company
19 did not choose this option². The Company asserts the need for this project due to
20 expected cost reductions but cannot support this when asked by Staff through audit. In a

¹ Prefiled direct testimony of Company witness Stacy H. Baker, page 98.

² *Id* at page 99.

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1 follow-up audit request, Staff asked the Company to explain why there are no cost
2 savings as a result of this project, considering the current solution is costly. Similarly, the
3 Company shared that the project will not result in hard cost savings but will result in
4 operational efficiencies and reduce the current manual process by 80%. (Staff Exhibit S-
5 14.1, page 18.) Again, the Company failed to provide information supporting the
6 expected cost savings, as stated two times in testimony. Furthermore, Staff cannot
7 understand why there would not be a reduction in costs if the project will reduce manual
8 efforts by 80%. The Company has not proven the prudence of this project, considering it
9 states the project will reduce operational costs and was unable to confirm or quantify
10 these cost reductions.

11 Q. What is Staff's recommended adjustment for the ISIS Papyrus project?

12 A. Staff is recommending a full disallowance of the ISIS Papyrus project, which consists of
13 \$164,499 in the projected 4-month bridge year period ending 4/30/2026, and \$263,199
14 for the 12-month test year ending 4/30/2027. (Staff Exhibit S-14.0, line 9.) This
15 adjustment corresponds to the capital expenditures presented on Company Exhibit A-20
16 (SHB-5), page 28, line 228 and falls within the IT/Digital Foundation program on Exhibit
17 A-12 (SHB-4), Schedule B-5.1, page 1, line 5. Staff is also recommending a partial
18 disallowance of \$144,044 in O&M for the 12-month test year ending 4/30/2027, and falls
19 under the Information Technology Investment O&M program on Exhibit A-19 (SHB-3),
20 page 1, line 3, and corresponds to the O&M expenses shown on Exhibit A-20 (SHB-5),
21 page 28, line 228.

22 Q. Why is Staff recommending this adjustment?

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1 A. Staff is recommending this adjustment due to a lack of information from the Company
2 supporting the prudence of this project at this time. Through audit Staff asked the
3 Company what would happen with vendor support and cyber security patches if the
4 upgrade was not completed at this time. In response the Company shared that the vendor
5 would continue to provide support even if the upgrade is not completed now. It also
6 shared some concerns with delaying the upgrade. Additionally, the Company confirmed
7 that the vendor would still provide cybersecurity patches, but that they may only apply to
8 future releases. (Staff Exhibit S-14.1, page 9.) Staff asked the Company when the vendor
9 will stop providing support and to clarify whether cybersecurity patches will continue to
10 be available if the system is not upgraded. The Company shared that the vendor has not
11 established a definitive end date for support of the current version and that historically,
12 support has been provided contingent upon the Company maintaining its annual
13 maintenance agreement. Additionally, the Company confirmed that similarly, the
14 cybersecurity patches will continue to be provided and that the vendor has not identified a
15 specific end date for these patches to users who have not upgraded. (Staff Exhibit S-14.1,
16 page 16.) The Company provided reasoning in testimony and audit for why this project
17 could be necessary but failed to provide definitive information as to why completing this
18 upgrade was necessary now.

19 Q. Has this cost previously been recommended for disallowance?

20 A. No, however, Staff has discovered new information through audit that supports a change
21 in Staff's position. The Company shared in audit that the vendor will continue to provide
22 support and cybersecurity patches to the current version. The Company shared possible

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1 concerns about not completing at this time but did not provide any concrete information
2 to support the need to complete the upgrade now.

3 Q. What adjustments is Staff recommending to the Security program?

4 A. Staff is recommending a disallowance of \$50,579 in O&M to the Security program. This
5 recommendation is made up of the following project-level adjustments: Business
6 Continuity – Program Management Tool. I will address this project below.

7 Q. What is Staff's recommended adjustment for the Business Continuity – Program
8 Management Tool project?

9 A. Staff is recommending a full disallowance of the Business Continuity – Program
10 Management Tool project, which consists of \$50,579 in O&M expenses for the 12-month
11 test year ending 4/30/2027. (Staff Exhibit S-14.0, line 11.) This adjustment corresponds
12 to the investment O&M expenditures presented on Company Exhibit A-20 (SHB-5), page
13 39, line 325, and falls within Security Investment program on Exhibit A-19 (SHB-3),
14 page 1, line 4.

15 Q. Why is Staff recommending this adjustment?

16 A. Staff is recommending this adjustment due to new information learned through audit
17 regarding past decisions made by the Company for this project. Through audit, Staff
18 learned that the Company has been using the current system, Riskconnect, since 2023. The
19 Company shared that the current system does not meet Federal Emergency Management
20 Administrative (FEMA) and Incident Command System (ICS) standards adopted by the
21 Company, and thus it's looking to implement a new system. (Staff Exhibit S-14.1, pages
22 13-14.) Through a second round of audit, Staff discovered that the Company adopted

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1 these standards in 2013. The Company also shared that implementing a new system is not
2 the only way to meet these standards adopted by the Company, but the current system
3 does not have the capabilities to support the requirements. (Staff Exhibit S-14.1, page
4 17.)

5
6 Staff believes that this new information learned through audit does not support the
7 Company's reasoning for implementing this project. Logically, if the standard were
8 adopted in 2013, the current system put in place in 2023 would have adhered to these
9 standards, were it deemed prudent by the Company. The Company failed to address this
10 inconsistency and provide supporting information as to the prudence of adopting these
11 standards now.

12 Q. Has this cost previously been recommended for disallowance?

13 A. No, however the shifting in costs and new information Staff discovered through audit
14 supports a change in Staff's position.

15 Q. How has this project changed from the Company's most recent gas case, Case no.
16 U-21806?

17 A. Yes. Projected costs were included for this project in the previous electric case, U-21585,
18 for 2025 and 2026. (Exhibit A-88 (SK-6), lines 205 and 272.) In the current gas case, U-
19 21806, this project has projected costs included for only 2026. (Exhibit A-20 (SHB-5)
20 page 27, line 381.) In this case the Company included projected costs for 2026 and 2027.
21 (Exhibit A-20 (SHB-5) page 30, line 249 and page 39, line 325.) The Company has
22 shifted this project from 2025 and 2026 to 2026 and 2027 across cases. Additionally,

**QUALIFICATIONS AND DIRECT TESTIMONY OF
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1 through audit Staff learned that the Company has not selected a vendor or new software
2 yet. (Staff Exhibit S-14.1 page, 13 and 14.) This project has been shifted to different
3 years across cases and the total company expected project O&M cost has continuously
4 decreased across cases starting in U-21490 through this cases, with a total decrease of
5 \$431,460. Due to this constant decrease in projected costs, change in implementation
6 dates, requiring recovery for the project without having selected a vendor or new solution,
7 and the past decisions that contradict the current need for this project, Staff believes this
8 project has not been supported by the Company or proven to be prudent at this time.

9 Q. What special rate-making requests did the Company include in this case for the SAP
10 S/4HANA Implementation project?

11 A. The Company is requesting to amortize the cloud implementation costs for the SaaS
12 (software as a service) solution over a 15-year asset life. This will be addressed by Staff
13 witness McMillan-Sepkoski. Additionally, the Company is requesting to defer the
14 Investment O&M expenses and recover these costs over the life of the asset. This will be
15 addressed by Staff witness Nichols.

16 Q. Does Staff have other recommendations regarding the SAP S/4HANA upgrade?

17 A. Yes. Staff is recommending the Commission direct the Company to meet with Staff
18 quarterly to inform them on progress of the SAP S/4HANA implementation project. Staff
19 would like these updates to include any advancements and/or setbacks in project
20 implementation, budget adherence, changes to the project scope, timeline, expenses, and
21 any problems the Company has experienced or anticipates experiencing with any
22 operations or customer interactions.

**QUALIFICATIONS AND DIRECT TESTIMONY OF
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1 Q. Does Staff have any additional recommendations regarding the SAP S/4HANA upgrade?

2 A. Yes. Additionally, Staff recommends the Company record any over and under recovery of
3 each projected expense in the SAP S/4HANA implementation, compared to the 80% base
4 (ROM projected investment), to be included in the Company's future rate cases until
5 implementation is complete. This will allow Staff to see how the allocated funds relate to
6 the costs spent on each planned objective.

7 Q. Please summarize your recommendations.

8 A. Staff is recommending a full disallowance of both capital and O&M expenditures for
9 multiple IT projects, and one Security project. One project disallowance is to correct an
10 updated projection identified by the Company through audit. Two projects have
11 recommendations based on unsupported costs, where the Company failed to provide
12 supporting information, through audit, as to the methods used to determine these costs.
13 All other disallowances are based on a lack of information provided by the Company,
14 through audit, to support the immediate prudence of these projects. In total these
15 disallowances account for \$250,023 for the 12-month bridge year ending 12/32/2025,
16 \$667,933 in the 4-month bridge year ending 4/30/2026, and \$2,128,544 in capital and
17 \$324,525 in O&M for the 12-month projected test year ending 4/30/2027. Staff also
18 presents recommendations for the SAP S/4 HANA project, including meeting with Staff
19 to provide updates and tracking expenditures.

20 Q. Does this conclude your testimony?

21 A. Yes.

1 MR. SONNEVELDT: Next, Your Honor, Staff moves
2 to bind in the direct testimony of Ryan Boutet. His
3 direct testimony consists of a cover sheet and 22 pages of
4 questions and answers. He also sponsors Exhibits S-13.1
5 through S-13.11.

6 JUDGE THOITS: Are there any objections to the
7 admission of this testimony or these exhibits?

8 Hearing none. The direct testimony of Ryan
9 Boutet is bound into the record, and exhibits S-13.1
10 through S-13.11 are admitted.

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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)
generation and distribution of electricity)
and for other relief.)

)

Case No. U-21870

QUALIFICATIONS AND DIRECT TESTIMONY OF
RYAN BOUTET
MICHIGAN PUBLIC SERVICE COMMISSION

September 30, 2025

QUALIFICATIONS OF RYAN BOUTET
CASE NUMBER U-21870
PART I

1 Q. Please state your full name and business address for the record.

2 A. My name is Ryan Boutet (he/him/his), and my business address is 7109 West Saginaw
3 Highway, Lansing, Michigan 48917.

4
5 Q. By whom are you employed and in what capacity?

6 A. I am employed by the Michigan Public Service Commission (MPSC or Commission) as a
7 Public Utilities Engineer in the Electric Operations Section of the Energy Operations
8 Division.

9
10 Q. Please describe your educational background.

11 A. I earned a Bachelor of Science in Mechanical Engineering from Michigan State University
12 in December of 2019, as well as additional minors in Computer Science & Engineering,
13 and German from Michigan State University.

14
15 Q. What is your professional background?

16 A. During my time at Michigan State University I focused my electives on the energy sector
17 and renewable technologies, allowing me to spend a summer abroad on a research program
18 at RWTH Aachen University in Germany in the Summer of 2016, a top technical institute
19 in Europe. There, I conducted comparative research on wind energy conversion rates for
20 various horizontal and vertical-axis turbine configurations, as well as aspects such as
21 economic factors, payback periods, material and construction costs, estimated energy
22 production, and more. Following this, and still during my education at Michigan State
23 University, I took a part-time position with a drone company known as Vision Air Systems,

QUALIFICATIONS OF RYAN BOUTET
CASE NUMBER U-21870
PART I

1 where I worked as a Drone Data Analyst. Vision Air Systems provided drone services
2 primarily focused on visual inspections in construction zones and other hard-to-access
3 industrial areas. My responsibilities included creating and verifying flight paths for drones
4 used in visual inspections, communicating needs between drone operators and clients, and
5 working with drone operators to ensure data and flight paths are properly databased and
6 made available to clients. I remained with Vision Air Systems until late 2018. I joined the
7 MPSC in October of 2023. As a Public Utilities Engineer in the Electric Operations Section
8 of the MPSC, my responsibilities include reviewing electric rate cases, handling customer
9 complaints and safety concerns, and contributing to multiple other efforts to ensure the
10 electrical grid in Michigan stays reliable and safe. Some such examples include projects
11 focused on the needs of critical facilities, projects on defining and supporting grid
12 resilience, and projects focused on performance metrics and incentivized performance for
13 utility companies.

14
15 Q. Have you received any work-related training since starting your employment with the
16 MPSC?

17 A. Yes. The trainings I have completed so far include:

- 18 • OSMOSE: Contact Voltage is Unseen and Unforgiving
- 19 • MPSC Rate Case Training Series
- 20 • Regulatory Training Initiative: Performance Based Ratemaking for Energy Utilities (2023)
- 21 • NARUC/NASEO: Distribution System Planning & Resilience Planning Training
- 22 • Regulatory Assistance Project: Improving Utility Performance Incentives
- 23 • Regulatory Training Initiative: Rate Case Basics (2024)

QUALIFICATIONS OF RYAN BOUTET
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PART I

- Energy Utility Consultants Inc.: Right of Way Management (2024)
- Regulatory Training Initiative: The Basics of Utility Accounting & Ratemaking (2024)
- Michigan State University’s Institute of Public Utilities (MSU IPU): Regulatory Studies Program - Fundamentals Course ‘Camp NARUC’ (2024)
- Regulatory Training Initiative: Utility Credit Ratings 101 (2024)
- Regulatory Training Initiative: Utility Insurance 101 (2024)

Q. Have you previously testified before the Commission?

A. Yes. I have filed testimony in the following cases:

<u>Case No</u>	<u>Company</u>	<u>Type of Case</u>	<u>Subject of Testimony</u>
U-21461	I&M Power	Electric Rate	Storm Expenses & Restoration, Tree Trim
U-21555	UPPCO	Electric Rate	Fleet & Facility Expenses
U-21534	DTE Electric	Electric Rate	Base Capital Programs & Fleet Expense
U-21585	CE Electric	Electric Rate	HVD Capital Program
U-21860	DTE Electric	Electric Rate	Infrastructure Resilience & Hardening Pillar

DIRECT TESTIMONY OF RYAN BOUTET
CASE NUMBER U-21870
PART II

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

2 A. The purpose of my testimony is to provide the Michigan Public Service Commission
 3 Staff's (Staff) insights and recommendations on Consumers Energy Company's (the
 4 Company) proposed investments and programs in its Low Voltage Distribution (LVD)
 5 system, as presented by Company witness Jennifer Partlan.

6
 7 Q. Are you sponsoring any exhibits?

8 A. Yes, I am sponsoring 11 exhibits:

<u>Exhibit No.</u>	<u>Description</u>
10 S-13.1	U-21389 Capital Expenditures Company Exhibit A-122
11 S-13.2	U-21585 Capital Expenditures Company Exhibit A-95
12 S-13.3	CE Discovery Response on CVR benefits
13 S-13.4	CE Discovery Response on 2025 YTD spending
14 S-13.5	CE Discovery Response on Zonal Health Investments
15 S-13.6	CE Discovery Response on Make-Ready Work
16 S-13.7	U-21585 Commission approved Make-Ready Work expenditures
17 S-13.8	U-21585 Make-Ready Work description
18 S-13.9	CE Discovery Response on Right-of-Way projections
19 S-13.10	Staff proposed Inflation Adjustments
20 S-13.11	Summary of Staff LVD Adjustments

21

22

23

DIRECT TESTIMONY OF RYAN BOUTET
CASE NUMBER U-21870
PART II

Low Voltage Distribution Capital Investments

Q. Please provide an overview of the organization of the Company's LVD programs and expenditures included in this instant case.

A. The Company categorizes its capital spending programs by the purpose they serve, such as Reliability programs or Asset Relocation programs. The complete list of programs which include an LVD sub-program is as follows: New Business, Reliability, Capacity, Demand Failures, and Asset Relocations. My analysis will address specific sub-programs and investment categories within the above programs one at a time.

Q. Did the Commission issue any noteworthy disallowances or discussion related to Low Voltage Distribution programs in its March 21, 2025 Order in the Company's previous rate case, MPSC Case No. U-21585?

A. Yes. While the Commission declined to adopt any disallowances to the Company's LVD Lines New Business sub-program, it did ask for an analysis of line installation costs by external contractors versus the Company's workforce in the next electric rate case.¹ Regarding the Company's LVD Lines Reliability sub-program, the Commission adopted a nearly \$200 million disallowance to the test year based on recommendations by the Attorney General (AG). Most of this disallowance, approximately \$178 million, targeted the Zonal Health Improvements investment category, as the Commission agreed that the Company did not provide ample historical cost information or an analysis of the cost effectiveness of these investments to justify a 500% increase in capital spending between

¹ MPSC Case No. U-21585 – Commission Order, March 21, 2025, p. 47.

DIRECT TESTIMONY OF RYAN BOUTET
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PART II

1 the bridge period and test year.² Furthermore on this topic, the Commission shared the
2 ALJ's concern regarding the Company's ability to accomplish its ambitious work plan in
3 zonal health considering the Company's testimony that it does not currently have the
4 workforce to perform on its Reliability Roadmap.³ Also included in the LVD Lines
5 Reliability adjustment was an approximate \$10.2 million disallowance to the Right-of-Way
6 (ROW) investment category that the Commission agreed upon due to a lack of detail
7 regarding the link between projected costs and specific lines to address.⁴ The LVD
8 Repetitive Outages sub-program had disallowances proposed by the AG and supported by
9 the ALJ, however the Commission declined to adopt these disallowances based on the
10 Company's Service Quality Rules (SQR) performance related to customers experiencing 4
11 or more outages a year (CEMI-4), and the impact this program should have on the CEMI-
12 4 metric.⁵ However, the Commission agreed with the ALJ and AG regarding the low
13 spending this sub-program saw in 2023, and resultingly asked Consumers to "...present a
14 robust case in its next electric rate case to demonstrate that these dollars were indeed spent
15 on addressing reliability in LVD repetitive outages."⁶ Lastly, the LVD Lines Capacity sub-
16 program received a disallowance to the Overloaded Equipment investment category based
17 on a lack of support for a nearly seven-fold increase in the anticipated number of projects
18 between the bridge period and test year.⁷

² MPSC Case No. U-21585 – Commission Order, March 21, 2025, p. 63.

³ MPSC Case No. U-21585 – Commission Order, March 21, 2025, p. 63.

⁴ MPSC Case No. U-21585 – Commission Order, March 21, 2025, p. 55.

⁵ MPSC Case No. U-21585 – Commission Order, March 21, 2025, p.73.

⁶ MPSC Case No. U-21585 – Commission Order, March 21, 2025, p.73.

⁷ MPSC Case No. U-21585 – Commission Order, March 21, 2025, p.88.

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PART II

1 Q. Did the Company comply with the Commission request for an analysis of line extension
2 costs between external contractors and internal workforce for the LVD Lines New Business
3 program?

4 A. Yes. Please reference Figure 7 on page 15 of Company witness Partlan's direct testimony.
5

6 Q. Did the Company comply with the Commission request to provide a case that dollars spent
7 in 2023 under the LVD Repetitive Outages program indeed addressed reliability concerns?

8 A. Yes. Company witness Partlan explains on Page 80 of direct testimony that Exhibit A-169
9 (JMP-4) identifies all LVD Repetitive Outages projects that had substantive investment in
10 2023 and/or 2024.
11

12 Q. Please provide an analysis of historical LVD sub-program test year projections in relation
13 to the projected test year amounts in this rate case.

14 A. Please see Table One below for this analysis. The Company has scaled back the large
15 spending increase proposed in its last rate case, MPSC Case No. U-21585. The overall
16 requested LVD sub-program funding in this case is approximately \$207 million higher than
17 that in MPSC Case No. U-21585, whereas the request in MPSC Case No. U-21585 was
18 \$504 million greater than that in MPSC Case No. U-21389. As has been seen across the
19 industry, transformer prices have grown at a rate that greatly outpaces inflation in recent
20 years, and this is reflected in the fact that approximately 64% or \$132 million of the \$207
21 million increase in this case can be attributed solely to transformer purchases. Two other
22 sub-programs see substantial increases in requested funding for this case, the LVD

DIRECT TESTIMONY OF RYAN BOUTET
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Repetitive Outages sub-program and the LVD Lines Relocations sub-program, both of which will be addressed further in my testimony.

Table One: LVD Sub-program Projections by Test Year

<u>LVD Sub-programs</u>	U-21389 Test Year ⁸	U-21585 Test Year ⁹	U-21870 Test Year	Delta (21870-21585)
<u>New Business</u>				
LVD Lines	\$108,674,000	\$128,160,000	\$130,200,000	\$2,040,000.00
Transformers	\$16,796,000	\$75,583,000	\$207,782,000	\$132,199,000.00
<u>Reliability</u>				
LVD Lines	\$41,351,000	\$298,720,000	\$312,886,000	\$14,166,000.00
LVD Substations	\$15,500,000	\$43,725,000	\$42,911,000	-\$814,000.00
LVD Repetitive Outages	\$9,856,000	\$10,141,000	\$30,344,000	\$20,203,000.00
LVD Substations Rehabilitation	\$9,400,000	\$30,667,000	\$31,147,000	\$480,000.00
LVD Lines Rehabilitation	\$32,080,000	\$15,000,000	\$27,135,000	\$12,135,000.00
Resiliency	\$13,103,000	\$22,623,000	\$35,765,000	\$13,142,000.00
<u>Capacity</u>				
LVD Lines	\$14,900,000	\$56,723,000	\$54,911,000	-\$1,812,000.00
LVD Substations	\$13,150,000	\$22,270,000	\$22,251,000	-\$19,000.00
LVD New Business	\$20,511,000	\$20,319,000	\$30,130,000	\$9,811,000.00
CVR	\$3,877,000	\$4,343,000	\$4,070,000	-\$273,000.00
<u>Demand Failures</u>				
LVD Lines Failures	\$84,152,000	\$147,408,000	\$128,350,000	-\$19,058,000.00
LVD Substation Failures	\$7,468,000	\$9,000,000	\$8,961,000	-\$39,000.00
LVD Metering Failures	\$36,216,000	\$45,494,000	\$37,770,000	-\$7,724,000.00
<u>Asset Relocations</u>				
LVD Lines Relocations	\$45,167,000	\$46,309,000	\$79,090,000	\$32,781,000.00
<u>LVD Sub-program Totals</u>	\$472,201,000	\$976,485,000	\$1,183,703,000	\$207,218,000.00

Q. Do you have any recommended disallowances for LVD sub-program capital expenditures in this instant case?

⁸ Data from Staff Exhibit S-13.1

⁹ Data from Staff Exhibit S-13.2

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PART II

1 A. Yes. I have a total of six disallowances to recommend, totaling a bridge period
2 disallowance of approximately \$36.8 million and a test year disallowance of approximately
3 \$51.8 million. I will discuss the following six sub-programs and/or investment categories
4 and their adjustments below: Conservation Voltage Reduction (CVR) sub-program
5 (Capacity Program), LVD Lines Overloaded Equipment investment category (Capacity
6 Program), LVD Lines Zonal Health Improvements investment category (Reliability
7 Program), LVD Repetitive Outages sub-program (Reliability Program), LVD Make-Ready
8 work investment category (Asset Relocations Program), and LVD Right-of-Way
9 investment category (Reliability Program). These adjustments are also summarized in Staff
10 Exhibit S-13.11.

11
12 Q. What is the Company proposing for the CVR sub-program within the Capacity program?

13 A. In the instant case, the Company is proposing a bridge period expenditure of \$5.586
14 million, and a test year expenditure of \$4.070 million, which would allow for CVR to be
15 enabled on 85 circuits in both 2025 and 2026.¹⁰ Figure 58 in Company witness Partlan's
16 testimony also displays that the Company expects to see peak MW reductions of 62 MW
17 in 2025 and 73 MW in 2026, and cumulative MWh reductions of approximately 120,000
18 in 2025 and 144,000 in 2026.

19
20 Q. Does Staff support the Company proposal for the CVR sub-program? If not, explain why.

¹⁰ Direct Testimony of Jennifer Partlan, p. 126.

DIRECT TESTIMONY OF RYAN BOUTET
CASE NUMBER U-21870
PART II

1 A. No, Staff does not support the proposed CVR expenditures. Following a review of the
2 Company's previous two rate cases, there is a clear trend of the Company underspending
3 the allotted funds for the CVR sub-program. For the calendar year 2023, the Company
4 projected spending \$3.093 million on CVR in MPSC Case No. U-21389, shown on line
5 33, column (i) of Staff exhibit S-13.1. However, in MPSC Case No. U-21585 the Company
6 reported 2023 actual expenditures for the CVR program to be \$1.311 million, shown on
7 line 28, column (g) of Staff exhibit S-13.2. Similarly, for the calendar year 2024, the
8 Company projected spending \$3.877 million on the CVR program in MPSC Case No. U-
9 21585, seen on line 28, column (i) of Staff exhibit S-13.2, yet has reported actual historic
10 expenditures in this instant case of \$2.246 million in calendar year 2024 according to line
11 26, column (g) on page 1 of Company exhibit A-113. The Company underspent its 2023
12 projections by 57%, and its 2024 projections by 42%. Additionally, as shown in Staff
13 Exhibit S-13.3, it was admitted in discovery that the Company has made errors in recent
14 reporting of benefits related to the CVR program.¹¹ Company witness Partlan's Figure 58
15 in direct testimony suggests that the Company had a cumulative peak MW reduction of
16 39.1 MW in 2023 and 51 MW in 2024 due to the CVR program. See Staff Exhibit S-13.3
17 for a discovery response stating that the 39.1 MW reduction in 2023 was just a projection,
18 and the actual data supports an 18.7 MW reduction, or less than half of the original
19 projection. Additionally, this discovery response states that the cumulative peak MW
20 reduction for 2024 was actually only 17.58 MW, as opposed to the 51 MW stated in Figure
21 58 of Company witness Partlan's direct testimony, or approximately one-third of the

¹¹ Exhibit S-13.3.

DIRECT TESTIMONY OF RYAN BOUTET
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PART II

1 original projection. To the Company's benefit, it is also evident that the Company
2 overperformed its projections for cumulative MWh reduction in 2024, achieving
3 approximately 190,000 MWh of reduction compared to the projected 120,000 MWh of
4 reduction. Staff would opine that the peak MW reduction metric benefit was over-projected
5 by a larger margin than the cumulative MWh reduction metric benefit was under-projected,
6 meaning that weighing the two metrics equally would suggest the Company is ultimately
7 not projecting its costs and benefits properly.

8
9 Q. What recommendation does Staff have for the CVR sub-program?

10 A. Staff recommends disallowances to the CVR sub-program such that the funding will be
11 reset to the Company's most recent 5-year historic average plus inflation. As stated in line
12 26, column (h) on page 1 of Company exhibit A-113, sponsored by Company witness
13 Michael Kelly, the current 5-year average for the CVR sub-program is \$3.166 million.
14 Utilizing the Company sponsored inflation rates of 2.1% for 2025, 2.4% for 2026, and
15 2.4% for 2027 results in a 12-month bridge period projected expenditure of approximately
16 \$3.232 million, a 4-month bridge period projected expenditure of approximately \$1.103
17 million, and a test year projected expenditure of approximately \$3.336 million. This math
18 is documented in Exhibit S-13.10. The associated disallowances range between 7.5% and
19 26%, which are notably lower than the percentages by which the Company has underspent
20 in the most recent 2 years, and are reasonable given that they align with the Company's 5-
21 year historic average spending.

DIRECT TESTIMONY OF RYAN BOUTET
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1 Q. What is the Company proposing for the LVD Lines Overloaded Equipment investment
2 category as part of the Capacity program?

3 A. In this case, the Company is proposing to spend \$21.365 million in the bridge period to
4 complete 125 units of work, and \$53.103 million in the test year to complete 278 units of
5 work, as presented in Figure 54 of Company witness Partlan's direct testimony.¹²

6
7 Q. Does Staff support the proposed expenditures for the Overloaded Equipment investment
8 category? If not, explain why.

9 A. No. The Company has not demonstrated that the test year expenditures are reasonable and
10 prudent, nor that the Company will be able to effectively scale up spending given current
11 year-to-date spending trends. As mentioned briefly in the beginning of my testimony, this
12 particular investment category faced scrutiny in the most recent rate case due to a seven-
13 fold increase in work projects between the bridge period and test year and a lack of support.
14 Staff opines that the Company is again proposing a large increase in work projects for this
15 investment category, similarly with a lack of support. The bridge period plan of 125 units
16 would equate to approximately 90 units annually, which is the number approved for the
17 test year by the Commission in its order in MPSC Case No. U-21585.¹³ The Company's
18 proposed 278 projects in the test year represent a three-fold increase in annual work
19 projects between the bridge period and the test year. Furthermore, a discovery response
20 contained in Exhibit S-13.4 shows that, for January through June of 2025, the Company
21 has only spent \$3.595 million on its LVD Lines Capacity sub-program (of which

¹² Direct Testimony of Jennifer Partlan, p. 116.

¹³MPSC Case No. U-21585 – Commission Order, March 21, 2025, p. 88.

DIRECT TESTIMONY OF RYAN BOUTET
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PART II

1 overloaded equipment is an investment category) of its initially projected \$21.435 million
2 in expenditures for 2025. If the Company continues at this rate, it will have spent
3 approximately \$7.19 million by the end of the year, or only 34% of its projection.
4

5 Q. What recommendation does Staff have for the Overloaded Equipment investment
6 category?

7 A. Staff recommends the Commission approve the proposed bridge year funding, as it
8 supports approximately 90 annual projects as recently approved in the order for MPSC
9 Case No. U-21585. Staff would further recommend that the Commission disallow
10 approximately \$18.72 million from the test year for this investment category, based on a
11 project-count reduction from the proposed 278 projects to 180 projects. This is still
12 permitting a doubling of the most previously approved pace for this investment category.
13 Staff opines that the Company did not provide enough new testimony or support for this
14 investment category to justify its proposed expenditures as being reasonable and prudent,
15 and that current year-to-date spending data does not suggest that the Company is able to
16 spend in this category as much as projected.
17

18 Q. What is the Company proposing for its LVD Zonal Health Improvements investment
19 category as part of the Reliability program?

DIRECT TESTIMONY OF RYAN BOUTET
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PART II

1 A. The Company is proposing to spend \$61.32 million in the bridge period on 497 work units,
2 and \$34.917 million in the test year for 175 work units, as referenced on Figure 35 within
3 Company witness Partlan's testimony.¹⁴

4
5 Q. Does Staff support the Company's proposal for the LVD Zonal Health Improvements
6 investment category? If not, explain why.

7 A. No. As mentioned at the start of my testimony, this investment category faced a large
8 disallowance in the most recent rate case due to a lack of complete cost information,
9 including historical costs, as this is a re-labeled investment category.¹⁵ Further, the
10 Commission went on to state that "[p]rior to approving a 500% increase in capital spending
11 for zonal health between the bridge period and test year, the Commission will want to see
12 more analysis of the most cost-effective opportunities to drive improvement in reliability
13 performance, using the results of the recent third-party audit in Case No. U-21305 as a
14 starting point."¹⁶ Staff acknowledges that the Company's testimony on this topic has
15 expanded to include specific examples of test period projects, as shown on page 48 of
16 Company witness Partlan's testimony. However, there is little discussion or analysis of the
17 most cost-effective approaches to improve reliability as asked for by the Commission. It
18 appears that Zonal Health projects are identified by the Company's Reliability Analytics
19 Engine (RAE); however, the discussion of this analytics engine suggests that it only ranks
20 Zonal Health projects against each other to determine prioritization of these projects. It is
21 not evident that the RAE considers other approaches outside of Zonal Health projects.

¹⁴ Direct Testimony of Jennifer Partlan, p. 69.

¹⁵ MPSC Case No. U-21585 – Commission Order, March 21, 2025, Page 62.

¹⁶ MPSC Case No. U-21585 – Commission Order, March 21, 2025, Page 63.

DIRECT TESTIMONY OF RYAN BOUTET
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PART II

1 Q. What recommendation does Staff have with regard to the Zonal Health Improvements
2 investment category of the Reliability program?

3 A. Staff is proposing a 4-month bridge period disallowance of \$3.69 million and a 12-month
4 bridge period disallowance of \$11.070 million. Staff supports the Company's proposed test
5 year expenditures, and, in fact, this bridge period adjustment will align annual spending
6 levels between the test year and the bridge period. Staff supports the Company's test year
7 expenditures as the result of a discovery response shown in Staff exhibit S-13.5, in which
8 the Company proves to have successfully spent \$34.243 million on this investment
9 category in 2024. Note that page 2 of Exhibit S-13.5 is only an excerpt from an excel file
10 provided in the Company's discovery response. It is reasonable to believe that the
11 Company can spend \$34.917 million in the test year if it was capable of nearly identical
12 expenditures last year. It would be reasonable to allow the Company to continue work at a
13 pace proven to be attainable in 2024 while awaiting further support and details regarding
14 the impacts of Zonal Health Improvements.

15
16 Q. What is the Company proposing for its Repetitive Outages sub-program as part of the
17 Reliability program?

18 A. The Company proposal includes a bridge period expenditure of \$21.089 million and a test
19 year expenditure of \$30.344 million.¹⁷
20

¹⁷ Direct Testimony of Jennifer Partlan, p. 78.

DIRECT TESTIMONY OF RYAN BOUTET
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1 Q. Does Staff support the Company's proposal for the Repetitive Outages sub-program? If
2 not, explain why.

3 A. No. In the most recent two rate cases, the Company has displayed significant amounts of
4 underspending in this sub-program. For calendar year 2023, the Company projected
5 spending \$9.587 million on its Repetitive Outages sub-program in MPSC Case No. U-
6 21389 as seen in line 13, column (i) of Staff exhibit S-13.1; however, in the subsequent
7 rate case, MPSC Case No. U-21585, the Company reported 2023 actual spending of \$4.082
8 million as seen in line 12, column (g) of Staff exhibit S-13.2, a 57% underspend. For
9 calendar year 2024, the Company projected spending \$9.856 million on its Repetitive
10 Outages sub-program in MPSC Case No. U-21585, as seen in line 12, column (i) of Staff
11 exhibit S-13.2. However, in this instant case the Company has reported 2024 actual
12 spending to be \$4.491 million as per line 12, column (g) in Company exhibit A-113, a 54%
13 underspend. The Company has not demonstrated it can successfully undertake its projected
14 spending when it has in recent history been unable to spend one-third of this projection
15 despite Commission approval.

16
17 Q. What recommendation does Staff have for the Repetitive Outages sub-program?

18 A. Staff is proposing a 20% disallowance to both the bridge period and test year projections
19 for the Repetitive Outages sub-program. In detail, this would be a \$2.002 million
20 disallowance to the 12-month bridge period, a \$2.215 million disallowance to the 4-month
21 bridge period, and a \$6.068 million disallowance to the test year. This proposal strikes a
22 compromise between the evident recent underspending by the Company and the

DIRECT TESTIMONY OF RYAN BOUTET
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1 recognition by the Commission in its Order in MPSC Case No. U-21585 that this sub-
2 program is valuable to the Company's CEMI-4 performance.¹⁸

3
4 Q. What does the Company propose for the Make-Ready work investment category as part of
5 the Asset Relocations program?

6 A. The Company's initial testimony filing was incorrect, as revealed in discovery shown in
7 Staff exhibit S-13.6. Referencing the discovery response, the Company's actual proposal
8 for this investment category is to spend \$45.837 million in the bridge period on 3,728 work
9 units, and \$39.265 million in the test year on 3,181 work units. This is the equivalent of a
10 \$12,295 unit cost in the bridge period, and a \$12,343 unit cost in the test year.

11
12 Q. Does Staff support the Company's proposal for the Make-Ready work investment
13 category? If not, explain why.

14 A. No. Staff does not support the Company projections for this investment category due to a
15 nearly 60% increase in unit costs when compared to the most recent approval for this
16 investment category in the previous rate case, MPSC Case No. U-21585. In MPSC Case
17 No. U-21585, the Commission approved the Company's projected test year expenditure of
18 \$7.302 million for 950 work units as seen in Staff exhibit S-13.7, which suggests a unit
19 cost of \$7,686. In the discovery response, it is stated that the proposed unit cost in this case
20 is commensurate with the actual unit costs in 2024. Indeed, it is seen on line 40 of page 2
21 of Exhibit A-130 that the 2024 actual unit costs were \$12,453. However, justification for

¹⁸ MPSC Case No. U-21585—Commission Order, March 21, 2025, p. 73.

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1 this steep increase over the U-21585 unit cost of \$7,686 is lacking within the Company
2 testimony, and it is incumbent upon the Company to provide evidence that such a cost
3 escalation is reasonable and prudent. Company witness Partlan's testimony that describes
4 the nature of make-ready work can be found on page 43 of direct testimony. Compared to
5 the description given by Company witness Donald Lynd in MPSC Case No. U-21585
6 shown in Staff exhibit S-13.8, it can be seen that the Company lists the same exact range
7 of construction activities necessary for Make-Ready work. Specifically, both witnesses
8 make the exact same statement: "Make-ready work can include a range of construction
9 activities, including but not limited to raising electric conductors and equipment, adding or
10 manipulating down guys, effectively grounding streetlight brackets, raising or lowering
11 existing communications attachments, and pole replacements."¹⁹ The majority of the work
12 functions described by the Company above, with the exceptions of pole replacements and
13 adding down guys, seemingly fit into a category of maintenance and/or modification work
14 of existing infrastructure, such as raising electric conductors, manipulating down guys,
15 grounding streetlight brackets, and adjusting existing communications attachments. The
16 Company has not demonstrated that unit-costs for an investment category seemingly
17 focused on maintenance and modification of existing equipment should be subject to such
18 large cost escalations, the scale of which has recently only been justified in categories
19 regarding purchases of new equipment that is facing heavy inflationary and/or supply chain
20 pressures, such as distribution transformers. A 60% increase in unit cost for this investment

¹⁹ Direct Testimony of Jennifer Partlan, p. 43.

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1 category is not supported in testimony, as the Company has not identified any material
2 ways in which the nature of work has changed.

3
4 Q. What does Staff recommend for the Make-ready work investment category?

5 A. Staff is recommending a disallowance based on a unit-cost adjustment, adjusted for
6 inflation. Starting with the previously approved test year unit cost of \$7,686, Staff applied
7 a 2.1% inflation adjustment for the 12-month bridge period to arrive at a unit cost of \$7,848.
8 Next, Staff applied a pro-rated 2.4% inflation adjustment for the 4-month bridge period to
9 arrive at a unit cost of \$7,911. Staff lastly applied another 2.4% inflation adjustment for
10 the test year to arrive at a test year unit cost of \$8,100. The 2.1%, 2.4%, and 2.4% inflation
11 adjustments are using the Company-sponsored inflation rates for 2025, 2026, and 2027,
12 respectively. This work is displayed in Staff exhibit S-13.10. This totals to a 12-month
13 bridge period disallowance of \$12.435 million, a 4-month bridge period disallowance of
14 \$4.086 million, and a test year disallowance of \$13.495 million.

15
16 Q. What is the Company proposing for the Right-of-Way investment category, as part of the
17 Reliability program?

18 A. The Company has proposed a bridge period expenditure of \$6.188 million, and a test year
19 expenditure of \$17.667 million, as seen in Figure 35 of Company witness Partlan's direct
20 testimony.

21
22 Q. Does Staff support the Company proposal for the Right-of-Way investment category? If
23 not, explain why.

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1 A. No. Staff does not support the Company’s test year projection for this investment category.
 2 The Company’s bridge period, when annualized, equates to \$4.641 million in spending per
 3 year, which happens to be the exact amount that the Company was allowed for the test year
 4 in its most recent rate case, MPSC Case No. U-21585. The Company had requested \$12
 5 million for its test year in MPSC Case No. U-21585 but was disallowed the sum of \$7.359
 6 million as suggested by the AG and adopted by the ALJ and Commission. The Order reads:
 7 “Lastly, the Attorney General contested the ROW category of spending within LVD Lines
 8 Reliability, citing a lack of detail regarding the link between projected costs and specific
 9 lines to address.”²⁰ The next page of the order states “The ALJ agreed with the Attorney
 10 General’s proposed disallowances of ... \$2.859 million in the bridge period and \$7.359
 11 million in the test year for ROW acquisitions.”²¹ Lastly in this section of the Order, it is
 12 stated that “[a]s to the Zonal Health Improvements and the ROW acquisition portions of
 13 LVD Reliability, the Commission finds the ALJ’s recommendation to be well-reasoned
 14 and supported by persuasive evidence on the record.”²² Staff has found a similar lack of
 15 detail regarding projected costs and specific lines or projects to link them to in this instant
 16 case. When asked for details about project specifics for the ROW category, the Company
 17 responded that there are no individual projects in the ROW category, and that costs are
 18 developed according to a percentage of the Targeted Circuit Improvements investment
 19 category, shown in Staff exhibit S-13.8. Staff opines that the Company has not responded
 20 to the need for more specific details regarding ROW projects and therefore does not support
 21 the Company’s test year projections.

²⁰ MPSC Case No. U-21585 – Commission Order, March 21, 2025, p. 55.

²¹ MPSC Case No. U-21585 – Commission Order, March 21, 2025, p. 56.

²² MPSC Case No. U-21585 – Commission Order, March 21, 2025, p. 62.

DIRECT TESTIMONY OF RYAN BOUTET
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1 Q. What does Staff recommend for the Right-of-Way investment category?

2 A. As previously mentioned, Staff supports the Company's bridge period proposals for the
3 ROW investment category, as they are based on previous test year approvals in MPSC
4 Case No. U-21585. Staff is proposing a test year expenditure in this case of \$4.891 million
5 based on inflation adjustments to the approved test year in U-21585. This new total was
6 arrived at by inflating the previous \$4.641 million cost by 2.1% for the 12-month bridge
7 period, a pro-rated 2.4% for the 4-month bridge period, and by 2.4% in the instant case's
8 test year. This math is documented in Staff exhibit S-13.9.

9
10 **Summary**

11 Q. Please summarize your recommendations.

12 A. 1. Staff recommends the following disallowances to the Conservation Voltage Reduction
13 sub-program:

14 - A 12-month bridge period disallowance of \$1,158,514.

15 - A 4-month bridge period disallowance of \$91,645.

16 - A test year disallowance of \$733,454.

17 2. Staff recommends the following disallowance to the Overloaded Equipment investment
18 category:

19 - A test year disallowance of \$18,720,000.

20 3. Staff recommends the following disallowances to the Zonal Health Improvements
21 investment category:

22 - A 12-month bridge period disallowance of \$11,070,000.

23 - A 4-month bridge period disallowance of \$3,690,000.

DIRECT TESTIMONY OF RYAN BOUTET
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1 4. Staff recommends the following disallowances to the Repetitive Outages sub-program:

2 - A 12-month bridge period disallowance of \$2,002,200.

3 - A 4-month bridge period disallowance of \$2,215,600.

4 - A test year disallowance of \$6,068,800.

5 5. Staff recommends the following disallowances to the Make-Ready Work investment
6 category:

7 - A 12-month bridge period disallowance of \$12,435,482.

8 - A 4-month bridge period disallowance of \$4,086,647

9 - A test year disallowance of \$13,495,815.

10 6. Staff recommends the following disallowance to the Right-of-Way investment category:

11 - A test year disallowance of \$12,775,998.

12
13 Q. Does this conclude your testimony?

14 A. Yes.

1 MR. SONNEVELDT: Next, your Honor, Staff moves
2 to bind in the direct and rebuttal testimony of Jessica
3 Duell. Her direct testimony consists of a cover sheet and
4 25 pages of questions and answers. Her rebuttal testimony
5 consists of a cover sheet and three pages of questions and
6 answers, and in that, she -- in those -- that testimony
7 she sponsors Exhibits S-18 and S-20.

8 JUDGE THOITS: Are there any objections to the
9 admission of this testimony or these exhibits?

10 Hearing none. The direct and rebuttal testimony
11 of Jessica Duell is bound into the record, and Exhibits S-
12 18 and S-20 are admitted.

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 generation and distribution of electricity and for other relief. 	))))))	Case No. U- 21870

QUALIFICATIONS AND DIRECT TESTIMONY OF

JESSICA DUELL

MICHIGAN PUBLIC SERVICE COMMISSION

September 30, 2025

QUALIFICATIONS OF JESSICA DUELL
CASE NUMBER U-21870
PART I

1 Q. Please state your full name and business address for the record.

2 A. My name is Jessica Duell (she/her/hers), and my business address is 7109 West Saginaw
3 Highway, Lansing, Michigan 48917.

4 Q. By whom are you employed and in what capacity?

5 A. I am employed by the Michigan Public Service Commission (MPSC or Commission) as a
6 Public Utilities Departmental Analyst in the Electric Operations Section of the Energy
7 Operations Division.

8 Q. Please describe your educational background.

9 A. I earned a Bachelor of Liberal Arts with a major in Biology and minor in psychology at
10 Olivet College in 2015.

11 Q. What is your professional background?

12 A. In 2015 I worked as a certified nurse assistant (CNA) at Green Acres of Ionia in Ionia,
13 Michigan. As a CNA, I would take care of patients with their daily needs. In 2016, I
14 started working for the State of Michigan Department of Health and Human Services
15 (MDHHS) at the Hawthorn Center as a Childcare Worker. My responsibilities were to
16 watch over the children and take care of them while they stayed at the hospital. I worked
17 at the Hawthorn Center until January of 2018 when I then transferred to become an
18 Eligibility Specialist for MDHHS. I worked as an Eligibility Specialist from 2017-2022.
19 As an eligibility specialist I had to work with policy and procedures to determine each
20 client's eligibility for state benefits. I would process applications, conduct reviews,
21 interview clients, speak to clients on the phone, and process verifications received to
22 determine eligibility for each program. I would also contact utility companies when a
23 client's utilities were turned off or in shut-off status. I would communicate with the

QUALIFICATIONS OF JESSICA DUELL
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PART I

1 utilities to figure out how much the client owed and to determine what I could do to get
2 the client's utility service turned back on or not shut off, depending on the circumstances.
3 Clients would submit an SER (State Emergency Relief) application and I would then
4 have to process the application to prevent a shut off of their utilities. I also worked as a
5 mentor for new workers. My responsibilities as a mentor were to train new workers in
6 every aspect of the job and make sure they could complete the job precisely and
7 accurately. In February of 2022, I left MDHHS and started working at the MPSC in
8 Electric Operations as Departmental Analyst.

9 Q. Have you received any work-related training since starting your employment with the
10 MPSC?

11 A. Yes. The trainings I have completed so far include:

- 12 • FEMASID Training
- 13 • Introduction to Incident Command System, ICS-100
- 14 • Basic Incident Command System for Initial Response ICS-200
- 15 • An Introduction to the National Incident Management System
- 16 • National Response Framework, An Introduction,
- 17 • MI CIMS (WebEOC) End-User Training,
- 18 • Multicultural Self-Awareness,
- 19 • NRRI-RTI Training
- 20 • The Basics for the Electric Industry
- 21 • Root Cause Training
- 22 • MIC AM Champion

QUALIFICATIONS OF JESSICA DUELL
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PART I

- Fundamentals of Overhead Distribution Systems
- Introduction to Substation Design
- Underground Electric Distribution Fundamentals
- Electric Distribution Safety
- NARUC/NASEO & LBNL Distribution System Planning
- Integrated Right-of-Way Vegetation Management
- NARUC RTI - The Basics of Utility Accounting and Ratemaking 2024
- Rate Case Basics 2024
- IPU Grid School
- MSU IPU Fundamentals

•

Q. Have you previously testified before the Commission?

A. Yes. I have filed testimony in the following cases:

<u>Case No</u>	<u>Company</u>	<u>Type of Case</u>	<u>Subject of Testimony</u>
U-21286	UPPCO	Electric Rate	Tree Trim and Facilities
U-21297	DTE	Electric Rate	Tree Trim, Streetlighting, Service Restoration
U-21389	Consumers	Electric Rate	Line Clearing, Streetlighting, Service Restoration
U-21555	UPPCO	Electric Rate	Distribution Capital Expenditures
U-21534	DTE	Electric Rate	Tree Trim, Streetlighting, Service Restoration
U-21585	Consumers	Electric Rate	Line Clearing, Streetlighting, Service Restoration
U-21860	Consumers	Electric Rate	Tree Trim and Service Restoration

DIRECT TESTIMONY OF JESSICA DUELL
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PART II

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

2 A. The purpose of my testimony is to present the Michigan Public Service Commission
 3 Staff's (Staff) recommendations regarding Consumers Energy Company's (Consumers
 4 Energy, Consumers, or the Company) Line Clearing, Streetlighting, and Service
 5 Restoration programs.

6 Q. Are you sponsoring any exhibits?

7 A. Yes, I am sponsoring exhibits with my direct testimony.

8 Exhibit No. Description

9 Exhibit S-18 Consumers Energy's response to Staff discovery U21870-ST-CE-0191

10 Exhibit S-18 Consumers Energy's response to Staff discovery U21870-ST-CE-0117

11 Exhibit S-18 Consumers Energy's response to Staff discovery U21870-ST-CE-0116

12 Exhibit S-18 Consumers Energy's response to Staff discovery U21870-ST-CE-0131

13 Exhibit S-18 Consumers Energy's response to Staff discovery U21870-ST-CE-0269

14 Exhibit S-18 Consumers Energy's response to Staff discovery U21870-ST-CE-0109

15 **Line Clearing Expenses**

16 Q. Please briefly describe the Company's Line Clearing program.

17 A. Company witness Sara Stewart explains Consumers' line clearing program on page 3,
 18 lines 16-27 of direct testimony:

19 The Company's Line Clearing Program is responsible for maintaining clearance
 20 between vegetation and energized equipment and to eliminate vegetation
 21 hindering accessibility to the Company's electric lines. The Company uses
 22 Integrated Vegetation Management ("IVM") along the Company's electric line
 23 rights-of-way to accomplish these objectives. IVM is the practice of promoting
 24 compatible plant communities along rights-of-way using a combination of cost-
 25 effective methods, including chemical, cultural, mechanical, or manual
 26 treatments. This work is performed by contractors with qualified line clearance
 27 tree trimmer employees, in accordance with Michigan Occupational Safety and

DIRECT TESTIMONY OF JESSICA DUELL

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PART II

1 Health Administration (MIOSHA) requirements, on production-oriented contracts
2 with the Company. The Line Clearing Program is divided into two parts: (i) High
3 Voltage Distribution ("HVD") Line Clearing; and (ii) Low Voltage Distribution
4 ("LVD") Line Clearing.

5
6 Consumers divides its line clearing program into two subprograms: HVD and LVD line
7 clearing. HVD line clearing operates on a 4-year clearing cycle and LVD line clearing
8 will operate on a 5-year clearing cycle. Consumers explains their LVD line clearing
9 process on page 6, lines 11-18 of Company witness Stewart's direct testimony:

10 LVD Line Clearing manages vegetation along LVD primary voltage systems and
11 secondary voltage systems, including service conductors. The Company clears
12 vegetation within a 30-foot-wide right-of-way for primary voltages to attain a
13 minimum of 10 feet of separation between conductors and vegetation at the time
14 of clearing and to maintain accessibility along the right-of-way for maintenance
15 and repair of the line. As a part of LVD line clearing, hazard trees, such as dead or
16 dying trees that are within 20 feet of the edge of the right-of-way that are
17 accessible to aerial lift trucks, are removed when not objected to by the property
18 owner.

19
20 Consumers explains its HVD line clearing process on page 4, lines 2-10 of Company
21 witness Stewart's direct testimony:

22 HVD Line Clearing manages vegetation along the Company's high voltage
23 systems. There are two major voltages on the Company's HVD system: 46
24 kilovolts ("kV") and 138 kV. The Company clears vegetation within an 80- to
25 120-foot-wide right-of-way for these voltages to attain a minimum of 15 feet of
26 separation for 46 kV lines and 20 feet of separation for 138 kV lines between
27 conductors and vegetation at the time of clearing. The Company also manages
28 vegetation within the right-of-way to maintain accessibility along the right-of-way
29 for maintenance and repair of the line. During scheduled maintenance line
30 clearing, the Company identifies and removes hazard trees up to 40 feet from the
31 edge of the right-of-way.

32
33 The Company's vision for line clearing is to have fewer tree-caused outages on their
34 system which will improve electric reliability for their customers. The Company is
35 proposing to ramp up their LVD line clearing cycle to 5-years and perform more
36 aggressive line clearing on targeted three phase primary lines. The Company plans to

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1 complete both shortened cycle and more aggressive line clearing by the end of the 2030-
2 2031 period. Also, the Company is proposing an LVD tree-caused outage review
3 program which will perform a deeper analysis of tree-caused outages.

4 Q. Please describe the Company's proposal to ramp up their LVD line clearing cycle to 5-
5 years.

6 A. The Company explains the ramp up to a 5-year line clearing cycle on page 16, lines 8-15
7 of Company witness Stewart's direct testimony:

8 The five-year cycle strategy describes clearing one-fifth of the Company's LVD
9 line miles annually in steady-state cycle maintenance while maintaining the
10 standard that all LVD circuits have been fully cleared within a five-year period.
11 The Company's proposal includes a ramp-up strategy to eliminate all backlog
12 miles (circuits that have not been fully cleared within five years) by the end of the
13 2030-2031 test period. During this ramp-up period, the Company proposes to
14 utilize its forestry workplan selection tool to inform the sequencing of backlog
15 reduction based on its optimization outputs for reliability and safety risk.
16

17 Q. Did Staff review Company's proposed test year Line Clearing expenditures?

18 A. Yes, Staff reviewed the Company's proposed projected test year line clearing spending of
19 \$186,684,000 in O&M expenses. This amount can be found in Exhibit A-170 (SES-1),
20 line 24, column (q).

21 Q. Does Staff support the Company's requested \$186,684,000 O&M expense for line
22 clearing for the projected test year?

23 A. Yes, Staff supports the requested \$186,684,000 for the projected test year O&M expense.
24 It is crucial to allow Consumers to spend the full amount for line clearing to increase the
25 resiliency of Consumers Energy's electric distribution system.

26 Q. Please explain the Company's proposal to recover their LVD line clearing O&M
27 spending in the test period as a regulatory asset.

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A. Company witness Stewart explains on page 48, lines 8-13:

Yes, the Company is proposing regulatory asset treatment for the funding requirement for the test period above baseline expenditures, identified in Exhibit A-170 (SES-1), column (p), line 27. Figure 23 below summarizes the total O&M expense, baseline expense, and regulatory asset proposal amounts for the test period. This proposed alternate funding mechanism is discussed in further detail in Company witness Daly's testimony on page 34, line 18, through page 36, line 20.

FIGURE 23
LINE CLEARING O&M ALTERNATE FUNDING MECHANISM
PROPOSAL TEST PERIOD

Description	HVD	LVD	Total
Total O&M Expense	\$11,839,660	\$174,844,314	\$186,683,974
Baseline Expense	\$11,839,660	\$152,606,207	\$164,445,867
Regulatory Asset	\$0	\$22,238,107	\$22,238,107

Q. Does Staff support the Company's proposal to recover LVD line clearing O&M spending in the test period as a regulatory asset?

A. Yes, Staff supports the Company's proposal to recover LVD line clearing O&M spending in the test period as a regulatory asset. Staff recommends the rate of return be at Staff's Short Term Debt Rate of 4.92% and not the Company's pre-tax weighted average cost of capital ("pre-tax WACC"). The Commission has approved historically a regulatory asset for DTE Electric's tree trimming surge program, so Consumers should be allowed the same treatment.

Q. Please explain why Staff chose their own Short Term Debt Rate over the Company's pre-tax WACC.

A. Staff chose their own Short Term Debt Rate over the Company's pre-tax WACC because the Company has shown they have not invested in line clearing like they should have and has continued to operate on longer cycle lengths than other peer utilities. The Company

DIRECT TESTIMONY OF JESSICA DUELL
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operated on a 14.2 year line clearing cycle until 2020. On December 12 of that year, the Commission approved all requested line clearing funding in MPSC Case No. U-20697 so the Company could move to a 7-year effective line clearing cycle¹. In MPSC Case U-21585 the Commission ordered the Company to “consider the benefits of shifting to a four-year fixed tree trimming cycle based on the findings of its Formal Optimization Analysis of Line Clearing Cycles into its forestry line clearing operations and maintenance approach and spending proposal”². In Staff’s opinion, the Company did not follow the Commission request and perform an analysis of a four-year cycle separate from the Optimization Analysis, but instead proposed shifting their line clearing effective cycle length to 5-years. In the instant case, Exhibit A-173 (SES-4) pages 1-6 show the Company’s 2025 LVD line clearing work plan. The Company lists 283 circuits and when these circuits were last cleared. Staff counted circuits that were last cleared 20 years ago or more and found that, out of the 283 circuits listed, 77 of them were last cleared 20-37 years ago and 42 circuits were last cleared 30-37 years ago. Staff is astonished at these numbers and how the Company has allowed circuits not to be cleared in 37 years. Staff’s opinion is the Company did not prioritize their line clearing program highly enough in the past which warrants the return on the line clearing regulatory asset to be set at Staff’s short term debt rate.

Line Clearing Recommendations

Q. Please explain in detail the Company’s testimony regarding overhang removal in the first zone (everything up to the first protective device).

¹ U-20697 order, December 12, 2020, p.180 & 181.

² U-21585 order, March 21, 2025, p. 436

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1 A. Company witness Stewart explains the Company's overhang removal in the first zone on
2 page 8, lines 20-23 of direct testimony:

3 First zones are currently cleared to the same specifications as program
4 maintenance with the exception that individual trees with overhanging branches
5 regardless of clearance above conductors have been considered for 100% removal
6 of these overhanging branches.
7

8 Q. Please provide the Company's discovery response regarding overhang removal in the
9 first zone.

10 A. Company witness Stewart explained in discovery response U21870-ST-CE-0191, which
11 is shown in Staff Exhibit S-18, pages 7 and 8:

12 Canopy removal in the first zone is currently determined on an individual tree
13 basis, as discussed in my direct testimony on page 8, lines 20 through 23. The
14 Company determines which limbs within tree canopies to remove depending on
15 multiple factors to mitigate risk of limb failure resulting in customer outages,
16 including but not limited to: health of the tree, characteristics of the species such
17 as if it is a hard wood or a soft wood, maturity of the tree/limbs, and location of
18 the tree/limbs relative to the conductors. If, these factors considered, a limb is
19 determined to be sound at the time of inspection and not a current risk to outage,
20 the limb is not targeted for removal. As stated above, the Company does not track
21 data on these individual instances of select canopy or partial canopy removal.
22

23 Q. Does Staff have any recommendations regarding the Company's first zone canopy
24 removal program?

25 A. Yes, Staff recommends the Company clear all canopy in the first zone. The Company
26 currently determines canopy removal in the first zone on a case-by-case basis. This
27 means the Company is not clearing 100% of tree canopy in the first zone. Other utility
28 companies, like DTE, clear 100% of tree canopy in the first zone. Staff's opinion is that
29 Consumers would see a decrease in tree caused outages if the Company were to start this
30 practice. Customers deserve reliable service and line clearing is a crucial part of making

DIRECT TESTIMONY OF JESSICA DUELL
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1 this happen. The Company needs to deploy resources and modify their current practices
2 to allow for more reliable service for their customers.

3 Q. Please explain the Company's proposal for more aggressive removal of overhang in
4 everything past the first zone.

5 A. Company witness Stewart explains the Company's proposal of overhang removal on
6 page 23, lines 2-7 of direct testimony:

7 The Company is proposing canopy removal on 10% or roughly 5,500 miles of
8 overhead primary, targeting the three phase portions of circuits that have the
9 highest consequence of failure due to serving the most downstream and/or critical
10 customers. Decreasing the risk of tree-caused outages along this targeted three
11 phase primary increases the availability and enablement of manual and automatic
12 switching capabilities, reducing the impact of outages that may occur regardless
13 of cause.

14
15 Q. Does Staff support the Company's proposal for overhang removal in everything past the
16 first zone?

17 A. Yes, Staff supports the Company's proposal of removing 10% or roughly 5,500 miles of
18 three phase overhead primary tree overhang in everything outside of the first zone. Staff
19 would like to re-iterate to the Company that it's extremely important it changes its line
20 clearing specifications to 100% removal of overhang in the first zone. With these two
21 changes to Consumer's line clearing specifications the Company will see improvements
22 in reliability for their customers.

23 Q. Is there any discrepancy between Company testimony and the Company's discovery
24 response regarding overhang removal in the first zone?

25 A. Yes, Staff analyzed the Company's testimony versus discovery response received
26 regarding removal of canopy in the first zone and found that the Company does not

DIRECT TESTIMONY OF JESSICA DUELL
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PART II

1 remove 100% of canopy in the first zone. In direct testimony on page 8, Company
2 witness Stewart stated:

3 Canopy removal in the first zone is currently determined on an individual tree
4 basis, as discussed in my direct testimony on page 8, lines 20 through 23. The
5 Company determines which limbs within tree canopies to remove depending on
6 multiple factors to mitigate risk of limb failure resulting in customer outages,
7 including but not limited to: health of the tree, characteristics of the species such
8 as if it is a hard wood or a soft wood, maturity of the tree/limbs, and location of
9 the tree/limbs relative to the conductors. If, these factors considered, a limb is
10 determined to be sound at the time of inspection and not a current risk to outage,
11 the limb is not targeted for removal. As stated above, the Company does not track
12 data on these individual instances of select canopy or partial canopy removal.
13

14 Company witness Stewart relies on the word “considered” as a basis point to state that
15 100% of canopy removal is looked into but may not happen for the entirety of zone 1.
16 Staff interpreted Company witness Stewart’s testimony as stating the Company removed
17 all canopy in the first zone 100% of the time, but after reviewing discovery responses
18 found this is not the case. This is an example of the Company not being clear and detailed
19 when providing testimony. Staff would like to see Company witnesses be clearer and
20 more detailed when writing testimony for future rate cases.
21

22 Q. Does Staff have any further recommendations regarding the Company’s line clearing
23 program?

24 A. Yes, Staff recommends the Company spend the entire amount of line clearing expenses
25 approved in each rate case they file and complete all line miles that are being proposed to
26 be trimmed each year. Staff compared the last rate case, MPSC Case No. U-21585, with
27 the instant case and found that the Company underspent in line clearing in 2024 and
28 cleared fewer miles than what was proposed and approved for 2024. In its rate case

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MPSC Case No. U-21585 the Company projected spending \$105,371,000 on LVD line clearing in 2024. In the current rate case, per Exhibit A-170 (SES-1) line 12, Column H, the Company actually spent \$99,494,748 in 2024 for LVD line clearing. When the Company was asked by Staff where the \$5,876,252 in remaining funding was allocated to, the Company did not answer the question. Please see discovery response U21870-ST-CE-0116, shown in Exhibit S-18, page 1. The Company projects certain amounts in different programs they are requesting in each rate case. It is extremely important that the Company explain where underspend amounts in certain programs are being reallocated to when asked. If the Company cannot provide Staff with detailed information regarding where unspent funds are being reallocated to then Staff may recommend disallowances in future rate cases.

Q. Did the Company explain why they cleared fewer miles in 2024 than what was proposed?

A. Yes, in discovery response U21870-ST-CE-0117, shown in Staff Exhibit S-18, page 9, Company witness Stewart stated:

The Company's projected 6,760 miles of LVD line clearing was estimated prior to execution of new LVD contracts in May 2024. The impact of the new LVD line clearing contracts is discussed in my direct testimony on page 47, lines 21 through 22, and page 48, lines 1 through 2. Higher unit costs per mile resulted in fewer O&M miles cleared for the budget amount. Additionally, the Company made operational decisions during the 2024 calendar year that resulted in less spend toward line clearing for the calendar year while still meeting its test year spend target toward line clearing as defined in the Order for MPSC Case No. U-21389.

Q. Does Staff have any concerns regarding the Company clearing fewer miles and experiencing contractor shortages?

A. Yes, Staff is concerned that the Company is clearing fewer miles than planned due to experiencing contractor shortages. Line clearing is one of the most important programs in

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any electric company's portfolio. If the Company is experiencing contractor shortages, Staff is concerned that this will cause the Company's proposal for a 5-year line clearing cycle to be achieved beyond the 2030/2031 deadline. It is extremely crucial that the Company increase their contracting crews for line clearing. The Company is already behind on their line clearing program, and Staff does not want to see the Company fall even further behind due to contractor shortages.

Q. Did the Company conduct a new analysis that considers the benefits of shifting to a 4-year fixed line clearing cycle as was ordered by the Commission in Case U-21585?

A. No, the Company did not provide a new analysis that considered the benefits of shifting to a fixed 4-year line clearing cycle. Company witness Stewart explains in direct testimony on page 32, lines 13-21:

Yes, the Company has considered the costs and benefits of shifting to a four-year fixed line clearing cycle, and it asserts that the prudent next step in the evolution of its Line Clearing Program is the outlined five-year line clearing cycle, continuing to prioritize residential customer cost-benefit. The Company has compared the estimated costs and projected benefits of achieving a four- and five-year line clearing cycle in the same ramp-up strategy period of this test period through the 2030-2031 test period. The Company estimates that achieving a four-year cycle in the same timeframe could raise expenses nearly 15% overall, with some years as high as 23%. In its comparison, the Company assumed a 0% change in expenses in this test period as it has projected the most aggressive crew resourcing plan it believes it can achieve in the first year. The Company estimates that this increased spending could result in only 3% additional reliability benefit across multiple metric types due to diminishing returns.

Company witness Stewart goes on to state on page 33, lines 4-13 of direct testimony that to increase line clearing miles the majority of the expense is due to increasing out-of-state crewing. The Company did not provide a new analysis to the Commission that provides information regarding associated costs, timing, and/or reliability improvements by moving towards a four-year cycle. The Company relies on the formal optimization

DIRECT TESTIMONY OF JESSICA DUELL
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PART II

analysis of line clearing cycles report, which was provided in Exhibit A-176 (SES-6) (also filed in MPSC Case U-20697), to determine if a four-year effective line clearing cycle is efficient or not. Staff expected the Company to provide a new dedicated analysis of a four-year line clearing cycle in their next filed rate case, which should have been the instant case, as requested by the Commission. Staff recommends the Company file a new analysis of the costs and benefits of a four-year cycle with its next rate case. In the analysis Staff would like the Company to provide an O&M exhibit sheet showing the costs of moving to a 4-year cycle, provide contractor costs associated with moving towards a 4-year effective cycle, provide detailed information on the availability and securing contracts for line clearing contractors with a 4-year cycle, and cost savings associated with moving towards a 4-year effective line clearing cycle.

Streetlighting Recommendations

Q. Does Staff have recommendations regarding Consumers' streetlighting program?

A. Yes, Staff recommends that the Company be more descriptive and detailed when replying to discovery questions sent by Staff. In discovery response U21870-ST-CE-0131, shown in Staff exhibit S-18, page 2, Staff had asked the Company where the remaining \$1,056,000 in spend for streetlighting had gone for year 2024. The Company replied to Staff, stating:

At the time of filing U-21585 in May 2024, the Company expected to spend \$19,597,000. This was an increase from the amount approved for the test year in U-21389 where the Company was approved to spend \$13,464,000 for the test year. The increase in the forecasted spend was driven by an expectation of higher failures that did not materialize but were in excess of what was approved. It is important to note that the Company's overall total distribution capital investment remains aligned with, or even exceeds, the amounts approved by the Commission.

DIRECT TESTIMONY OF JESSICA DUELL
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1 The Company's total 2024 distribution capital spending (\$920,439,000) exceeded
2 the 2024 portion of the bridge period that was projected (\$807,911,000) in case
3 No. U-21585.
4

5 This response does not give Staff any information on why the Company underspent in
6 streetlighting for 2024 and where the remaining \$1,056,000 in spend was allocated to. In
7 MPSC Case No. U-21585 the Commission ordered the Company to "provide the
8 Commission Staff with as much detail as possible regarding the application of excess
9 funds for streetlighting". Unfortunately, the Company did not follow the order. Staff
10 urges the Company to continue to be transparent and give as much detail as possible
11 when discussing where unspent expenses are being used and allocated to. Staff
12 recommends the Company keep track of their underspend in programs related to
13 distribution expenditures. If the Company were to underspend in any program they are
14 requesting in a rate case the Company could then provide Staff detailed information on
15 where those underspent expenses were allocated or shifted to when such information is
16 requested. If the Company cannot provide Staff with detailed information regarding
17 where unspent funds are being reallocated to then Staff may recommend disallowances in
18 future rate cases if insufficient information is being provided.
19

Service Restoration Expenses

20
21 Q. Please explain what programs are included in the Company's Service Restoration
22 Expenses.

23 A. Service restoration expenses are broken out into four categories in Company witness
24 Andrew Snider's testimony: service restoration O&M, service restoration resiliency fund,

DIRECT TESTIMONY OF JESSICA DUELL
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PART II

extraordinary storm accounting, technology enhancements and control/dispatch center consolidation.

Service Restoration

Q. Please briefly describe the Company's service restoration expenses.

A. Company witness Snider explains Consumers' service restoration program on page 3, lines 13-19 of direct testimony:

Following service interruptions, the Company is committed to restoring service to customers quickly and safely, regardless of the weather. Service restoration activities play a critical role in the timely restoration of service to customers during outages. Timely recovery of service restoration expense is essential to ensure resources are available to restore service as quickly as possible, as the Company will be challenged to achieve further improvements in storm restoration service if it does not have timely rate recovery for the costs associated with such service.

The main purpose of the service restoration program is to restore electric service to customers in a timely and efficient manner. It is important that the Company uses all available resources to make sure its customers do not have to suffer without electricity, particularly during the cold and hot months of the year.

Q. Did Staff review the Company's projected test year service restoration O&M expense?

A. Yes, Staff reviewed the Company's projected test year service restoration O&M expenses of \$165,200,000. This amount can be found in Exhibit A-107 (MPK-15), column (f), line 22.

Q. Does Staff support the Company's requested \$165,200,000 in service restoration projected test year O&M expense?

A. Yes, Staff recommends approval of \$165,200,000 for the projected test year service restoration O&M expense.

DIRECT TESTIMONY OF JESSICA DUELL
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PART II

Service Restoration Resiliency Fund

Q. Please briefly describe the Company's Service Restoration Resiliency Fund.

A. Company witness Snider explains the Service Restoration Resiliency Fund on page 23, lines 19-24 of direct testimony.

The Resiliency Fund ensures that every customer dollar allocated for service restoration is used for service restoration or returned to customers as a credit. The Resiliency Fund is a reserve of surplus service restoration dollars from any prior year that will be used as the first source of funds when actual costs for service restoration exceed base spend levels. The fund will be capped at \$30.7 million in the test year, with any dollars exceeding those levels refunded to customers through a bill credit.

Q. Does Staff support the Company's request for a Service Restoration Resiliency Fund?

A. No, Staff does not support the Service Restoration Resiliency Fund. This mechanism should not be approved because: 1) Staff is supporting the full service restoration expense for the test year; 2) the Commission rejected other service restoration mechanisms in prior cases (U-20963, U-20697, U-21389, and U-21585); 3) Staff's position is that customers will not see any benefit from this proposal due to the increase in storm restoration expenses in the past five years; 4) instead of putting unspent storm restoration expenses into a pool the Company could re-allocate the expenses to other distribution programs to further improve reliability; 5) the Company can request deferred accounting for any catastrophic storm that crosses their service territory in any year, as recently they did in MPSC Case No. U-21914.

Control/Dispatch Center Consolidation

DIRECT TESTIMONY OF JESSICA DUELL
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PART II

1 Q. Please briefly describe the new proposal for the Company's Control/Dispatch Center
2 Consolidation project.

3 A. Company witness Snider describes the new proposal for the Company's Control/Dispatch
4 Center consolidation project on page 38, lines 4-8 of direct testimony.

5 During the execution phase, it was identified through employee feedback that
6 there was a risk of losing talent and that operational capabilities would be
7 enhanced by staffing the back-up location, rather than maintaining an unstaffed
8 back-up location. While the decision to staff the back-up location provides a
9 better level of service and equitable cost avoidance, and SAIDI savings, it has
10 changed the scope of the project.
11

12 Company witness Snider states in direct testimony on page 38, lines 11-22 that staffing a
13 back-up location will significantly boost operational capabilities and provide a reliable
14 contingency plan if disruptions were to occur at other sites.

15 Q. Did Staff review the Company's capital expenditures for the bridge period 4 months
16 ending 04/30/2026 for the Control/Dispatch Center?

17 A. Yes, Staff reviewed the Company's proposed capital expenditures of \$4,871,000 for the
18 Control/Dispatch Center for this time period. This amount can be found in Exhibit A-102
19 (QAG-3) page 1, lines 25 and 26.

20 Q. Does Staff support the Company's requested \$4,871,000 for the bridge period (the 4
21 months ending 4/30/2026) for the Control/Dispatch Center?

22 A. No, Staff recommends a disallowance of \$2,435,500, half of the proposed expenditure for
23 the bridge period. Staff reviewed the Control/Dispatch Center project and, in MPSC Case
24 No. U-21585, the Company projected spending \$4,400,000 in 2024³. In the instant case,

³ Case U-21585 Exhibit A-82 (QAG-3) Pg. 1 Line 26.

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1 the Company stated they spent \$2,406,000 in 2024⁴. Since the Company underspent by
2 nearly half of what was requested and included in the calculation of rates previously,
3 Staff recommends disallowing half of what the Company is requesting for the bridge
4 period.

5 Q. Did Staff review the Company's projected test year capital expenditures for the
6 Control/Dispatch Center?

7 A. Yes, Staff reviewed the Company's proposed \$15,497,000 expenditure in the projected
8 test year for the Control/Dispatch Center. This amount can be found in Exhibit A-102
9 (QAG-3) page 1, lines 25 and 26.

10 Q. Does Staff support the Company's requested \$15,497,000 for the Control/Dispatch
11 Center for the projected test year?

12 A. No, Staff recommends a disallowance of \$7,748,500. Staff recommends disallowing half
13 of the expenditures for the projected test year. Staff reviewed the Control/Dispatch
14 Center project and, in MPSC Case No. U-21585, the Company projected spending
15 \$4,400,000 in 2024⁵. In the instant case, the Company stated they spent \$2,406,000 for
16 year 2024⁶. Since the Company underspent by nearly half of what was requested and
17 included in the calculation of rates previously, Staff recommends disallowing half of
18 what the Company is requesting for the projected test year.

19 **Service Restoration Artificial Intelligence Project**

20 Q. Please explain the Company's Artificial Intelligence Project.

21 A. Company witness Snider states on page 33, lines 6-12 of direct testimony:

⁴ Case U-21870 Exhibit A-102 (QAG-3) Pg. 1 Lines 25 & 26.

⁵ Case U-21585 Exhibit A-82 (QAG-3) Pg. 1 Line 26.

⁶ Case U-21870 Exhibit A-102 (QAG-3) Pg. 1 Lines 25 & 26.

DIRECT TESTIMONY OF JESSICA DUELL
CASE NUMBER U-21870
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The Company has developed several use cases where machine learning and AI can assist with faster and more consistent decision-making. Speed to execution is of critical importance during restoration events, and AI's unique availability to simultaneously evaluate multiple datasets and assist with decision-making will reduce non-value-added time during restoration. Furthermore, AI's learning abilities enable decision-making to continuously improve, are unaffected by turnover, and mitigate learning curves as people transition from role to role.

Company witness Snider states that the AI project will assist with storm declarations, resource planning, resource utilization or crew movements, and asset identification.

Company witness Snider also claims the AI project will reduce medium to catastrophic events by 4 hours with an estimated savings of \$4.5 million annually in storm restoration expenses.

Q. Did Staff review the Company's proposed capital expenditures for the Artificial Intelligence Project in the bridge period?

A. Yes, Staff reviewed the Company's proposed capital expenditures of \$1,370,000 for the Artificial Intelligence Project for this time period. This amount can be found in Exhibit A-12 (SHB-4) page 1, line 3.

Q. Does Staff support the Company's requested \$1,370,000 for the Artificial Intelligence Project in the bridge period?

A. No, Staff is recommending a disallowance in this category of \$31,082 for the bridge period.

Q. Why is Staff recommending a disallowance to the bridge period for the Artificial Intelligence Project?

A. Staff is recommending this disallowance because the Company discovered when replying to Staff's discovery question U21870-ST-CE-0269 that they miscalculated the Non-

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1 Labor other expense in both the bridge period and projected test year for the Artificial
2 Intelligence Project. See Staff exhibit S-18, pages 3 and 4.

3 Q. Did Staff review the Company's proposed capital expenditures for the Artificial
4 Intelligence Project in the projected test year?

5 A. Yes, Staff reviewed the Company's proposed capital expenditures of \$6,123,000 for the
6 Artificial Intelligence Project in this time period. This amount can be found in Exhibit A-
7 12 (SHB-4) page 1, line 3.

8 Q. Does Staff support the Company's requested \$6,123,000 for the Artificial Intelligence
9 Project in the projected test year?

10 A. No, Staff is recommending a disallowance of \$56,805 for the projected test year in this
11 category.

12 Q. Why is Staff recommending a disallowance to the projected test year for the Artificial
13 Intelligence Project?

14 A. Staff is recommending this disallowance because the Company discovered when
15 replying to a discovery question that they miscalculated the Non-Labor other expense for
16 both the bridge period and projected test year for the Artificial Intelligence Project, as
17 discussed previously.

18 **Wiredown Response Recommendations**

19 Q. Please explain the Company's wire down procedure.

20 A. Company witness Snider explained the Company's wire down procedure in discovery
21 response U21870-ST-CE-0109, shown in Staff exhibit S-18, pages 5 and 6:

22 Upon receiving a wire down ticket, the Operator assesses the location and
23 identifies the nearest available field resource. Key details from the wire down
24 ticket are communicated to the field resource. The assigned field resource arrives

DIRECT TESTIMONY OF JESSICA DUELL
CASE NUMBER U-21870
PART II

on site and immediately addresses any safety concerns to secure the area and mitigate risk to the public and emergency responders. The first responder will either make the situation safe or stand by until support arrives. If the wire down cannot be fully resolved during the initial response—due to additional hazards or the need for more personnel, the Operator coordinates and dispatches the appropriate field resources and external resources to complete the work safely. During storm events, an ICS wire down operation is initiated to support Operators and deploy additional wire down resources, such as wire guards, wire evaluators, and damage assessors.

Company witness Snider goes on to say that Bright Yellow “Caution Do Not Enter” tape is used to secure wire downs. He further states that the caution tape is used to barricade the area to keep pedestrians at least 25 feet from the wire and any objects in contact with the downed wire. Below is an example of the wire down tape the Company uses.



Q. Do Company personnel stand by every single wire down after a storm?

A. No, Staff recently learned from the Company that they do not have enough resources to allow personnel to stand by every wire down after a storm occurs.

Q. Is Staff concerned with the wire down tape the Company chooses to use?

A. Yes, Staff is very concerned with the wire down tape the Company uses. The wire down tape the Company uses does not give the public any indication of what may be behind the taped-off area or why they are not supposed to be entering the area taped off. Many construction companies, municipalities, and public safety use similar caution tape to secure an area. Staff is concerned that members of the public will see “Caution Do Not

DIRECT TESTIMONY OF JESSICA DUELL
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Enter” on tape placed by Consumers Energy and think that it may not be too big of a risk to enter, not realizing there is a dangerous live wire or wires behind the tape.

Q. Does Staff have any recommendation to the Company regarding their wire down caution tape?

A. Yes, Staff recommends the Company change their caution tape to one that states “Caution Live Wire” or “Danger Live Wire Keep Away”. DTE Electric uses caution tape for a downed wire that states “Danger-Live Wire-Keep Away” and it has the Company’s name underneath. Below is a picture of DTE Electric’s caution tape for wire downs⁷. If the Company switches their caution tape to one similar to DTE’s then the public will know to stay away because it’s a downed wire. The public’s safety should be the Company’s upmost priority, so changing the caution tape to one that states “caution live wire stay away” or something similar can aid in the Company’s efforts to keep their customers safe.



Summary

Q. Please summarize your recommendations.

A. 1. Staff recommends approval of \$186,684,000 for the projected test year in line clearing.
 2. Staff recommends approval of a tree trimming regulatory asset but with the return at Staff’s short term debt rate.

⁷ U-21860 DTE Discovery Response

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PART II

- 1 3. Staff recommends the Company clear 100% of overhang in the first zone.
- 2 4. Staff supports the Company's proposal of removing 10%, or roughly 5,500 miles, of
- 3 three phase overhead primary tree overhang in everything outside of the first zone.
- 4 5. Staff recommends the Company spend all line clearing O&M they request and receive
- 5 approval for and clear all miles that they propose and are approved to clear each year.
- 6 6. Staff recommends the Company be more detailed and descriptive when responding to
- 7 Staff with their discovery answers.
- 8 7. Staff recommends approval of \$165,200,000 for the projected test year O&M expense
- 9 in service restoration.
- 10 8. Staff recommends the Resiliency Fund not be approved.
- 11 9. Staff recommends a disallowance of \$2,435,500 for the Control/Dispatch Center
- 12 consolidation project in the bridge period.
- 13 10. Staff recommends a disallowance of \$7,748,500 for the Control/Dispatch Center
- 14 consolidation project in the projected test year.
- 15 11. Staff recommends a disallowance of \$31,082 for the Artificial Intelligence Project in
- 16 the bridge period.
- 17 12. Staff recommends a disallowance of \$56,805 for the Artificial Intelligence Project in
- 18 the projected test year.
- 19 13. Staff recommends the Company change their caution tape for wire downs.

20
21 Q. Does this conclude your testimony?

22 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
generation and distribution of electricity
and for other relief.**

Case No. U-21870

REBUTTAL TESTIMONY OF
JESSICA DUELL
MICHIGAN PUBLIC SERVICE COMMISSION

October 21, 2025

**REBUTTAL TESTIMONY OF JESSICA DUELL
CASE NUMBER U-21870**

1 Q. Are you the same Jessica Duell who filed direct testimony on behalf of Michigan
2 Public Service Commission (MPSC or Commission) Staff (Staff) in the instant
3 case?

4 A. Yes.

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

6 A. The purpose of my rebuttal testimony is to: 1) provide a general response to
7 several recommendations from intervenors regarding line clearing; and 2) respond
8 to Association of Businesses Advocating Tariff Equity (ABATE) witness Jessica
9 A. York's recommendation to disallow projected test year HVD Line Clearing
10 Operations and Maintenance (O&M) expense of 10% or \$1.184 million.

11 Q. Are you sponsoring any exhibits?

12 A. Yes, I am sponsoring exhibits with my rebuttal testimony.

<u>Exhibit No.</u>	<u>Description</u>
14 Exhibit S-20	Consumers Energy's response to Staff discovery U21870-ST- 15 CE-0115

16
17 **Line Clearing**

18 Q. Can you provide a summary of the Line Clearing recommendations from Citizens
19 Utility Board (CUB) witness Richard J. Bunch?

20 A. Yes. CUB witness Bunch recommends on page 40, lines 12-18 of direct
21 testimony:

22 The Company proposes spending \$186,684,000 on forestry in the test
23 year. (Table 4) Adjusting its historical test year spending for PAI
24 [Productivity-adjusted Inflation] yields a baseline figure of \$113,977,000.
25 Any proposed amount in excess of that figure represents increased activity
26 over adjusted baseline, or surge. That amount is \$72,707,000, which is the

**REBUTTAL TESTIMONY OF JESSICA DUELL
CASE NUMBER U-21870**

figure witness Jester proposes for regulatory asset treatment and potential securitization.

Q. Can you provide a summary of the Line Clearing recommendations from Attorney General (AG) witness Sebastian Coppola?

A. Yes. AG witness Coppola recommends on page 175, lines 1-18 of direct testimony:

I recommend that the Commission approved the 2024 line clearing expense amount of \$110,225,000 as the baseline amount and direct the Company to defer all expenses above that amount beginning in 2026 to the regulatory asset. For the projected test year, the Company forecasted \$186,684,000 in O&M expense for line clearing (Forestry), as shown in Exhibit A-170 and Exhibit A-13, Schedule C-5.1. Based on this amount and the baseline of \$110,225,000, the difference of \$76,459,000 should be removed from O&M expense in this rate case and included the regulatory asset account. Later in my testimony, I will discuss the appropriate return to be applied to the regulatory asset balance. Therefore, I recommend that the Commission approve both the \$110,225,000 baseline and the transfer of \$76,459,000 from O&M expense to the regulatory asset account for the projected test year.

Q. What is Staff's recommendation regarding these proposals to shift Line Clearing O&M expenses into a regulatory asset?

A. Staff recommends the Commission reject these proposals to approve a baseline of \$110,225,000 or \$113,977,000 in Line Clearing O&M and then transfer \$76,459,000 or \$72,707,000 into a regulatory asset. Staff's position is the Commission should approve the full proposed spend of \$186,683,974 in Line Clearing O&M being requested by the Company, with \$164,445,867 being recovered as base O&M expense and \$22,238,107 being recovered as part of a regulatory asset, as shown in Figure 23 in Consumers Energy Company (Company or Consumers) witness Sara Stewart's direct testimony. Approving the Company's proposed base O&M expense for the test year will set a baseline for

**REBUTTAL TESTIMONY OF JESSICA DUELL
CASE NUMBER U-21870**

1 future annual expenses that should ultimately result in less expense going into the
2 regulatory asset over the next five years. This would mean lower interest expense
3 to ratepayers in the long run compared to CUB witness Bunch's and AG witness
4 Coppola's proposals.

5 **Disallowing HVD Line Clearing O&M Expenditures**
6

7 Q. What is ABATE witness York's recommendation with regard to HVD Line
8 Clearing O&M?

9 A. As stated on page 16, lines 1-6 of ABATE witness York's direct testimony:

10 Based on the Company's track record of maintaining consistency in 1)
11 underspending planned amounts, 2) the number of HVD line miles
12 cleared, and 3) the number of crews used to accomplish that goal, I
13 recommend reducing the Company's projected test year HVD Line
14 Clearing O&M by 10%, or \$1.184 million.
15

16 Q. Does Staff agree with this recommendation?

17 A. No. Staff does not agree with this recommendation because Consumers explained
18 to Staff that, if the Company underspends in HVD line clearing in any year, those
19 funds will be reallocated to the LVD line clearing program. (See Staff Exhibit S-
20 20.). Staff is not advocating for underspending on the HVD system, but if it
21 occurs there should be a commensurate increase in LVD line clearing spending.
22 Staff recommends the Commission approve the full spend in HVD Line Clearing
23 in the amount of \$11,840,000 for the projected test year.

24 Q. Does this conclude your rebuttal testimony?

25 A. Yes.

1 MR. SONNEVELDT: Next, Your Honor, Staff moves
2 to bind in the direct testimony of Ally Durfee. Her
3 direct testimony consists of a cover sheet and 24 pages of
4 questions and answers. In that testimony, she sponsors
5 exhibits S-16.1, S-16.2, and S-16.3

6 JUDGE THOITS: And that was direct testimony for
7 this witness.

8 MR SONNEVELDT: Correct, Your Honor.

9 JUDGE THOITS: Are there any objections to the
10 admission of this testimony or these exhibits?

11 Hearing none. The direct testimony of Ally
12 Durfee is bound into the record, and Exhibits 16.1 through
13 16.3 are admitted.

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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	)	
generation and distribution of electricity	)	Case No. U-21870
and for other relief.	)	
	)	
	)	

QUALIFICATIONS AND DIRECT TESTIMONY OF
ALLY DURFEE
MICHIGAN PUBLIC SERVICE COMMISSION

September 30, 2025

QUALIFICATIONS OF ALLY DURFEE
CASE NUMBER U-21870
PART I

1 Q. Please state your full name and business address for the record.

2 A. My name is Ally Durfee, and my business address is 7109 West Saginaw
3 Highway, Lansing, Michigan 48917.

4 Q. By whom are you employed and in what capacity?

5 A. I am employed by the Michigan Public Service Commission (MPSC or
6 Commission) as a Public Utilities Engineer in the Electric Operations Section of
7 the Energy Operations Division.

8 Q. Please describe your educational background.

9 A. I earned a Bachelor of Science degree in Civil Engineering from Utah State
10 University in 2011.

11 Q. What is your professional background?

12 A. In 2013, I began working at Rocky Mountain West Telecom (RMWT), a
13 telecommunications engineering firm in Utah, as an Engineering Assistant. I was
14 later promoted to department manager. While working at RMWT, I gained a lot
15 of experience working with many electric utilities to gain joint use rights on poles.
16 I completed many projects involving upwards of 500 poles and became very
17 familiar with the NCEES standards for pole attachments. I completed the CET
18 Design Methods and Procedures training course in 2021. I started with the MPSC
19 as a Public Utilities Engineer in the Electric Operations section in April of 2022.
20 My current responsibilities include reviewing reasonableness and prudence of
21 electric rate cases and testifying on my findings.

22 Q. Have you received any work-related training since starting your employment with
23 the MPSC?

QUALIFICATIONS OF ALLY DURFEE

CASE NUMBER U-21870

PART I

A. Yes. In June of 2022, I completed the Michigan Infrastructure Council Asset Management Champion Course through the Michigan Infrastructure Council. I also completed Stray Voltage Training that same month. I completed the IPU's Annual Regulatory Studies Program Fundamentals Course, the Incident Investigation, Root Cause Analysis Training and MORT Certification, and the Basics Practical Regulatory Training for the Electric Industry. I have also completed several EUCI training courses including Distribution Reliability Fundamentals, Electric Utility Pricing: Trends in Cost Recovery, Electric Distribution Safety, and Electric Distribution Planning Fundamentals. I attended the Distribution System Planning and Resilience Training by NASEO, NARUC & LBNL.

Q. Have you previously testified before the Commission?

A. Yes. I have filed testimony in the following cases:

<u>Case No.</u>	<u>Company</u>	<u>Type of case</u>	<u>Assisted with</u>
U-21224	Consumers Energy	Electric Rate	Service Restoration, Line Clearing, and CVR
U-21286	Upper Peninsula Power Company	Electric Rate	Substation Projects
U-21461	Indiana Michigan Power Company	Electric Rate	Distribution Capital Expenditures
U-21534	DTE Electric	Electric Rate	Strategic Capital
U-21585	Consumers Energy	Electric Rate	Wildfire risk mitigation, electric distribution O&M, and undergrounding pilot

QUALIFICATIONS OF ALLY DURFEE

CASE NUMBER U-21870

PART I

1		U-21860	DTE Electric	Electric Rate	Distribution Base
2					Capital Programs
3	Q.	Have you provided technical assistance in any other cases?			
4	A.	Yes, in the following case:			
5		<u>Case No.</u>	<u>Company</u>	<u>Type of Case</u>	<u>Assisted with:</u>
6		U-21297	DTE Electric	Electric Rate	Distribution capital

DIRECT TESTIMONY OF ALLY DURFEE
CASE NUMBER U-21870
PART II

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

2 A. The purpose of my testimony is to present the Michigan Public Service
3 Commission Staff's (Staff) recommendations regarding Consumers Energy
4 Company's (Consumers or the Company) HVD (High-Voltage Distribution)
5 System Capital Expenditures and Electric Distribution O&M Expenses.

6 Q. Are you sponsoring any exhibits?

7 A. Yes. I am sponsoring the following exhibits:

8 Exhibit Description

9 S-16.1 Historical Electric Capital Expenses.

10 S-16.2 Historical O&M Expenses.

11 S-16.3 Exhibit AG-1.34 from U-21585

12 **HVD Capital Investments**

13 Q. Briefly describe the HVD System.

14 A. The HVD System is considered the backbone of the Company's distribution
15 system. It consists of HVD Lines and substations that distribute electricity to its
16 LVD (Low-Voltage Distribution) substations along with a system of protective
17 relays. There are approximately 4600 overhead miles, 23 underground miles, and
18 a total of 1138 substations on the HVD system.

19 Q. Briefly describe the Company's HVD Capital Investments.

20 A. The Company classifies its capital investments under two classifications, planned
21 and unplanned. The Planned classification includes the Reliability, Capacity, and
22 Electric Other programs. The Unplanned classification includes the New
23 Business, Demand Failures, and Asset Relocation programs.

DIRECT TESTIMONY OF ALLY DURFEE
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PART II

1 Q. Did Staff review the Company's proposed HVD Capital Investments?

2 A. Yes.

3 Q. Does Staff have any concerns with the Company's proposed HVD capital
4 investments?

5 A. Yes; after a thorough review of the HVD capital investments staff is concerned
6 with three sub-programs within the Reliability program, one sub-program within
7 the Electric Other program, and two sub-programs within the Demand Failures
8 program.

9 Q. Please list the Reliability sub-programs Staff has concerns with.

10 A. Substations Reliability HVD
11 Transformer Bank Replacement and Substation Rebuilds
12 Metro Rehabilitation

13 Q. What are the Company's projected expenditures for the Substation Reliability
14 HVD sub-program?

15 A. The Company's projected expenditures as presented in Exhibit A-113 (MPK-3),
16 page 1, are as follows:

17 2025 - \$33,222,000

18 4 months ending 4/30/2026 - \$14,100,000

19 12 months ending 4/30/2027 - \$39,680,000

20 The Company also spent \$7,321,000 in the first 6 months of 2025. See Exhibit S-
21 16.1.

22 Q. What is Staff's assessment of the Substation Reliability HVD sub-program?

DIRECT TESTIMONY OF ALLY DURFEE
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PART II

1 A. Staff agrees that the Substation Reliability HVD sub-program ensures the long-
 2 term safe and reliable operation of HVD substitutions, along with keeping up the
 3 asset health of HVD substations. However, given that the Company has only
 4 spent a fraction of what is needed to meet the projected spend in 2025 Staff is
 5 recommending adjusting the projected expenditures.

6 Q. How were the adjusted projected expenditures calculated?

7 A. Assuming linear monthly spend, the actual expenditures for the first six months of
 8 2025 were projected to get to a total spend for 2025 of \$14,642,000
 9 (\$7,321,000*2). Based on this projection, Staff recommends a disallowance of
 10 \$18,580,000 (\$33,222,000-\$14,642,000) for 2025.

11 Applying the Company's 2.40% inflation factor for 2026 (see Company Witness
 12 Daly Direct Testimony, page 14), Staff projects an expenditure of \$4,993,000
 13 (\$14,642,000*1.024*0.333) for the 4 months ending 4/30/2026 and recommends
 14 a disallowance of \$9,107,000 (\$14,100,000-\$4,993,000).

15 Applying a 2.40% inflation factor for 2027 Staff projects an expenditure of
 16 \$15,113,000 ((\$14,642,000*1.024*0.667)+(\$14,642,000*1.024*1.024*0.333)) for
 17 the 12 months ending 4/30/2027 and recommends a disallowance of \$24,567,000
 18 (\$39,680,000-\$15,113,000).

19 Q. What are the Company's projected expenditures for the Transformer Bank
 20 Replacement and Substation Rebuilds sub-program?

21 A. The Company's projected expenditures as presented in Exhibit A-113 (MPK-3),
 22 page 1, are as follows:

23 2025 - \$ 35,332,000

DIRECT TESTIMONY OF ALLY DURFEE
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PART II

1 4 months ending 4/30/2026 - \$11,333,000

2 12 months ending 4/30/2027 - \$37,667,000

3 The Company also spent \$7,468,000 in the first 6 months of 2025. See Exhibit S-
4 16.1.

5 Q. What is Staff's assessment of the Transformer Bank Replacement and Substation
6 Rebuilds sub-program?

7 A. Staff agrees that Transformer Bank Replacement and Substation Rebuilds sub-
8 program is necessary to prevent long-term outages and ensure the substations are
9 ready to serve customers. However, given that the Company has only spent a
10 fraction of what is needed to meet the projected spend in 2025, Staff is
11 recommending adjusting the projected expenditures.

12 Q. How were the adjusted projected expenditures calculated?

13 A. Assuming linear monthly spend, the actual expenditures for the first six months of
14 2025 were projected to get to a total spend for 2025 of \$14,936,000
15 (\$7,468,000*2). Based on this projection, Staff recommends a disallowance of
16 \$20,396,000 (\$35,332,000-\$14,936,000) for 2025.

17 Applying a 2.40% inflation factor for 2026, Staff projects an expenditure of
18 \$5,093,000 (\$14,936,000*1.024*0.333) for the 4 months ending 4/30/2026 and
19 recommends a disallowance of \$6,240,000 (\$11,333,000-\$5,093,000).

20 Applying a 2.40% inflation factor for 2027, Staff projects an expenditure of
21 \$15,417,000 ((\$14,936,000*1.024*0.667)+(\$14,936,000*1.024*1.024*0.333)) for
22 the 12 months ending 4/30/2027 and recommends a disallowance of
23 \$22,250,000(\$37,667,000-\$15,417,000).

DIRECT TESTIMONY OF ALLY DURFEE
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PART II

1 Q. What are the Company's projected expenditures for the Metro Rehabilitation sub-
2 program?

3 A. The Company's projected expenditures as presented in Exhibit A-113 (MPK-3),
4 page 1, are as follows:

5 2025 - \$5,990,000

6 4 months ending 4/30/2026 - \$1,997,000

7 12 months ending 4/30/2027 - \$5,993,000

8 The Company also spent \$1,430,000 in the first 6 months of 2025. See Exhibit S-
9 16.1.

10 Q. What is Staff's assessment of the Metro Rehabilitation sub-program?

11 A. Staff agrees that investments in the Metro Rehabilitation sub-program will
12 provide a reliability benefit to customers by maintaining redundancy, help provide
13 a safe work environment for contractors, and support public safety. However,
14 given that the Company has only spent a fraction of what is needed to meet the
15 projected spend in 2025, Staff is recommending adjusting the projected
16 expenditures.

17 Q. How were the adjusted projected expenditures calculated?

18 A. Assuming linear monthly spend, the actual expenditures for the first six months of
19 2025 were projected to get to a total spend for 2025 of \$2,860,000 (\$1,430,000
20 *2). Based on this projection, Staff recommends a disallowance of \$3,130,000
21 (\$5,990,000-\$2,860,000) for 2025.

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1 Applying a 2.40% inflation factor for 2026, Staff projects an expenditure of
 2 \$975,000 ($\$2,860,000 * 1.024 * 0.333$) for the 4 months ending 4/30/2026 and
 3 recommends a disallowance of \$1,022,000 ($\$1,997,000 - \$975,000$).

4 Applying a 2.40% inflation factor for 2027, Staff projects an expenditure of
 5 \$2,952,000 ($(\$2,860,000 * 1.024 * 0.667) + (\$2,860,000 * 1.024 * 1.024 * 0.333)$) for
 6 the 12 months ending 4/30/2027 and recommends a disallowance of \$3,041,000
 7 ($\$5,993,000 - \$2,952,000$).

8 Q. What Electric Other sub-program does Staff have concerns with?

9 A. The System Control Projects sub-program.

10 Q. What are the Company's projected expenditures for the System Control Projects
 11 sub-program?

12 A. The Company's projected expenditures as presented in Exhibit A-113 (MPK-3),
 13 page 1, are as follows:

14 2025 - \$279,000

15 4 months ending 4/30/2026 - \$93,000

16 12 months ending 4/30/2027 - \$219,000

17 The Company also spent \$70,000 in the first 6 months of 2025. See Exhibit S-
 18 16.1.

19 Q. What is Staff's assessment of the System Control Projects sub-program?

20 A. Staff agrees that the investments in the System Control Projects will benefit
 21 customers and better enable employees to provide safe and reliable electricity.
 22 However, given that the Company has only spent a fraction of what is needed to

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PART II

1 meet the projected spend in 2025, Staff is recommending adjusting the projected
2 expenditures.

3 Q. How were the adjusted projected expenditures calculated?

4 A. Assuming linear monthly spend, the actual expenditures for the first six months of
5 2025 were projected to get to a total spend for 2025 of \$140,000 ($\$70,000 \times 2$).

6 Based on this projection, Staff recommends a disallowance of \$139,000
7 ($\$279,000 - \$140,000$) for 2025.

8 Applying a 2.40% inflation factor for 2026, Staff projects an expenditure of
9 \$48,000 ($\$139,000 \times 1.024 \times 0.333$) for the 4 months ending 4/30/2026 and
10 recommends a disallowance of \$45,000 ($\$93,000 - \$48,000$).

11 Applying a 2.40% inflation factor for 2027, Staff projects an expenditure of
12 \$145,000 ($(\$139,000 \times 1.024 \times 0.667) + (\$139,000 \times 1.024 \times 1.024 \times 0.333)$) for the 12
13 months ending 4/30/2027 and recommends a disallowance of \$74,000 ($\$219,000 -$
14 $\$145,000$).

15 Q. Please list the Demand Failures sub-programs Staff has concerns with.

16 A. Substations Failures-LVD

17 Metro Failures

18 Q. What are the Company's projected expenditures for the Substations Failures-LVD
19 sub-program?

20 A. The Company's projected expenditures as presented in Exhibit A-113 (MPK-3),
21 page 1, are as follows:

22 2025 - \$8,942,000

23 4 months ending 4/30/2026 - \$2,981,000

DIRECT TESTIMONY OF ALLY DURFEE
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12 months ending 4/30/2027 - \$8,961,000

Q. What is Staff's assessment of the Substations Failures-LVD sub-program?

A. Staff agrees that the work in the Substation Failures-LVD sub-program is essential to restoring interruptions or restoring the safe and reliable operations of the substations, but Staff does not agree with the unit prices used for transformers. The Company states that the unit price for transformers is based on historical information and is inclusive of projected increased costs. However, the 5-year historical information presented in Exhibit A-130 (MPK-29), page 2, line 30, shows the cost of transformers per unit has not consistently increased. The unit price decreased from 2021 to 2022 and from 2023 to 2024. Therefore, Staff is recommending adjusting the projected expenditures.

Q. How were the adjusted projected expenditures calculated?

A. Using the Company's projected number of units and an average unit cost of \$700,000 (calculated based on the historical data listed in Exhibit A-130 (MPK-29), page 2, line 30), Staff projected an expenditure of \$2,800,000 ($4 * \$700,000$) for both the bridge period and the 12 months ending 4/30/2027. Staff recommends a disallowance of \$580,000 ($\$3,380,000 - \$2,800,000$) for the 12 months ending 4/30/2027, \$435,000 ($580,000 * 0.75$) for 2025 and \$145,000 ($\$580,000 * 0.25$) for 4 months ending 4/30/2026.

Q. What are the Company's projected expenditures for the Metro Failures sub-program?

A. The Company's projected expenditures as presented in Exhibit A-113 (MPK-3), page 1, are as follows:

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1 2025 - \$547,000

2 4 months ending 4/30/2026 - \$117,000

3 12 months ending 4/30/2027 - \$350,000

4 The Company also spent \$9,000 in the first 6 months of 2025. See Exhibit S-16.1.

5 Q. What is Staff's assessment of the Metro Failures sub-program?

6 A. Staff agrees that investment in this category is necessary to restore electric service
7 to customers on the Metro system. However, given that the Company has only
8 spent a fraction of what is needed to meet the projected spend in 2025, Staff is
9 recommending adjusting the projected expenditures.

10 Q. How were the adjusted projected expenditures calculated?

11 A. Assuming linear monthly spend, the actual expenditures for the first six months of
12 2025 were projected to get to a total spend for 2025 of \$18,000 ($\$9,000 \times 2$). Based
13 on this projection, Staff recommends a disallowance of \$529,000 ($\$547,000 -$
14 $\$18,000$) for 2025.

15 Applying a 2.40% inflation factor for 2026, Staff projects an expenditure of
16 \$6,000 ($\$18,000 \times 1.024 \times 0.333$) for the 4 months ending 4/30/2026 and
17 recommends a disallowance of 111,000 ($\$117,000 - \$6,000$).

18 Applying a 2.40% inflation factor for 2027, Staff projects an expenditure of
19 \$19,000 ($(\$18,000 \times 1.024 \times 0.667) + (\$18,000 \times 1.024 \times 1.024 \times 0.333)$) for the 12
20 months ending 4/30/2027 and recommends a disallowance of \$331,000
21 ($\$350,000 - \$19,000$).

22 **Electric Distribution O&M**

23 Q. Briefly describe the Electric Distribution O&M expenses.

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1 A. The Electric Distribution O&M expenses include funding for the Company's
2 distribution Operation and Engineering functions along with certain internal
3 organizations such as training and equipment repair.

4 The Electric Distribution O&M programs are classified into Electric Operations,
5 and Electric Engineering and Support.

6 The programs included in Electric Operations are:

7 O&M Associated with Construction
8 Non-Forestry Reliability
9 Operations, Maintenance, and Metering
10 Service Restoration
11 Field Operations
12 Compliance and Controls
13 Planning and Scheduling
14 Work Management and Customer Delivery
15 Operations Management

16 The programs included in Electric Engineering and Support are:

17 Engineering Support
18 Electric Distribution Management
19 Electric Distribution - LVD
20 Electric Distribution - HVD
21 Electric Distribution Strategy
22 Wildfire Risk Mitigation O&M

23 Q. Did Staff review the Electric Distribution O&M expenses?

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PART II

1 A. Yes.

2 Q. Does Staff have any concerns with the company's proposed Electric Distribution
3 O&M expenses?

4 A. Yes, after a thorough review of the expenses, Staff is concerned with three sub-
5 programs within the Non-Forestry Reliability program, three sub-programs within
6 the Operations, Maintenance, and Metering program, and two sub-programs
7 within the Field Operations program.

8 Q. Please list the Non-Forestry Reliability sub-programs Staff have concerns with.

9 A. Lines Reliability LVD

10 Lines Reliability HVD

11 Substations Reliability LVD

12 Q. What are the Company's projected expenses for the Lines Reliability LVD sub-
13 program?

14 A. The Company's projected expenses as presented in Exhibit A-124 (MPK-14) are
15 as follows:

16 2025 - \$8,000,000

17 12 months ending 4/30/2027 - \$8,000,000

18 The Company also spent \$377,000 in the first 6 months of 2025. See Exhibit S-
19 16.2.

20 Q. What is Staff's assessment of the Lines Reliability LVD sub-program?

21 A. Staff agrees that the Lines Reliability LVD sub-program reduces caused outages
22 by proactively inspecting the equipment to find potential failures before they
23 occur. However, given that the Company has only spent a fraction of what is

DIRECT TESTIMONY OF ALLY DURFEE
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PART II

1 needed to meet the projected spend in 2025, Staff is recommending adjusting the
 2 projected expenses.

3 Q. How were the adjusted projected expenses calculated?

4 A. Assuming linear monthly spend, the actual expenses for the first six months of
 5 2025 were projected to get to a total spend for 2025 of \$754,000 ($\$377,000 \times 2$).

6 Applying a 2.40% inflation factor for 2026 and 2027, Staff projects an
 7 expenditure of \$778,000

8 $((\$754,000 \times 1.024 \times 0.667) + (\$754,000 \times 1.024 \times 1.024 \times 0.333))$ for the 12 months
 9 ending 4/30/2027 and recommends a disallowance of \$7,222,000 (\$8,000,000-
 10 \$778,000).

11 Q. What are the Company's projected expenses for the Lines Reliability HVD sub-
 12 program?

13 A. The Company's projected expenses as presented in Exhibit A-124 (MPK-14) are
 14 as follows:

15 2025 - \$784,000

16 12 months ending 4/30/2027 - \$891,000

17 The Company also spent \$34,000 in the first 6 months of 2025. See Exhibit S-
 18 16.2.

19 Q. What is Staff's assessment of the Lines Reliability HVD sub-program?

20 A. Staff agrees that the Lines Reliability HVD sub-program reduces outages by
 21 proactively inspecting the equipment to find potential failures before they occur.
 22 However, given that the Company has only spent a fraction of what is needed to

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PART II

1 meet the projected spend in 2025, Staff is recommending adjusting the projected
2 expenses.

3 Q. How were the adjusted projected expenses calculated?

4 A. Assuming linear monthly spend, the actual expenses for the first six months of
5 2025 were projected to get to a total spend for 2025 of \$68,000 ($\$34,000 \times 2$).
6 Applying a 2.40% inflation factor for 2026 and 2027, Staff projects an expense of
7 \$70,000 ($(\$68,000 \times 1.024 \times 0.667) + (\$68,000 \times 1.024 \times 1.024 \times 0.333)$) for the 12
8 months ending 4/30/2027 and recommends a disallowance of \$821,000
9 ($\$891,000 - \$70,000$).

10 Q. What are the Company's projected expenses for the Substations Reliability LVD
11 sub-program?

12 A. The Company's projected expenses as presented in Exhibit A-124 (MPK-14) are
13 as follows:

14 2025 - \$784,000

15 12 months ending 4/30/2027 - \$891,000

16 The Company also spent \$1,906,000 in the first 6 months of 2025. See Exhibit S-
17 16.2.

18 Q. What is Staff's assessment of the Substations Reliability LVD sub-program?

19 A. Staff agrees that the Substations Reliability LVD sub-program reduces outages by
20 proactively inspecting the equipment to find potential failures before they occur.
21 However, given that the Company has only spent a fraction of what is needed to
22 meet the projected spend in 2025, Staff is recommending adjusting the projected
23 expenses.

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1 Q. How were the adjusted projected expenses calculated?

2 A. Assuming linear monthly spend, the actual expenses for the first six months of
 3 2025 were projected to get to a total spend for 2025 of \$3,821,000
 4 (\$1,906,000*2). Applying a 2.40% inflation factor for 2026 and 2027, Staff
 5 projects an expense of \$3,935,000 $((\$3,821,000 * 1.024 * 0.667) + (\$$
 6 $3,821,000 * 1.024 * 1.024 * 0.333))$ for the 12 months ending 4/30/2027 and
 7 recommends a disallowance of \$1,540,000 $(\$5,475,000 - \$3,935,000)$.

8 Q. Please list the Non-Forestry Reliability sub-programs Staff has concerns with.

9 A. Lines Demand HVD
 10 Staking
 11 Alma Equipment Repair

12 Q. What are the Company's projected expenses for the Lines Demand HVD sub-
 13 program?

14 A. The Company's projected expenses as presented in Exhibit A-124 (MPK-14) are
 15 as follows:

16 2025 - \$2,237,000

17 12 months ending 4/30/2027 - \$2,979,000

18 The Company also spent \$256,000 in the first 6 months of 2025. See Exhibit S-
 19 16.2.

20 Q. What is Staff's assessment of the Lines Demand HVD sub-program?

21 A. Staff agrees that the Lines Demand HVD sub-program reduces outages and
 22 improves system integrity and reliability with preventative maintenance through
 23 repairs and upgrades of non-capital assets, downed wires, splice and connector

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1 replacements. However, given that the Company has only spent a fraction of what
 2 is needed to meet the projected spend in 2025, Staff is recommending adjusting
 3 the projected expenses.

4 Q. How were the adjusted projected expenses calculated?

5 A. Assuming linear monthly spend, the actual expenses for the first six months of
 6 2025 were projected to get to a total spend for 2025 of \$512,000 ($\$256,000 \times 2$).
 7 Applying a 2.40% inflation factor for 2026 and 2027, Staff projects an expense of
 8 \$528,000 ($(\$512,000 \times 1.024 \times 0.667) + (\$512,000 \times 1.024 \times 1.024 \times 0.333)$) for the 12
 9 months ending 4/30/2027 and recommends a disallowance of \$2,451,000
 10 ($\$2,979,000 - \$528,000$).

11 Q. What are the Company's projected expenses for the Staking sub-program?

12 A. The Company's projected expenses as presented in Exhibit A-124 (MPK-14) are
 13 as follows:

14 2025 - \$12,260,000

15 12 months ending 4/30/2027 - \$13,948,000

16 The Company also spent \$256,000 in the first 6 months of 2025. See Exhibit S-
 17 16.2.

18 Q. What is Staff's assessment of the Staking sub-program?

19 A. Staff agrees that the work in the Staking sub-program is necessary to keep the
 20 public and employees safe, but Staff does not agree with the anticipated volume
 21 increase of 7%. The anticipated 7% was calculated using MISS DIG 811
 22 statewide annual growth. However, in the 3/21/2025 U-21585 Commission Order
 23 the Commission agreed with the argument that the Company's growth rate is

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PART II

1 consistently lower than the statewide average. Therefore, Staff is recommending
 2 adjusting the projected expenses.

3 Q. How were the adjusted projected expenses calculated?

4 A. Starting with the historic staking requests received by the Company (see Exhibit
 5 S-16.3), an annual increase of 2.28% was used to project 453,113
 6 (433,137*1.0228*1.0228) requests for 2026 and 463,444 (453,113*1.0228)
 7 requests for 2027. Using the Company's proposed unit costs for 2026 and 2027,
 8 an expense of \$12,431,000 (453,113*\$26.93*.667)+(463,444*\$27.81*0.333) for
 9 the 12 months ending 4/30/2027 results, and Staff therefore recommends a
 10 disallowance of \$1,517,000 (\$13,948,000-\$12,431,000).

11 Q. What are the Company's projected expenses for the Alma Equipment Repair sub-
 12 program?

13 A. The Company's projected expenses as presented in Exhibit A-124 (MPK-14) are
 14 as follows:

15 2025 - \$563,000

16 12 months ending 4/30/2027 - \$571,000

17 The Company also spent \$179,000 in the first 6 months of 2025. See Exhibit S-
 18 16.2.

19 Q. What is Staff's assessment of the Alma Equipment Repair sub-program?

20 A. Staff agrees that the Alma Equipment Repair sub-program reduces outages and
 21 improves system integrity and reliability with preventative maintenance through
 22 repairs and upgrades of non-capital assets, downed wires, splice and connector
 23 replacements. However, given that the Company has only spent a fraction of what

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PART II

1 is needed to meet the projected spend in 2025, Staff is recommending adjusting
 2 the projected expenses.

3 Q. How were the adjusted projected expenses calculated?

4 A. Assuming linear monthly spend, the actual expenses for the first six months of
 5 2025 were projected to get to a total spend for 2025 of \$358,000 (\$179,000*2).
 6 Applying a 2.40% inflation factor for 2026 and 2027, Staff projects an expense of
 7 \$370,000 $((\$358,000 * 1.024 * 0.667) + (\$358,000 * 1.024 * 1.024 * 0.333))$ for the 12
 8 months ending 4/30/2027 and recommends a disallowance of \$201,000
 9 (\$571,000-\$370,000).

10 Q. Please list the Non-Forestry Reliability sub-programs Staff have concerns with.

11 A. Tools
 12 Undergrounding Workforce

13 Q. What are the Company's projected expenses for the Tools sub-program?

14 A. The Company's projected expenses as presented in Exhibit A-124 (MPK-14) are
 15 as follows:

16 2025 - \$1,497,000
 17 12 months ending 4/30/2027 - \$1,982,000

18 The Company also spent \$448,000 in the first 6 months of 2025. See Exhibit S-
 19 16.2.

20 Q. What is Staff's assessment of the Tools sub-program?

21 A. Staff agrees that the Tools sub-program is necessary to acquire the tools needed to
 22 complete field work to improve reliability and restore service. However, given

DIRECT TESTIMONY OF ALLY DURFEE
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PART II

1 that the Company has only spent a fraction of what is needed to meet the
2 projected spend in 2025, Staff is recommending adjusting the projected expenses.

3 Q. How were the adjusted projected expenses calculated?

4 A. Assuming linear monthly spend, the actual expenses for the first six months of
5 2025 were projected to get to a total spend for 2025 of \$896,000 ($\$448,000 \times 2$).
6 Applying a 2.40% inflation factor for 2026 and 2027, Staff projects an expense of
7 \$925,000 ($(\$896,000 \times 1.024 \times 0.667) + (\$896,000 \times 1.024 \times 1.024 \times 0.333)$) for the 12
8 months ending 4/30/2027 and recommends a disallowance of \$1,057,000
9 (\$1,982,000-\$925,000).

10 Q. What are the Company's projected expenses for the Underground Workforce sub-
11 program?

12 A. The Company's projected expenses as presented in Exhibit A-124 (MPK-14) are
13 as follows:

14 2025 - \$1,113,000

15 12 months ending 4/30/2027 - \$2,236,000

16 The Company also spent \$292,000 in the first 6 months of 2025. See Exhibit S-
17 16.2.

18 Q. What is Staff's assessment of the Underground Workforce sub-program?

19 A. Staff agrees that the Underground Workforce sub-program is necessary. However,
20 given that the Company has only spent a fraction of what is needed to meet the
21 projected spend in 2025, Staff is recommending adjusting the projected expenses.

22 Q. How were the adjusted projected expenses calculated?

DIRECT TESTIMONY OF ALLY DURFEE
CASE NUMBER U-21870
PART II

1 A. Assuming linear monthly spend, the actual expenses for the first six months of
2 2025 were projected to get to a total spend for 2025 of \$584,000 (\$292,000*2).
3 Applying a 2.40% inflation factor for 2026 and 2027, Staff projects an expense of
4 \$603,000 $((\$584,000 * 1.024 * 0.667) + (\$584,000 * 1.024 * 1.024 * 0.333))$ for the 12
5 months ending 4/30/2027 and recommends a disallowance of \$1,633,000
6 (\$2,236,000-\$603,000).

7 Q. Please summarize your recommendations.

8 A. Staff's recommendations are as follows:

9 HVD Capital Investments

10 Substations Reliability HVD

11 Disallowance of \$18,580,000 for 2025

12 Disallowance of \$9,107,000 for 4 months ending 4/30/2026

13 Disallowance of \$24,567,000 for 12 months ending 4/30/2027

14 Transformer Bank Replacement and Substation Rebuilds

15 Disallowance of \$20,396,000 for 2025

16 Disallowance of \$6,240,000 for 4 months ending 4/30/2026

17 Disallowance of \$22,250,000 for 12 months ending 4/30/2027

18 Metro Rehabilitation

19 Disallowance of \$3,130,000 for 2025

20 Disallowance of 1,022,000 for 4 months ending 4/30/2026

21 Disallowance of \$3,041,000 for 12 months ending 4/30/2027

22 System Control Projects

23 Disallowance of \$139,000 for 2025

DIRECT TESTIMONY OF ALLY DURFEE
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1 Disallowance of \$45,000 for 4 months ending 4/30/2026

2 Disallowance of \$74,000 for 12 months ending 4/30/2027

3 Substations Failures- LVD

4 Disallowance of \$435,000 for 2025

5 Disallowance of \$145,000 for 4 months ending 4/30/2026

6 Disallowance of \$580,000 for 12 months ending 4/30/2027

7 Metro Failures

8 Disallowance of \$529,000 for 2025

9 Disallowance of \$45,000 for 4 months ending 4/30/2026

10 Disallowance of \$331,000 for 12 months ending 4/30/2027

11 Electric Distribution O&M

12 Lines Reliability LVD

13 disallowance of \$7,222,000 for 12 months ending 4/30/2027

14 Lines Reliability HVD

15 disallowance of \$821,000 for 12 months ending 4/30/2027

16 Substations Reliability LVD

17 disallowance of \$1,540,000 for 12 months ending 4/30/2027

18 Lines Demand HVD

19 disallowance of \$2,451,000 for 12 months ending 4/30/2027

20 Staking

21 disallowance of \$1,517,000 for 12 months ending 4/30/2027

22 Alma Equipment Repair

23 disallowance of \$201,000 for 12 months ending 4/30/2027

DIRECT TESTIMONY OF ALLY DURFEE
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PART II

1	Tools
2	disallowance of \$1,057,000 for 12 months ending 4/30/2027
3	Undergrounding Workforce
4	disallowance of \$1,633,000 for 12 months ending 4/30/2027
5	
6	Q. Does this conclude your testimony?
7	A. Yes.

1 MR. SONNEVELDT: Next, Your Honor, Staff moves
2 to bind in the direct and rebuttal testimony of Nicholas
3 M. Evans. His direct testimony consists of a cover sheet
4 and 17 pages of questions and answers. The rebuttal
5 testimony consists of a cover sheet and two pages of
6 questions and answers. He sponsors no exhibits in either
7 testimony.

8 JUDGE THOITS: Are there any objections to the
9 admission of this testimony?

10 Hearing none. The direct and rebuttal testimony
11 of Nicholas Evans is bound into the record.

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)
generation and distribution of electricity)
and for other relief.)

)

Case No. U-21870

QUALIFICATIONS AND DIRECT TESTIMONY OF
NICHOLAS M. EVANS
MICHIGAN PUBLIC SERVICE COMMISSION

September 30, 2025

QUALIFICATIONS OF NICHOLAS M. EVANS
CASE NUMBER U-21870
PART I

1 Q. Please state your full name and business address for the record.

2 A. My name is Nicholas M. Evans (he/him/his), and my business address is 7109 West
3 Saginaw Highway, Lansing, Michigan 48917.

4 Q. By whom are you employed and in what capacity?

5 A. I am employed by the Michigan Public Service Commission (MPSC or Commission) as
6 Manager of the Electric Operations Section. This section is part of the Energy
7 Operations Division, which is responsible for ensuring safe, reliable, and accessible
8 energy supplies.

9 Q. Please describe your educational background.

10 A. I earned a Bachelor of Science in Electrical Engineering from Kettering University in
11 2005. In addition, I earned a Master of Public Administration degree from Western
12 Michigan University in 2012.

13 Q. What is your professional background?

14 A. In 2007, I began working at the State of Michigan Energy Office as a staff engineer,
15 where I performed energy audits on local government, school district, and state office
16 buildings and advised the building managers and other personnel on ways to conserve
17 energy and increase their buildings' energy efficiency. I also reviewed energy audits
18 from private contractors for these customers.

19 In April 2010, I began working for the MPSC in the Energy Efficiency Section as
20 a Public Utilities Engineer. In this Section, I reviewed filings made in the reconciliation
21 process of utility Energy Optimization plans. I was the case coordinator for Staff for six
22 electric cooperatives' cases and for Case Nos. U-16013 and U-16014. In addition, I

QUALIFICATIONS OF NICHOLAS M. EVANS
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PART I

1 participated in the MPSC Energy Optimization Collaborative and the MPSC Plug-in
2 Hybrid Electric Vehicle Task Force.

3 In 2010, I was placed into the Smart Grid Section where I reviewed the portions
4 of utility rate case filings that pertained to Smart Grid, Advanced Metering Infrastructure
5 (AMI) and Automated Meter Reading (AMR). I testified in several rate cases on AMI
6 issues. I also assisted in writing the Staff Report in Case No. U-17000 and was a member
7 of the MPSC Smart Grid Collaborative.

8 In 2013, I transferred to the Generation and Certificate of Need Section. My
9 primary responsibility was to review expenditures related to environmental compliance
10 and the purchase of new fossil generation in utility rate case filings. My other
11 responsibilities were to review portions of Certificate of Necessity applications and assist
12 with tracking and monitoring various environmental rules as they were proposed and
13 finalized. In 2017, I led two workgroups as part of the Integrated Resource Plan
14 Statewide Parameter Setting/Modeling stakeholder outreach process.

15 In 2017, I was promoted to a Public Utilities Engineering Specialist and began
16 working in the Electric Operations section. My primary responsibilities were to review
17 distribution system expenditures and expenses in utility rate case filings and co-lead the
18 Interconnection Standards and Worker Safety workgroup, which was tasked with
19 updating Michigan's interconnection, distributed generation, and legally enforceable
20 obligation rules. My other responsibilities were to review distribution operations five-
21 year plans, log safety incidents associated with utility equipment, assist with
22 investigations, and assist with updating the Service Quality and Reliability Standards for
23 Electric Distribution Systems rules and the Technical Standards for Electric Service rules.

QUALIFICATIONS OF NICHOLAS M. EVANS
CASE NUMBER U-21870
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1 In 2020, I was promoted to Manager of the Electric Operations Section. As
2 manager, I continue to review utility rate case filings, and I regularly assist with various
3 Commission initiatives. I also serve as a point of contact for utilities when safety
4 incidents associated with utility equipment occur. Since 2020, I have been participating
5 in the MPSC's Diversity, Equity, and Inclusion (DEI) initiative. In 2022, I began
6 assisting with the oversight of the third-party review of the electric distribution systems
7 of Consumers Energy and DTE Electric, required by the October 5, 2022 order in Case
8 No. U-21305. In 2023, I began participating in the Financial Incentives and
9 Disincentives workgroup, which was established in Case No. U-21400 and is tasked with
10 reviewing and considering issues related to the creation of financial incentives and
11 penalties involving outages and distribution performance.

12 Q. Have you received any work-related training since starting your employment with the
13 MPSC?

14 A. Yes. I have attended the following programs hosted by the Institute of Public Utilities at
15 Michigan State University: Forecasting for Regulators, Annual Regulatory Studies
16 Program, Advanced Regulatory Studies Program, Michigan Forum on Economic
17 Regulatory Policy, Introduction to Public Utility Regulation and Ratemaking, and the
18 IPU Ratemaking Course.

19 Q. Have you attended any other training programs or events since 2007?

20 A. Yes. Since 2007, I have attended training programs and events on energy auditing, smart
21 grid applications, electric generation, environmental compliance, root cause analysis,
22 asset management, diversity, equity, incident command and management, distributed

QUALIFICATIONS OF NICHOLAS M. EVANS
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energy resources, and electric distribution. Programs and events focused on electric

distribution include the following:

-Distribution Efficiency Planning and Voltage Optimization conference sponsored by EUCI, in 2012.

-Distribution Systems and Planning, hosted by NARUC, Organization of MISO States, and Lawrence Berkley National Laboratory, in 2018.

-Fundamentals of Overhead Distribution Systems, presented by EUCI, in April 2023.

-Underground Electrical Distribution Fundamentals, presented by EUCI, in April 2023.

-Electrical Distribution Safety, presented by EUCI, in May 2023.

-Electricity 101, presented by EUCI, in June 2023.

-PBR for Energy Utilities, presented by NARUC Regulatory Training Initiative, in October 2023.

Q. Have you been awarded any certificates as a result of your regulatory training?

A. Yes. In 2014, I was awarded a Tier One Certificate of Continuing Regulatory Education from the Institute of Public Utilities at Michigan State University. In July 2022, I completed the Michigan Infrastructure Council Asset Management Champion Program.

Q. Have you previously testified before the Commission?

A. Yes. I have filed testimony in the following cases:

<u>Case No</u>	<u>Company</u>	<u>Type of Case</u>	<u>Subject of Testimony</u>
U-16180	Indiana-Michigan	Electric rate (settled)	gridSMART sm project
U-16472	Detroit Edison	Electric rate	AMI, SmartCurrents
U-16794	Consumers Energy	Electric rate	AMI/Smart Grid
U-16999	MichCon	Gas rate (settled)	AMI and AMR
U-15768	Detroit Edison	Remand – Electric rate	AMI pilot program

QUALIFICATIONS OF NICHOLAS M. EVANS

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PART I

1	U-17087	Consumers Energy	Electric rate (settled)	AMI
2	U-17429	Consumers Energy	Certificate of Necessity	Thetford Plant- IRP
3			(withdrawn)	review
4				
5	U-16472	DTE Electric	Remand – Electric rate	AMI (with Rebuttal)
6	U-17735	Consumers Energy	Electric rate	Environmental capital
7				and O&M, Jackson
8				Plant
9				
10	U-17990	Consumers Energy	Electric rate	Environmental capital
11				and O&M
12				
13	U-18224	Upper Michigan	Certificate of Necessity	RICE Units –
14		Energy Resources		Environmental review
15		Corporation		
16				
17	U-18322	Consumers Energy	Electric rate	Environmental capital
18				and O&M
19				
20	U-18370	Indiana-Michigan	Electric rate	Contingency and SCR
21	U-20162	DTE Electric	Electric rate	Distribution capital
22				and O&M
23				
24	U-20561	DTE Electric	Electric rate	Distribution capital
25				and O&M
26				
27	U-20697	Consumers Energy	Electric rate	Distribution capital
28				and O&M
29				
30	U-20963	Consumers Energy	Electric rate	Distribution capital
31				and O&M (with
32				Rebuttal)
33				
34	U-20836	DTE Electric	Electric rate	Distribution system
35				programs, Vehicle
36				Fleet, outage credits
37				
38	U-21224	Consumers Energy	Electric rate	IT project, service
39				restoration, advanced lighting
40				controls
41				
42	U-21286	Upper Peninsula	Electric rate	Overhead-to-underground

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CASE NUMBER U-21870
PART I

1		Power Company		projects
2				
3	U-21297	DTE Electric	Electric rate	Distribution capital,
4				undergrounding, IT projects
5				
6	U-21389	Consumers Energy	Electric rate	Distribution deferral
7				mechanism, Investment
8				Recovery Mechanism
9				
10	U-21461	Indiana-Michigan	Electric rate	IIJA grant funding, grant
11				writing costs, outage credits
12				
13	U-21534	DTE Electric	Electric rate	Outage credits, IRM
14				
15	U-21585	Consumers Energy	Electric rate	Distribution deferral
16				mechanism, IRM
17				
18	U-21587	Consumers Energy	Complaint	Administrative rules
19				
20	U-21797	DTE Electric	Complaint	Subtransmission system
21				(Rebuttal and Supplemental
22				Rebuttal)
23				
24	U-21860	DTE Electric	Electric rate	Outage credits, IRM (with
25				Rebuttal)
26				
27	U-21845	DTE Electric	IRM reconciliation	Review process and
28				recommendations
29				
30	Q.	Have you provided technical assistance in any other cases?		
31	A.	Yes, in multiple cases:		
32	<u>Case No.</u>	<u>Company</u>	<u>Type of Case</u>	<u>Assisted with:</u>
33	U-17053	Detroit Edison	Tariff	Non-transmitting
34				meter provision
35				
36	U-15645	Consumers Energy	Remand – Electric rate	AMI pilot program.
37	U-18462	Northern States	Electric rate (settled)	Distribution system
38		Power		capital and O&M
39				
40	U-21045	Alpena Power	Electric rate (settled)	Distribution capital
41		Company		and O&M

QUALIFICATIONS OF NICHOLAS M. EVANS
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PART I

1				
2	U-21097	Northern States	Electric rate (settled)	Distribution capital
3		Power		
4				
5	U-21138	Consumers Energy	Complaint (withdrawn)	Distribution system
6				operations

DIRECT TESTIMONY OF NICHOLAS M. EVANS
CASE NUMBER U-21870
PART II

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

2 A. The purpose of my testimony is to present the Michigan Public Service Commission
3 Staff's (Staff) recommendations regarding Consumers Energy Company's (Consumers or
4 the Company) Distribution Deferral Mechanism, the proposed modifications to the
5 Investment Recovery Mechanism, and the proposed modification to service connection
6 tariffs.

7 Q. Are you sponsoring any exhibits?

8 A. No.

9 **Distribution Deferral Mechanism**

10 Q. Did the Company have actual capital spending for new business, reactive demand
11 failures, and asset relocations that were above the amounts included in rates?

12 A. Yes, for the time period of March 1, 2024 to February 28, 2025, as shown in Company
13 exhibit A-84 (PDD-60), page 2.

14 Q. For March 1, 2024 to February 28, 2025, what is the return on, return of, and property tax
15 related to the capital spending above the amounts included in rates for these three
16 programs?

17 A. \$24.3 million. Company exhibit A-84 (PDD-60) shows the calculations.

18 Q. Does Staff consider this amount to be reasonable and prudent?

19 A. Yes.

20 Q. Did the Company request continuation of the deferral mechanism proposed in MPSC
21 Case No. U-21585?

DIRECT TESTIMONY OF NICHOLAS M. EVANS
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1 A. Yes. Staff supports this request, as the capital spending associated with the distribution
 2 deferral mechanism was reviewed and found to be prudent. However, Staff recommends
 3 continuing the following conditions:

4 1. The Company shall provide a list of sub-programs and investment
 5 categories within each of the five programs of New Business, Demand Failures,
 6 Asset Relocation, Reliability, and Line Clearing and communicate any significant
 7 changes to these sub-programs and investment categories to Staff while the
 8 changes are still in the planning stages and prior to the implementation of the
 9 proposed changes.

10 2. The Company shall provide quarterly spend reporting in each of the five
 11 programs throughout the test year and notify Staff of any anticipated spending
 12 above 110% of the approved spend amount for New Business, Demand Failures,
 13 and Asset Relocation programs. Each notification must include an explanation for
 14 the overspend.

15 3. The Company shall spend the full amounts approved by the Commission
 16 in the Line Clearing programs. If the Company spends the approved amounts in
 17 the Line Clearing programs, deferred accounting treatment shall be authorized for
 18 both the overspend and the underspend (two-way tracker). If the Company fails
 19 to spend the approved amounts in the Line Clearing program, deferred accounting
 20 treatment shall only be authorized for the underspend (one-way tracker).

21 4. Deferred accounting treatment, if sought by the Company again in the future, must be
 22 requested in a future rate case.¹

23 Q. In direct testimony on page 39, lines 15-16, Company witness Patrick D. Daly states that
 24 the Company is requesting straight-line amortization of the associated regulatory
 25 asset balance. Did the Company provide more context to this proposal?
 26

27 A. Yes. In an audit response, Company witness Daly stated that recovery of any resulting
 28 regulatory asset balance, should the Company's proposal be approved, would be
 29

¹ These conditions were approved by the Commission in the Company's previous rate case. See March 21, 2025 Commission order in Case No. U-21585, pp. 381-382.

DIRECT TESTIMONY OF NICHOLAS M. EVANS
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PART II

requested in a future rate case and the Company would request that a 12-month surcharge be established to collect any resulting regulatory asset balance.

Investment Recovery Mechanism

Q. Please describe what the Company is proposing regarding its investment recovery mechanism (IRM) for this case.

A. The Company is proposing to extend the IRM for two years, from May 1, 2026 to April 30, 2028, at the following investment levels per year:

FIGURE 31

PROPOSED IRM EXPENDITURES

Sub-Program/ Investment Category	Proposed IRM Expenditure
Lines Reliability – LVD <i>(Targeted Circuit Improvements and Pole Replacements)</i>	\$276,191,000
Resiliency – Fractionalization	\$11,647,000
System Protection	\$4,098,000
Repetitive Outages - LVD	\$30,344,000
Vulnerable Communities	\$30,000,000
Total	\$352,280,000

Another table, taken from Company Exhibit A-163 (HJM-1), shows spending for each year:

² Figure 31, Company witness Michael P. Kelly Direct Testimony, p. 102.

DIRECT TESTIMONY OF NICHOLAS M. EVANS
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Line No.	Description	12 Mos. End 4/30/27	12 Mos. End 4/30/28	Source
	(a)	(b)	(c)	(e)
	<u>Capital Investment⁽¹⁾</u>			
1	Lines Reliability - LVD	276,191	276,191	
2	Resiliency	11,647	11,647	
3	System Protection	4,098	4,098	
4	Repetitive Outages	30,344	30,344	
5	Vulnerable Communities	30,000	30,000	
6	Total IRM Capital Investment	352,280	352,280	Sum Lines 1-5

Q. What is Staff recommending for May 1, 2026 - April 30, 2027 and May 1, 2027 – April 30, 2028?

A. Staff recommends approving the two-year extension of the IRM, covering May 1, 2026 – April 30, 2028, but with the following changes:

1) Due to a recommended adjustment from Staff witness Ryan Boutet to the Repetitive Outages sub-program, \$6,068,800 should be removed from the IRM each year;

2) the Vulnerable Communities sub-program should be removed from the IRM and the associated \$30,000,000 of proposed IRM expenditures placed into rate base for the test year;

3) For May 1, 2027 – April 30, 2028, the rate of return associated with the IRM surcharge should be lower than the pretax rate of return (ROR) as ordered in this instant case, but no lower than the short-term debt rate (STD) ordered in the instant case. Once these investments are found to be prudent and reasonable for inclusion in base rates in a future rate case, Staff intends for the normal ROR to apply.

DIRECT TESTIMONY OF NICHOLAS M. EVANS
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PART II

1 Q. Staff witness Ryan Boutet is recommending a disallowance of \$6,068,000 to the
2 Repetitive Outages sub-program for the test year, so that amount must be removed from
3 the IRM for the May 1, 2026 – April 30, 2027 year. But why is Staff recommending that
4 \$6,068,800 be removed from the IRM for the following 12-month period as well?

5 A. The \$6,068,000 disallowance is 20% of the test year projection for this sub-program.
6 The test year projection and the amount being requested for May 1, 2027 – April 30,
7 2028 are the same: \$30,344,000. In his direct testimony, Staff witness Boutet explains
8 that the 20% adjustment is a compromise between recent underspending by the Company
9 in this sub-program and the Commission's position in the last rate order that this sub-
10 program is valuable to the Company's CEMI-4 performance. Staff's concerns about
11 underspending apply to years beyond the test year, so Staff recommends that \$6,068,000
12 be removed from the IRM for May 1, 2027 – April 30, 2028 as well.

13 Q. Why does Staff recommend the Vulnerable Communities program be removed from the
14 IRM and the associated \$30,000,000 be placed into rate base?

15 A. Staff recommends placing the Vulnerable Communities program into rate base because,
16 as stated by Company witness Michael P. Kelly, on a systemwide basis, the Company's
17 Environmental Justice (EJ) communities have comparatively good reliability, even
18 though particular EJ communities do face reliability challenges. The Company should
19 invest in these communities, but recovery of those expenditures does not need to occur
20 through the IRM.

21 Q. Why is Staff recommending a lower rate of return for the IRM year of May 1, 2027 –
22 April 30, 2028?

DIRECT TESTIMONY OF NICHOLAS M. EVANS
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1 A. For numerous years, it appears the Company under-invested in its distribution system.

2 This is evident when examining what the Company spent years ago and what it is
 3 projecting to spend now and over the next several years. In the 2010s, the Company
 4 invested the following amounts in its distribution system:

5 2010: \$289,222,000³
 6 2011: \$323,266,000⁴
 7 2013: \$363,383,000⁵
 8 2014: \$337,340,000⁶
 9 2015: \$352,395,000⁷
 10 2016: \$419,535,000⁸
 11 2017: \$447,874,000⁹
 12 2018: \$533,167,000¹⁰
 13

14 In contrast, the Company is projecting to spend \$1,152,221,000 in 2025 and
 15 \$1,529,914,000 during the 12 months ending 4/30/2027 on distribution plant.¹¹ In its
 16 Reliability Roadmap (2025-2029), filed in the instant case as Exhibit A-129 (MPK-19),
 17 the Company projected the following amounts for 2025-2029:

³ MPSC Case No. U-16794, Exhibit A-13 (JRA-2), l. 8.

⁴ MPSC Case No. U-17087, Exhibit A-13 (JRA-2), l. 8.

⁵ MPSC Case No. U-17735, Exhibit A-52 (MPP-2), l. 8.

⁶ MPSC Case No. U-20697, Exhibit A-29 (RTB-2), l. 56.

⁷ MPSC Case No. U-20697, Exhibit A-29 (RTB-2), l. 56.

⁸ MPSC Case No. U-20697, Exhibit A-29 (RTB-2), l. 56.

⁹ MPSC Case No. U-20697, Exhibit A-29 (RTB-2), l. 56.

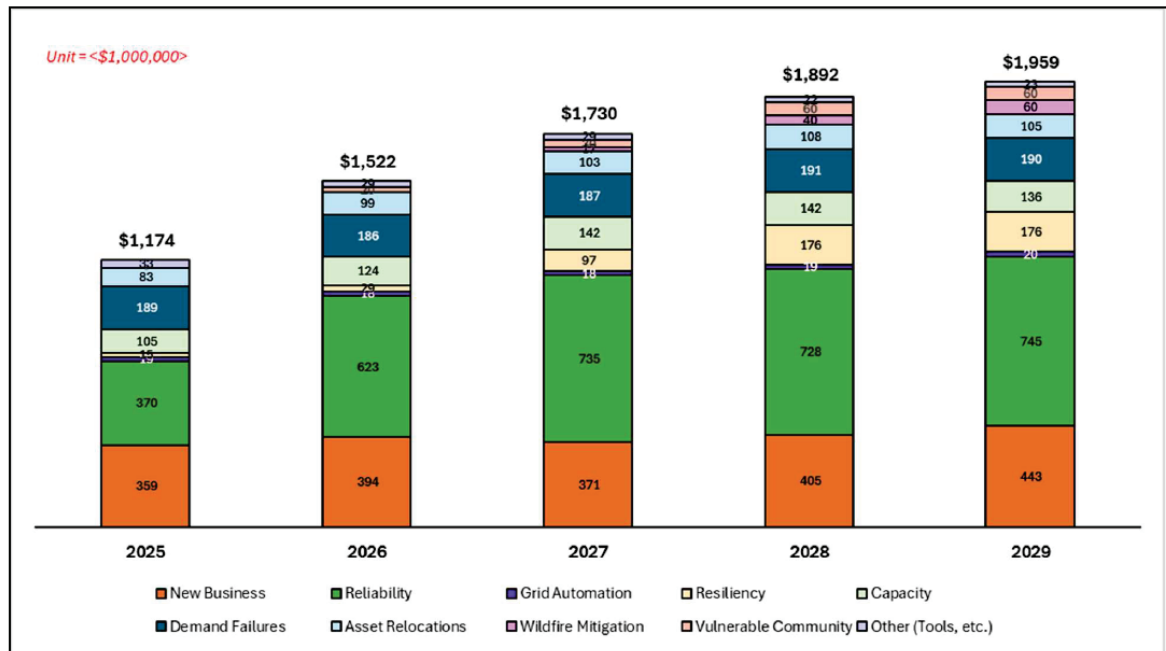
¹⁰ MPSC Case No. U-20697, Exhibit A-29 (RTB-2), l. 56.

¹¹ MPSC Case No. U-21870, Exhibit A-113 (MPK-3), p. 1.

DIRECT TESTIMONY OF NICHOLAS M. EVANS
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PART II

1

FIGURE 138
INVESTMENT PLAN (2025-2029)



2

3

4 The fact that distribution capital projections for the late 2020s are 4-6 times larger than
 5 the spending that occurred in most of the 2010s points to the earlier spending being
 6 insufficient. And while Staff is not claiming the projections for 2026-2029 are the
 7 correct amounts, they are probably closer in magnitude to what the system requires than
 8 the amounts that were spent a decade before and earlier. This indicates past under-
 9 investment in the distribution system that the Company has only recently begun to turn
 10 around.

11 Q. Is this recommendation regarding the rate of return that should be applied to the IRM
 12 similar to what you are recommending in Case No. U-21860, the ongoing DTE Electric
 13 rate case?

DIRECT TESTIMONY OF NICHOLAS M. EVANS
CASE NUMBER U-21870
PART II

1 A. Yes.

2 Q. Do you have any other recommendations for the Commission regarding the IRM
3 spending?

4 A. If the Commission thinks two years is too long a time period to approve, it can always
5 approve just one year. In addition, Staff is of the opinion that the Commission can reduce
6 a year's approved amounts later in a subsequent rate case prior to that year occurring.

7 **Tariff Changes**

8 Q. What changes to the new service connection fees is the Company proposing?

9 A. As shown in Company exhibit A-16 (BAG-2), Schedule F-5, pages 6, 10, 11, 13, and 14,
10 the Company is proposing the following tariff changes:

11 1. For original installations of underground service connections from underground
12 distribution systems, for mobile home parks, the non-refundable contribution in aid of
13 construction (CIAC) shall be a flat fee of \$1,300, which is change from the current \$4.50
14 per foot of required trench.

15 2. For installations of overhead service connections for residential customers, the
16 developer or customer shall make a non-refundable contribution of \$1,300. There
17 currently is no fee for these connections.

18 3. For installations of overhead service connections for general service customers,
19 the developer or customer shall make a refundable contribution of \$2,200. There
20 currently is no fee for these connections.

21 4. For the installation of underground service connections for residential customers,
22 the developer or customer shall make a non-refundable contribution of \$1,300. The
23 current contribution is \$350 for the first 150 feet and \$4.50 for each additional foot.

DIRECT TESTIMONY OF NICHOLAS M. EVANS
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PART II

1 5. For the installation of underground service connections for general service
2 customers, the developer or customer shall make a refundable contribution of \$2,200.
3 The current contribution is \$6.50 per trench foot.

4 Consumers proposes in each case that the flat fee applies to the route selected by
5 the Company, and for an alternate route requested by the customer and mutually agreed
6 upon by the Company and the customer, the contribution shall be the flat fee plus any
7 additional costs in excess of those associated with the route specified by the Company.

8 Q. Does Staff agree with these changes?

9 A. Only some of them. Staff agrees that the costs need to be updated, overhead service
10 connections should require the customer or developer to pay a fee, and the Company can
11 charge additional costs for alternate routes that are longer and more challenging.
12 However, Staff does not agree with the flat fee structure.

13 Q. Why does Staff not agree with the flat fee structure?

14 A. The Company calculated the \$1,300 and \$2,200 amounts based on a three-year average
15 service connection length of 132 feet multiplied by updated per-foot costs. Staff is
16 concerned that customers with service connection lengths shorter than 132 feet would be
17 subsidizing customers with much longer service connection lengths. Staff recommends
18 the Company maintain the existing fee structure in which there is a per foot charge for
19 each type of connection. For installations of overhead service connections for residential
20 and general service customers, which currently do not have fees, the Company should
21 propose fees or contributions that include per-foot charges in its next rate case.

22 Q. Please summarize your recommendations.

23 A. My recommendations are as follows:

DIRECT TESTIMONY OF NICHOLAS M. EVANS
CASE NUMBER U-21870
PART II

1 1. Staff supports recovery of the return on, return of, and property tax related to the
2 capital spending above the March 1, 2024 - February 28, 2025 amounts included in rates
3 for the new business, reactive demand failures, and asset relocations programs. This
4 amount equals \$24.3 million.

5
6 2. Staff supports continuation of the deferral mechanism, with conditions.
7

8 3. Staff recommends approving the two-year extension of the IRM, covering May 1,
9 2026 – April 30, 2028, but \$6,068,800 should be removed from the Repetitive Outages
10 program for each year and the Vulnerable Communities program should be removed
11 from the IRM and the associated \$30,000,000 of proposed IRM expenditures should be
12 placed into rate base. For May 1, 2027 – April 30, 2028, the rate of return associated with
13 the IRM surcharge should be lower than the pretax rate of return as ordered in this instant
14 case, but no lower than the short-term debt rate ordered in the instant case.
15

16 4. Staff does not agree with the flat fee structure proposed for new service
17 connection fees. The Company should maintain the existing fee structure in which there
18 is a per foot charge for each type of connection. For installations of overhead service
19 connections for residential and general service customers, the Company should propose
20 fees or contributions that include per-foot charges in its next rate case.
21

22 Q. Does this conclude your direct testimony?

23 A. Yes.

**In the matter of the application of
CONSUMERS ENERGY COMPANY
for authority to increase its rates for the
generation and distribution of electricity
and for other relief.**

October 21, 2025

**REBUTTAL TESTIMONY OF NICHOLAS M. EVANS
CASE NUMBER U-21870**

1 Q. Are you the same Nicholas M. Evans who filed direct testimony on behalf of
2 Michigan Public Service Commission (MPSC or Commission) Staff (Staff) in the
3 instant case?

4 A. Yes.

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

6 A. The purpose of my rebuttal testimony is to provide a general response to several
7 recommendations from intervenors regarding the Investment Recovery
8 Mechanism (IRM).

9 Q. Can you provide a summary of the IRM recommendations from intervenor
10 witnesses?

11 A. Yes. ABATE witnesses Colin Fitzhenry and James Dauphinais both recommend
12 the Commission reduce the Company's proposed annual authorized capital
13 expenditure amount for the LVD Lines Reliability sub-program for Year 3
14 (twelve months ending April 30, 2027) and Year 4 (twelve months ending April
15 30, 2028) of the IRM by at least \$108.8 million per year. METC witness Michael
16 Fleck stated that METC supports Consumers' inclusion of vulnerable
17 communities in the IRM. Sergio Cira-Reyes, testifying on behalf of the Urban
18 Core Collective, stated that he has concerns about approving another increase in
19 IRM spending before reconciliation of the current two-year IRM has been
20 completed, and he also recommends the Company report more thoroughly on the
21 linkage between the percentage of the investments in EJ communities relative to
22 the needs of those communities.

23 Q. Does Staff agree with these proposed adjustments?

**REBUTTAL TESTIMONY OF NICHOLAS M. EVANS
CASE NUMBER U-21870**

1 A. For the most part, no. In contrast to the large IRM reductions being
2 recommended by ABATE and UCC, Staff recommends the reductions be more
3 modest. Staff also does not support the Vulnerable Communities program being
4 added to the IRM. However, Staff does not oppose the Company being required
5 to report more thoroughly on the linkage between the percentage of the
6 investments in EJ communities relative to the needs of those communities.

7 Staff's adjustments are summarized in my direct testimony on page 17:

8 Staff recommends approving the two-year extension of the IRM, covering
9 May 1, 2026 – April 30, 2028, but \$6,068,800 should be removed from the
10 Repetitive Outages program for each year and the Vulnerable
11 Communities program should be removed from the IRM and the
12 associated \$30,000,000 of proposed IRM expenditures should be placed
13 into rate base. For May 1, 2027 – April 30, 2028, the rate of return
14 associated with the IRM surcharge should be lower than the pretax rate of
15 return as ordered in this instant case, but no lower than the short-term debt
16 rate ordered in the instant case.

17
18 Q. Does this conclude your rebuttal testimony?

19 A. Yes.

1 MR. SONNEVELDT: Next, Your Honor, Staff moves
2 to bind in the direct testimony of Laura Maio. Her direct
3 testimony consists of a cover sheet and 13 pages of
4 questions and answers. She sponsors exhibits S-8.0
5 through S-8.8.

6 JUDGE THOITS: Are there any objections to the
7 admission of this testimony or these exhibits?

8 Hearing none. The direct testimony of Laura
9 Maio is bound in the record in Exhibits 8.0 -- or excuse
10 me, S-8.0 through S-8.8 are admitted.

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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 generation and distribution of)
electricity and for other relief.)
_____)

Case No. U-21870

QUALIFICATIONS AND DIRECT TESTIMONY OF
LAURA MAIO
MICHIGAN PUBLIC SERVICE COMMISSION

September 30, 2025

QUALIFICATIONS OF LAURA MAIO
CASE NUMBER U-21870
PART I

1 Q. Please state your name and business address.

2 A. My name is Laura Maio, and my business address is 7109 West Saginaw Highway,
3 Lansing, Michigan 48917.

4 Q. Ms. Maio, where are you currently employed and in what position?

5 A. In 2023, I was hired by the Michigan Public Service Commission (MPSC or
6 Commission) as a Public Utilities Engineer in the Energy Cost Recovery &
7 Generation Operations Section within the Energy Operations Division.

8 Q. What are your responsibilities in your current position?

9 A. I perform technical analyses and reviews in Act 304 natural gas and electric plan
10 and reconciliation cases. In these proceedings, I evaluate gas cost recovery (GCR)
11 and power supply cost recovery (PSCR) plans and reconciliations and develop
12 MPSC Staff's (Staff) position regarding the related issues. In addition, I review the
13 average cost of natural gas sold, gas in underground storage, and GCR costs in
14 natural gas rate cases as well as generation-related operation and maintenance
15 expenses (O&M), capital expenditures, and PSCR costs in electric rate case
16 proceedings.

17 Q. Would you outline your educational background and work experience?

18 A. I earned a Licenciado Degree in Mechanical Engineering from the Faculty of
19 Engineering, at the University of Porto, Portugal; a Licenciado Degree in
20 Criminology from the University of Maia, Portugal; and a Master of Science from
21 the University of Porto, Faculty of Law in Porto, Portugal. In Portugal, I worked as
22 a Mechanical Engineer and Project Manager, for 5 years, with Finerge, a
23 Portuguese energy developer and project management firm, among other roles. At

QUALIFICATIONS OF LAURA MAIO
CASE NUMBER U-21870
PART I

1 Finerge, I performed root cause analyses on underperforming power plants,
2 implemented and managed power plant development projects, and performed
3 economic and technical feasibility studies. In the United States, prior to my
4 employment at the MPSC, I worked as an IT Remote Support Systems Technician
5 with Centaris in Sterling Heights, Michigan, where I handled first-level IT support
6 service requests, among other responsibilities. Previously, I worked for Rochester
7 Community Schools as a Paraeducator and Tech Assistant. Since being hired by
8 the MPSC, I have attended the Rate Case Basics course held by National
9 Association of Regulatory Utility Commissioners (NARUC), the Natural Gas
10 Utilities 101 Course hosted by Electric Utility Consultants, Inc. (EUCI), the
11 WPUI's Regional Transmission Organization (RTO) Fundamentals program held
12 by Wisconsin Public Utility Institute, the Electric Utilities 101 Course hosted by
13 EUCI, the IPU (Institute of Public Utilities) Power Grid School Course held by
14 IPU, the IPU Annual Regulatory Studies Program - The Fundamentals Course held
15 by IPU, the Basics of Utility Accounting and Ratemaking course held by NARUC,
16 the Electricity 101 course held by NARUC, and the Natural Gas Physical &
17 Financial Markets course hosted by EUCI.

18 Q. Have you previously presented testimony with this Commission?

19 A. Yes, I have filed testimony in the following cases:

20 U-21389, Consumers Energy's 2023 Electric Rate Case.

21 U-21067, Michigan Gas Utilities Corp. 2022-2023 GCR Reconciliation Case

22 U-21445, SEMCO 2024-2025 GCR Plan Case

23 U-21441, Michigan Gas Utilities Corp. 2024-2025 GCR Plan Case

QUALIFICATIONS OF LAURA MAIO
CASE NUMBER U-21870
PART I

1	U-21540, Michigan Gas Utilities Corp. 2024 Gas Rate Case
2	U-21274, Michigan Gas Utilities Corp. 2023-2024 GCR Reconciliation Case
3	U-21612, Northern States Power Company 2025-2026 GCR Plan Case

DIRECT TESTIMONY OF LAURA MAIO
CASE NUMBER U-21870
PART II

1 Q. What is the purpose of your testimony?

2 A. The purpose of my testimony is to present the MPSC Staff's adjustments to
3 Consumers Energy Company's (Consumers Energy or the Company) generation
4 capital expenditures and operations and maintenance (O&M) expenses. In addition,
5 I am supporting an increase to the Power Supply expenses that is a result of Staff's
6 adjustment to the Company's sales forecast.

7 Q. Are you sponsoring any exhibits?

8 A. Yes, I am sponsoring the following exhibits:

9 - Exhibit S-8.0: Consumers Energy's Response to Discovery Request ST-CE-0002
10 and Attachment U21870-ST-CE-0002_ATT_0001, modified on page 3 to show
11 Staff's calculation

12 - Exhibit S-8.1: Staff's Summary of Recommended Adjustments to Fossil-fueled
13 and Hydro Pumped Storage Generation Capital Expenditures related to
14 Consumers Energy's Updated Projected Amounts in the Bridge Period

15 - Exhibit S-8.2: Consumers Energy's Response to Discovery Request ST-CE-0003
16 and Attachment U21870-ST-CE-0003_ATT_0001, Copy of the Current Version
17 of the Company's Internal Cost Estimating Guidelines, EPMO (Enterprise
18 Project Management Office) Cost Estimating Manual

19 - Exhibit S-8.3: Consumers Energy's Response to Discovery Request ST-CE-0005
20 and Attachment U21870-ST-CE-0005_0001, Updated Class Cost Estimate

21 - Exhibit S-8.4: Staff's Summary of Recommended Adjustments to Fossil-fueled
22 and Hydro Pumped Storage Generation Capital Expenditures related to the Class
23 Cost Estimate Assigned to each Project

DIRECT TESTIMONY OF LAURA MAIO
CASE NUMBER U-21870
PART II

1 - Exhibit S-8.5: Consumers Energy's Response to Discovery Request ST-CE-0018,
2 Workpaper WP-RTB-24 and Workpaper WP-RTB-13, page 1

3 - Exhibit S-8.6: Consumers Energy's Response to Discovery Request ST-CE-0192

4 - Exhibit S-8.7: Consumers Energy's Response to Discovery Request ST-CE-0231

5 - Exhibit S-8.8: Consumers Energy's Response to Discovery Request ST-CE-0015

6 Q. Were these exhibits prepared by you?

7 A. Yes, these exhibits were prepared by me from data supplied by the Company in
8 their initial filing and in response to Staff discovery requests.

9 Q. What Generation capital expenditures and Generation O&M expenses were you
10 responsible for reviewing in this case?

11 A. I am responsible for reviewing the Company's Fossil-fueled and Hydro Pumped
12 Storage Generation capital expenditure projects. Projects related to the Battery
13 Storage in the bridge period and test year are covered in testimony by Staff witness
14 Marcy Champion. With respect to Generation O&M expenses, I am responsible for
15 reviewing the Company's Fossil-fueled and Hydro (River and Pumped Storage)
16 O&M expenses. Staff's position on the one-way tracker for the River Hydro O&M
17 expenses, requested by the Company in this filing, is covered in testimony by Staff
18 witness Shannon Rueckert.

19
20 **Fossil-fueled and Hydro Pumped Storage Generation Capital Expenditures**

21 Q. Please describe Staff's adjustments to Fossil-fueled and Hydro Pumped Storage
22 Generation capital expenditures.

DIRECT TESTIMONY OF LAURA MAIO
CASE NUMBER U-21870
PART II

1 A. Staff is recommending two categories of adjustments to Fossil-fueled and Hydro
2 Pumped Storage Generation capital expenditures related to: 1) the use of updated
3 projections for capital projects over \$1 million in the bridge period; and 2) a
4 reduction to capital projects over \$1 million in the test year based on the class cost
5 estimate for certain projects.

6 Q. Please describe Staff's first adjustment to Fossil-fueled and Hydro Pumped Storage
7 Generation capital expenditures in the bridge period.

8 A. In response to discovery, the Company provided Staff with actual amounts through
9 June 2025 as well as updated capital expenditure projections for Generation capital
10 projects over \$1 million as described in Exhibit A-12 (RTB-3), Schedule B-5.2,
11 page 8. See Exhibit S-8.0. From this data, Staff calculated the difference between
12 the amounts originally filed in this case compared to the actual/updated amounts
13 provided in response to the discovery for the bridge period. Consumers Energy's
14 updated amounts result in an overall reduction to Generation capital expenditures
15 of \$5.453 million in the bridge period. The total difference/reduction as well as the
16 differences for individual projects can be found in Staff's Exhibit S-8.1 for the
17 bridge period. Based on the Company's actuals and updated projections, Staff
18 recommends the removal of \$5.453 million in capital expenditures for the bridge
19 period for capital projects over \$1 million as identified in Exhibit A-12 (RTB-3),
20 Schedule B-5.2, page 8.

21 Q. Please describe Staff's second and last adjustment to Fossil-fueled and Hydro
22 Pumped Storage Generation capital expenditures in the test year.

DIRECT TESTIMONY OF LAURA MAIO
CASE NUMBER U-21870
PART II

A. The second and last adjustment Staff recommends is related to the Company's cost class estimates for each project. Consumers Energy assigns its own internal cost class estimate standard to each capital project over \$1 million, which is adapted from the Association for the Advancement of Cost Engineering (AACE) International estimating classes. In response to a Staff discovery request, the Company provided its Enterprise Project Management Organization Cost Estimating Manual, see Exhibit S-8.2. This document describes Consumers Energy's internal cost class estimate standards. As shown in Table 1 below, costs are classified from 1 to 5 (2nd Column), with 1 being the most defined and 5 being the least defined (extracted from Exhibit S-8.2, page 3).

	Project Gate & Stage	Estimate Type (Class)	Engineering Complete	Expected Accuracy Range (Not contingency amount)	End Usage of Estimate
0	Business Case	ROM (Class 5)	0 - 2% Feasibility Studies	-50% to +100%	Concept Screening Alternative Analysis
1	Initiation	Conceptual (Class 4)	1 - 15% Conceptual Engineering	-30% to +50%	LTFP Approval Authorization of spend for initial gates Project Authorization
2	Project Plan & Scope Definition	Budgetary (Class 3)	15 - 50% Front End Engineering	-10% to +25%	Baseline for Project Cost Performance
3	Final Engineering & Planning	Definitive (Class 2)	80 - 100% Detailed Engineering	-10% to +5%	Authorization for Construction Full authorization by Board of Directors where applicable
4	Execution, Startup, Test & Commission	Control (Class 1)	100% Engineering Field Support	-5% to +5%	Reforecasting Estimate at Completion (EAC) Estimating and Challenging Change Orders
5	Closeout	N/A	100% Engineering Closeout	0%	Final Project Performance Benchmarking Estimating Process Improvement Development of Unit Cost Data

Table 1 – Consumers Energy's Cost Estimate Classes

Q. Please describe how Staff analyzed each project cost estimate based on the class cost estimate types established by Consumers Energy.

DIRECT TESTIMONY OF LAURA MAIO
CASE NUMBER U-21870
PART II

1 A. The Company's cost class estimates for its capital projects allow Staff to have a
2 better understanding of the level of development and certainty associated with each
3 specific project cost estimate that Consumers Energy is requesting recovery of in
4 this case. From these guidelines, Staff concludes that the further into the future a
5 projected amount is estimated for a project indicates that the cost estimate is more
6 uncertain. For this reason, Staff adjusted certain projects over \$1 million in the test
7 year for which the engineering component was not one hundred percent known. In
8 addition, in previous orders, the Commission has ruled in favor of the inclusion of
9 adjustments related to the Company's cost class estimates for some projects over
10 \$1 million in the test year. For instance, the order in MPSC Case No. U-21585
11 stated:

12 With respect to the Staff's proposed adjustments based on cost class
13 estimates, the Commission agrees with the Staff's analysis and adopts the
14 findings and recommendations of the ALJ. The Commission finds that the
15 Staff's proposal to use the lower bounds of the cost class estimates' ranges
16 only applies to certain projects that exceed \$1 million dollars and finds that
17 some proportion of the total projects is likely to land at the low end of the
18 company's class estimate ranges. [MPSC Case No. U-21585, March 21,
19 2025 order, pp. 128, 129.]
20

21 Therefore, to make the adjustment for some projects over \$1 million in the test
22 period, Staff used the lower bound of the expected accuracy range for each class
23 estimate level. From Table 1, the adjusted projects may have class estimates of
24 two, three, four, or five (2nd Column – Estimate Type) and a lower bound of minus
25 ten percent, minus ten percent, minus thirty percent, and minus fifty percent,
26 respectively (4th Column – Expected Accuracy Range). Before making an
27 adjustment, Staff requested, through discovery, updates of the projected amounts,

DIRECT TESTIMONY OF LAURA MAIO
CASE NUMBER U-21870
PART II

1 of which no updates were made to the projected amounts in the test year (Exhibit
2 S-8.0), and the class cost estimate (Exhibit S-8.3) for all projects to make an
3 adjustment to the most up-to-date information. Staff's adjustments are shown
4 individually and in total on Exhibit S-8.4.

5 Q. What amount is Staff recommending be removed from this case in the test year
6 based on the level of uncertainty in the class cost estimate of each project?

7 A. Staff recommends the removal of \$7.455 million in capital expenditures for the test
8 year based on the class cost estimate assigned to each project.

9 Q. Please summarize Staff's recommendations to Fossil-fueled and Hydro Pumped
10 Storage Generation Capital Expenditures in the bridge period and test year.

11 A. Based upon Staff's review, Staff is recommending the removal of \$5.453 million
12 in capital expenditures for the bridge period (16-month bridge period beginning
13 January 1, 2025, and ending April 30, 2026), and the removal of \$7.455 million for
14 the test year ending April 30, 2027.

15

16 **Generation O&M Expenses**

17 Q. Please provide an overview of Staff's recommended adjustment to the Company's
18 Generation O&M Expenses.

19 A. Staff is recommending one adjustment to the Base O&M expense
20 component/category of the Company's Total Generation O&M Expenses. This
21 adjustment is attributed to the removal of the Emergent Reliability Funding expense
22 from the Admin/Generation Commons expense included in the Base O&M expense
23 category.

DIRECT TESTIMONY OF LAURA MAIO
CASE NUMBER U-21870
PART II

1 Q. Please describe Staff's adjustment to the Admin/Generation Commons expense
2 included in the Base O&M expense category of Generation O&M expense shown
3 on Exhibit A-43, page 1.

4 A. In response to discovery (refer to Exhibit S-8.5), Consumers Energy identified the
5 expense categories and respective amounts included in the Admin/Generation
6 Commons expense in the Base O&M expense category. From this information,
7 Staff requested through discovery (Exhibit S-8.6) for Consumers Energy to explain
8 the Emergent Reliability Funding expense of \$2.849 million as well as its benefits,
9 needs and historical amounts. In response, the Company stated:

10 The Emergent Reliability Funding expense represents an allocation of
11 O&M funding designated for electric generation sites to address unforeseen
12 reliability issues that arise during the test year. These emergent items are
13 not included in detailed maintenance due to their unpredictable nature.
14 Examples include unplanned equipment failures, urgent environmental
15 compliance needs, or other reliability related corrective actions that are
16 critical to maintaining safe and reliable generation operations. Emergent
17 Reliability Funding is not a new funding item; rather, it is budgeted annually
18 and is necessary in the test year to fund emergent issues as they arise. There
19 are no actual costs in the historical year of 2024 because those funds, when
20 spent, are allocated to specific plants/units upon investment in the
21 Operations areas. The amount of the Emergent Reliability Funding utilized
22 for the prior three years (2022 through 2024) was \$6.094 million, \$3.246
23 million, and \$8.346 million respectively. The inclusion of this funding in
24 the test year is necessary to ensure that electric generation sites maintain
25 high reliability standards despite the inherent uncertainty of emergent
26 issues. As generation assets age and operational demands evolve, the
27 likelihood of unplanned reliability events increases. This funding provides
28 flexibility to address such events promptly, ensuring compliance, safety,
29 and service reliability for customers. [Exhibit S-8.6, p. 1.]

30
31 Additionally, the Company confirmed (refer to Exhibit S-8.7) that the Emergent
32 Reliability Funding expense of \$8.346 million, spent in 2024, is included in the
33 historical expense (2024) in Exhibit A-43 (RTB-4). Based on the Company's

DIRECT TESTIMONY OF LAURA MAIO
CASE NUMBER U-21870
PART II

1 explanations, Staff's understanding is that the Emergent Reliability Funding
2 expense of \$2.849 million is an increase to the Emergent Reliability Fund expense
3 of \$8.346 million already built in in the historical expense (2024). The Emergent
4 Reliability Fund expense of \$8.346 million, spent in the historical year, was already
5 inflated to forecast the projected test year Generation O&M expenses, as explained
6 by the Company (Direct Testimony of Richard Blumenstock, pp. 103-105, and
7 Exhibit S-8.8). In addition, the Emergent Reliability Fund expense of \$8.346
8 million is the highest Emergent Reliability Fund expense for the prior three years
9 (2022 through 2024). Therefore, there is no guarantee that the Company will spend
10 an additional \$2.849 million on Emergent Reliability Funding in the test year. For
11 these reasons, Staff recommends the removal of \$2.849 million related to the
12 Emergent Reliability Funding Expense included in the Admin/Generation
13 Commons expense, part of the Base O&M expense.

14 Q. What amount is Staff recommending be removed from Generation O&M expense
15 based on the review of the Admin/Generation Commons expenses included in the
16 Base O&M expense category of Generation O&M expense?

17 A. Staff recommends the removal of \$2.849 million related to the Emergent Reliability
18 Funding expense included in the Admin/Generation Commons expense since this
19 amount is in addition to the Emergent Reliability Fund expense already
20 incorporated in the historical expense (2024), and there is no assurance that this
21 additional requested amount is needed or will be spent in the test year.

22 Q. Please summarize Staff's recommend adjustments to Generation O&M Expenses.

DIRECT TESTIMONY OF LAURA MAIO
CASE NUMBER U-21870
PART II

1 A. Based upon Staff's review, Staff recommends that Consumers Energy's Generation
2 O&M expenses be reduced by \$2.849 million.

3
4 **Power Supply Expenses**

5 Q. Please explain Staff's adjustment to power supply expenses on Exhibit A-52
6 (EMB-6), page 1.

7 A. Staff is recommending an adjustment to Consumers Energy's sales forecast as
8 explained by Staff witnesses Madison Todd and Paul Ausum. Staff's increase in
9 the Company's sales forecast results in an increase in power supply revenues that
10 must be offset with a corresponding increase in fuel and purchased power expenses
11 to keep power supply costs equal to power supply revenues. This adjustment is
12 necessary so that power supply expenses do not have an impact on the revenue
13 deficiency in this rate case since they are reviewed and reconciled in the power
14 supply cost recovery cases. The amount that power supply costs need to be
15 increased by is \$12,228,188 and is calculated by multiplying the Staff's sales
16 adjustment (excluding the Choice sales adjustment) by the PSCR base at sales level.
17 (\$12,228,188 = 204,655.87 MWh * \$59.75/MWh).

18
19 Q. Does that complete your testimony?

20 A. Yes, it does.
21
22
23

1 MR. SONNEVELDT: Next, Your Honor, Staff moves
2 to bind in the direct testimony of Jacob G. Martus. His
3 direct testimony consists of a cover sheet and seven pages
4 of questions and answers. He also sponsors Exhibit S-
5 17.0.

6 JUDGE THOITS: Are there any objections to the
7 admission of this testimony or this exhibit?

8 Hearing none. The direct testimony of Jacob
9 Martus is bound to the record, and Exhibit S-17.0 is
10 admitted.

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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 electricity and for other relief.)
_____)

Case No. U-21870

QUALIFICATIONS AND DIRECT TESTIMONY OF
JACOB G. MARTUS
MICHIGAN PUBLIC SERVICE COMMISSION

September 30, 2025

QUALIFICATIONS OF JACOB G. MARTUS
CASE NUMBER U-21870
PART I

1 **Q. Please state your name, business address, and occupation.**

2 A. My name is Jacob G. Martus, and my business address is 7109 West Saginaw
 3 Highway, Lansing, Michigan. I am employed by the Michigan Public Service
 4 Commission (MPSC or Commission) as a Public Utility Engineer in the
 5 Infrastructure Section of the Gas Safety and Operations Division.

6 **Q. On whose behalf are you testifying?**

7 A. I am testifying on behalf of the MPSC Staff (Staff).

8 **Q. What is your educational background and work experience?**

9 A. I earned a Bachelor of Science degree in Mechanical Engineering from the
 10 University of Michigan in 2023. I began my employment with the MPSC in
 11 January 2024 as a Public Utilities Engineer. My responsibilities as a Public
 12 Utilities Engineer include engineering duties related to the Commission's
 13 regulation of natural gas well production and proration; transmission of natural
 14 gas, crude oil, and petroleum products by pipeline; underground natural gas
 15 storage; gas pipeline safety; compliance with gas technical standards, including
 16 review of gas utilities' meter testing programs; and various other gas utility
 17 functions, including review of gas utilities' customer attachment programs and
 18 complaints or inquiries related to those programs.

19 **Q. Have you participated in any other cases before the MPSC prior to this**
 20 **current proceeding?**

21 A. Yes. I have participated in the following cases before the MPSC:

22 Case No. Case Description

23 U-21291 DTE Gas Company gas rate case

QUALIFICATIONS OF JACOB G. MARTUS
CASE NUMBER U-21870
PART I

1 U-21490 Consumers Energy Company gas rate case
2 U-21540 Michigan Gas Utilities Corporation gas rate case
3 U-21624 SEMCO Energy Gas Company MRP and IRIP extension/amendment
4 U-21785 SEMCO Pipeline Company Belle River Pipeline Act 9 case
5 U-21825 SEMCO Energy Gas Company Mussey Township Act 69 case
6 U-21835 Consumers Energy Company C-1103 Well Line Act 9 case
7 U-21806 Consumers Energy Company gas rate case
8 U-21861 DTE Gas Company Lincoln Township Act 69 case
9 U-21862 DTE Gas Company Vergennes Township Act 69 case

10 **Q. Have you filed testimony before the MPSC in any of the aforementioned**
11 **cases?**

12 **A. Yes, I have filed testimony in case U-21806, Consumers Energy Company gas**
13 **rate case.**

DIRECT TESTIMONY OF JACOB G. MARTUS
CASE NUMBER U-21870
PART II

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

2 A. The purpose of my direct testimony in this proceeding is to provide Staff's
3 analysis and recommendations to the Commission regarding Consumers Energy
4 Company's (Consumers Energy or the Company) requested regulatory deferral
5 mechanism for the Staking and Locating sub-program. Additional Staff expert
6 witnesses may, or may not, provide additional analysis and recommendations
7 related to the topics contained in the direct testimony herein.

8 **Q. Are you sponsoring any exhibits in this proceeding?**

9 A. Yes, I am sponsoring the following exhibit:
10 Exhibit S-17.0: Consumers Energy's Audit Response U21870-SA-CE-138, is a
11 2-page exhibit which displays the Company's response to Staff's audit request
12 regarding the Company's possible fluctuation in staking volume.

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

14 A. Yes. These exhibits were prepared by me, or under my direction; however, some
15 of the source information contained in the exhibits was generated by others.

16 **Q. Which Company witness sponsored direct testimony pertaining to the**
17 **Company's Staking and Locating sub-program?**

18 A. Michael P. Kelly sponsored testimony pertaining to the spending of the Staking
19 and Locating sub-program.

20 **Q. Please briefly describe what expenditure the Company is proposing related**
21 **to the Staking and Locating sub-program, as sponsored by Company witness**
22 **Michael P. Kelly.**

DIRECT TESTIMONY OF JACOB G. MARTUS
CASE NUMBER U-21870
PART II

1 A. As shown on page 149 and Figure 49 of Company witness Michael P. Kelly's
2 testimony, the company is proposing an expenditure of \$13,948,218 for the test
3 year ending April 30, 2027.

4 **Q. Please briefly describe the staking volume the Company is proposing related**
5 **to the Staking and Locating sub-program, as sponsored by Company witness**
6 **Michael P. Kelly.**

7 A. As shown on page 150 and Figure 50 of Company Witness Michael P. Kelly's
8 direct testimony and on page 2 of the audit response shown in Exhibit S-17.0, the
9 Company is proposing a base unit ticket volume of 478,176 and base unit cost of
10 \$26.93/unit for the projected 2026 year and proposing a base unit ticket volume of
11 511,648 and base unit cost of \$27.81/unit for the projected 2027 year.

12 **Q. Please briefly describe the purpose of the Company's requested regulatory**
13 **deferral mechanism for the Staking and Locating sub-program, as sponsored**
14 **by Company witnesses Michael P. Kelly.**

15 A. As shown on pages 151 and 152 of Company witness Michael P. Kelly's
16 testimony, the Company has identified two projects (Realizing Opportunities with
17 Broadband Infrastructure Networks or "ROBIN" and Broadband Equity, Access,
18 and Deployment Program or "BEAD") which they assert can cause significant
19 fluctuations in the staking volume. Hence, the Company is requesting a regulatory
20 deferral mechanism to refund spending below or recover spending above the
21 amount in the rate case.

22 **Q. Has the Company made a similar regulatory deferral mechanism request for**
23 **its Staking and Locating sub-program in case U-21806?**

DIRECT TESTIMONY OF JACOB G. MARTUS
CASE NUMBER U-21870
PART II

1 A. Yes, as shown on page 152 of Michael P. Kelly's testimony, the Company has
 2 requested a similar regulatory deferral mechanism for its Staking and Locating
 3 sub-program in its gas rate case U-21806 due to the Company's concern of the
 4 "ROBIN" and "BEAD" projects introducing uncertainty in the staking ticket
 5 volume.

6 **Q. Does Staff have any concerns or recommendations regarding the Company's**
 7 **requested regulatory deferral mechanism for the Staking and Locating sub-**
 8 **program?**

9 A. Yes, Staff supports the use of a regulatory deferral mechanism for the Staking and
 10 Locating sub-program. However, Staff supports the use of a regulatory deferral
 11 mechanism for only fluctuations stemming from the variability in staking volume.
 12 Therefore, Staff recommends that the recovery and refund amount for the
 13 regulatory deferral mechanism for the test year ending April 30, 2025 be set by
 14 Equation 1 below where r_amount^1 is the recovery/refund amount, e_volume is
 15 the experienced ticket volume during the test year, p_volume is the projected
 16 ticket volume during the test year, and p_cost is the projected ticket unit cost
 17 during the test year.

$$\text{Equation 1: } r\_amount = (e\_volume - p\_volume) * p\_cost$$

19 Furthermore, the audit response shown in Exhibit S-17.0 of this testimony shows
 20 that the experienced ticket volume may fluctuate by -9.13% to +3.77% from the
 21 projected amount. Staff therefore recommends for e_volume from Equation 1 to

¹ A negative r_amount indicates a refund (e.g. $r\_amount = -\$15,000$ is a \$15,000 refund). Positive $r\_amounts$ indicate a recovery amount.

DIRECT TESTIMONY OF JACOB G. MARTUS
CASE NUMBER U-21870
PART II

1 be capped to that fluctuation range. This results in Equations 2 and 3 below where
2 c_recovery is the capped recovery amount for Equation 1 and c_refund is the
3 capped refund amount for Equation 1.

4 Equation 2: $c\_recovery = 0.0377 * p\_volume * p\_cost$

5 Equation 3: $c\_refund = 0.0913 * p\_volume * p\_cost$

6 **Q. If the Commission order were to approve a projected staking volume amount**
7 **and/or staking unit cost different from what Michael P. Kelly provided in**
8 **direct testimony, would Staff's recommendation for the Staking and**
9 **Locating sub-program regulatory deferral mechanism change?**

10 A. No, Staff's recommendation for the regulatory deferral mechanism is to use
11 Equations 1-3 which kept p_volume and p_cost in variable form. The equations
12 apply regardless of the projected staking volume and staking unit cost the
13 Commission approves for the test year.

14 **Q. Does Staff have any more discussion to convey regarding the aforementioned**
15 **recommendation for the Staking and Locating sub-program's requested**
16 **regulatory deferral mechanism?**

17 A. Yes, due to the similarities between the regulatory deferral mechanisms being
18 requested in this case and case U-21806, Staff provided similar recommendations
19 for both cases to allow for a regulatory deferral mechanism which is contingent
20 on experienced staking volumes. Case U-21806 is anticipated to have an order by
21 October 16, 2025, and if Staff's recommendation for U-21806 isn't adopted by
22 the Commission, Staff may consider withdrawing the recommendation contained
23 within this direct testimony.

DIRECT TESTIMONY OF JACOB G. MARTUS
CASE NUMBER U-21870
PART II

1 **Q.** Is there anything additional that Staff would like to discuss within this direct
2 **testimony?**

3 **A.** No.

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

5 **A.** Yes, it does.

1 MR. SONNEVELDT: Next, Your Honor, Staff moves
2 to bind in the direct testimony of Jing Shi. Ms. Shi's
3 testimony consists of a cover sheet and eight pages of
4 questions and answers. She sponsors no exhibits.

5 JUDGE THOITS: Any objection to the admission of
6 this testimony.

7 Hearing none. The direct testimony of Jing Shi
8 is bound into the record.

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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 generation and distribution of
electricity and for other relief**

Case No. U-21870

QUALIFICATIONS AND DIRECT TESTIMONY OF

JING SHI, P.E.

MICHIGAN PUBLIC SERVICE COMMISSION

September 30, 2025

QUALIFICATIONS OF JING SHI
CASE NUMBER U-21870
PART I

1 Q. Please state your name and business address.

2 A. My name is Jing Shi. My business address is 7109 W. Saginaw Highway,
3 Lansing, Michigan 48917.

4 Q. Where are you currently employed and in what position?

5 A. I was a Public Utilities Engineer in the Energy Cost Recovery and Generation
6 Operation Section from 2008 until my recent transfer to the Electric Operation
7 Section within the same Energy Operations Division, at the Michigan Public
8 Service Commission (MPSC or Commission).

9 Q. What are your responsibilities in your current position?

10 A. In my current position, I review and testify regarding the distribution system's
11 O&M and capital expenditures in rate cases. Before transferring, I performed
12 technical analyses and reviews in Act 304 electric plan and reconciliation
13 proceedings. In these cases, I evaluated power supply cost recovery (PSCR) plans
14 and reconciliations and developed MPSC Staff's (Staff) position regarding the
15 related issues. In addition, I also reviewed power plant production operation and
16 maintenance expenses (O&M), capital expenditures, sales forecasts, and PSCR-
17 related costs in rate case proceedings.

18 Q. Please describe your educational and training background.

19 A. I earned a bachelor's degree in civil engineering in Beijing, China, and a master's
20 degree in environmental engineering from Michigan State University (MSU). I
21 have also completed 80% of the required coursework for an associate degree in
22 accounting at Lansing Community College. Additionally, I have attended
23 numerous advanced regulatory sessions hosted by the Institute of Public Utilities

QUALIFICATIONS OF JING SHI
CASE NUMBER U-21870
PART I

1 (IPU) at MSU, the 2015 and 2023 Grid School, the 2019 Ratemaking Courses, as
2 well as recent training with Electric Utility Consultants, Inc. (EUCI) on the topics
3 of Overhead / Underground Distribution Systems and the Fundamentals of
4 Distribution reliability. I have also attended training with The National
5 Association of Regulatory Utility Commissioners (NARUC) on the topics of
6 Distribution Equity Analysis, as well as with the National Association of State
7 Energy Officials (NASEO) and Lawrence Berkeley National Laboratory (LBNL)
8 on the topic of Distribution System Planning and Resilience while employed by
9 the MPSC.

10 Q. Please give a summary of your work experience before you are hired by the
11 MPSC.

12 A. I worked with the Michigan Biotechnology Institute (MBI); EFX, Inc.; and The
13 Retec, Inc. (all environmental remediation related companies) as a research
14 engineer after I graduated from MSU. During this period, my main work involved
15 studies of the removal of organic pollutants and other volatile organic compounds
16 from groundwater. I designed, constructed, and operated the pilot-scale reactors,
17 conducted chemical analyses, and prepared, presented, and published technical
18 papers in peer reviewed national journals and at national conferences.
19 In late 2002, I began accounting classes at Lansing Community College and
20 started working for The Pension Trend, LLC, and then later for The Rehmann
21 Group, Inc., as an Accounting Specialist. My responsibilities included
22 reconciling year-end balance sheets, complying with IRS rules, and building
23 client relationships. I also passed the RPF examination (Retirement Plan

QUALIFICATIONS OF JING SHI
CASE NUMBER U-21870
PART I

1 Fundamental) of ASPPA (The American Society of Pension Professionals &
 2 Actuaries).

3 Q. Do you have any licenses?

4 A. Yes. I am a registered Professional Engineer with the State of Michigan.

5 Q. Have you previously presented testimony before the MPSC?

6 A. Yes. I have presented testimony in the following rate and PSCR cases:

<u>Case No.</u>	<u>Company</u>	<u>Description</u>
U-15768	DTE Electric Company	Electric Rate Case
U-15981	Wisconsin Electric Power Company	Electric Rate Case
U-16166	UPPCO	Electric Rate Case
U-18014	DTE Electric Company	Electric Rate Case
U-18255	DTE Electric Company	Electric Rate Case
U-18403	DTE Electric Company	Electric PSCR Case
U-20221	DTE Electric Company	Electric PSCR Case
U-20561	DTE Electric Company	Electric Rate Case
U-20222	DTE Electric Company	Electric PSCR Recon
U-20527	DTE Electric Company	Electric PSCR Case
U-20528	DTE Electric Company	Electric PSCR Recon
U-20802	Consumers Energy	Electric PSCR Plan
U-21048	Consumers Energy	Electric PSCR Plan
U-21224	Consumers Energy	Electric Rate Case
U-21286	UPPCO Power Company	Electric Rate Case
U-20803	Consumers Energy	Electric PSCR Rec.

QUALIFICATIONS OF JING SHI
CASE NUMBER U-21870
PART I

1	U-21257	Consumers Energy	Electric PSCR Plan
2	U-21297	DTE Electric Company	Electric Rate Case
3	U-21389	Consumers Energy	Electric Rate Case
4	U-21049	Consumers Energy	Electric PSCR Rec
5	U-21585	Consumers Energy	Electric Rate Case
6	U-21860	DTE Electric Company	Electric Rate Case

DIRECT TESTIMONY OF JING SHI
CASE NUMBER U-21870
PART II

1 Q. What is the purpose of your testimony?

2 A. The purpose of my testimony is to present the Staff's review and analysis of and
3 recommended adjustments to Consumers Energy Company's (CE or the
4 Company) projected Asset Performance Management (APM) expenditures within
5 the Distribution Asset Management (DistAM) program, which is primarily
6 explained by Company witness Scott McPhail.

7 Q. Are you sponsoring any exhibits?

8 A. No.

9

10 Q. Please briefly describe the DistAM program.

11 A. DistAM program focuses on lifecycle asset management rather than real-time
12 operational management of assets, as Advanced Distribution Management System
13 (ADMS) would. As Company witness McPhail stated in his testimony on page
14 50:

15 "Asset management typically requires data that is collected and visualized
16 over long-time scales. Consequently, DistAM informs decisions over the
17 medium-to-long term as opposed to ADMS's short-term operational
18 decision-making."
19

20 The Company has been developing a DistAM program since as early as 2021 and
21 has a strategy with three key workstreams:

22 Asset Repository ("AR")

23 Asset Performance Management ("APM"), and

24 Asset Investment Planning ("AIP") (now complete).

DIRECT TESTIMONY OF JING SHI
CASE NUMBER U-21870
PART II

1 The AR provides a single centralized database to store essential distribution asset
2 data, and the APM encompasses the capabilities of data capture, integration,
3 visualization and analytics tied together to improve the reliability and availability
4 of physical assets.

5 AIP is a platform that uses asset data stored within the Asset Repository and
6 health index scores within the APM to make data-driven decisions regarding
7 capital investments, maintenance costs, criticality of budgets and associated risks,
8 and analysis to plan where and when to invest over extended time horizons.

9 Q. Please explain more about the APM component.

10 A. As Company witness McPhail stated in his testimony, page 56:

11 “APM encompasses the capabilities of data capture, integration,
12 visualization, and analytics tied together to improve the reliability and
13 availability of physical assets. The APM is a software tool that leverages
14 the base of asset data made available from the AR to develop a health
15 index or a health score for assets across electric distribution. This tool will
16 use advanced algorithms to develop health and risk monitoring through a
17 standard and common interface for Company employees to generate,
18 monitor, and make decisions for identifying opportunities to address assets
19 requiring attention based on asset health and risk. It is expected that these
20 asset health and risk scores will be incorporated into the Company’s
21 Quarterly Operating Review (“QOR”).”

22
23 He continues to explain that Company data scientists will design and test the
24 necessary algorithms to produce a health score with its associated risk.

25 Q. What has the Company spent to date and what is forecasted?

26 A. As of March 31, 2025, the Company has reported \$7.9 million in total
27 investments under the DistAM program. The AIP, launched in 2024, accounted
28 for \$5.8 million of this amount and approximately \$2.1 million has been spent on
29 the AR. However, the Company has not yet spent any funds on the APM

DIRECT TESTIMONY OF JING SHI
CASE NUMBER U-21870
PART II

1 component as of March 31, 2025. Despite the lack of spending, CE had projected
2 \$1,226,000 for the bridge period and \$6,248,000 for the test year in the prior case.
3 Another round of projections of \$770,000 and \$2,640,000 for bridge and test year
4 are in the current case.

5 Q. Please summarize the Commission's decisions regarding the DistAM program.

6 A. The Order in Case No. U-21585, page 110, stated the following:

7 "The Commission agrees with the ALJ and finds that Consumers has not
8 demonstrated that the projected costs for the DistAM program are
9 reasonable and prudent. In the March 1 order, the Commission noted that
10 its original approval of the DistAM program was based on a CAD from
11 2021 which projected total costs of \$12 million through 2024. As such, the
12 Commission stated that it would require updated data, including total
13 costs, for any future recovery. See, March 1 order, p. 41. The Commission
14 finds that Consumers has not provided adequate data supporting recovery
15 of the increased costs of the DistAM program. Accordingly, the
16 Commission adopts the ALJ's recommendation and disallows \$5.558
17 million in expenditures for the program."
18

19 The Commission originally approved DistAM in Case No. U-20697 and
20 subsequently reaffirmed its approval in the December 22, 2021 Order in Case No.
21 U-20963. Thus, the program has been in place for more than three years, yet no
22 expenditure has been made on the APM to date.

23 Q. Has the Company provided adequate cost justification in the current case?

24 A. No. Consumers Energy has not provided sufficiently detailed explanations
25 regarding: 1) why previously authorized funds were not spent on APM; and 2)
26 how projected funds will be used in the bridge and test year in the current case.
27 This lack of transparency prevents Staff from validating whether the requested
28 additional expenditures are reasonable and prudent.

DIRECT TESTIMONY OF JING SHI
CASE NUMBER U-21870
PART II

1 Even if the entire \$5.558 million previously disallowed were attributable solely
2 to APM, approximately \$0.69 million would remain available for the Company
3 to spend. Yet, CE has not allocated or expended any funds on APM to date.
4

5 Q. What is Staff's recommendation regarding the Company's proposed APM
6 expenditures?

7 A. Due to the Company's failure to provide reasonable justification for unused funds
8 and demonstrate tangible progress on APM, Staff recommends that the
9 Commission disallow the full amount of APM expenditure proposed for both the
10 bridge period of \$770,000 and the test year of \$2,640,000.

11 Q. Does that conclude your testimony?

12 A. Yes.

1 MR. SONNEVELDT: Next, Your Honor, Staff moves
2 to bind in the direct testimony of Joshua Towslee. Mr.
3 Towslee's direct testimony consists of a cover sheet and
4 six pages of questions and answers. He sponsors no
5 exhibits.

6 JUDGE THOITS: Are any objection to the
7 admission of this testimony?

8 Hearing none. The direct testimony of Joshua
9 Towslee is bound into the record.

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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 the authority to increase its rates for the generation and distribution of electricity and <u>for other relief.</u>	)))))	Case No. U-21870

QUALIFICATIONS AND DIRECT TESTIMONY OF
JOSHUA S. TOWSLEE
MICHIGAN PUBLIC SERVICE COMMISSION

September 30, 2025

QUALIFICATIONS OF JOSHUA S. TOWSLEE
CASE NUMBER U-21870
PART I

1 Q. Please state your name and business address.

2 A. My name is Joshua S. Towslee (he/him/his). My business address is 7109 W.
3 Saginaw Hwy., Lansing, Michigan 48917.

4 Q. By whom are you employed and in what capacity?

5 A. I am employed by the Michigan Public Service Commission (MPSC or
6 Commission) as a Departmental Analyst in the Interconnection and Distributed
7 Energy Resources Section within the Energy Operations Division.

8 Q. Please describe your educational background.

9 A. I earned a Bachelor of Arts in Professional Communication from Siena Heights
10 University in 2019. Prior to that, I studied computer science on an engineering
11 track at Michigan State University.

12 Q. Please describe your professional background.

13 A. My employment at the MPSC began in 2017 as a Student Assistant in the
14 Strategic Operations Division. After graduating in 2019, I became a
15 Departmental Analyst in the Communications Section within the Strategic
16 Operations Division.

17 In 2021, I accepted a position as a Communications Manager at
18 Michigan State University, working jointly for the Institute for Water Research
19 and the College of Agriculture and Natural Science's Department of Fisheries and
20 Wildlife.

21 In 2022, I returned to the MPSC as a Departmental Analyst in the
22 IDER Section. My current job duties include case coordination, analysis, and
23 internal project management for demand response (DR), interconnection, and

QUALIFICATIONS OF JOSHUA S. TOWSLEE
CASE NUMBER U-21870
PART I

1 distributed generation-related matters. I am currently serving as the Case
 2 Coordinator for MPSC Staff in multiple DR reconciliation cases.

3 Q. Have you received any work-related training since starting your employment with
 4 the MPSC?

5 A. Yes. I have attended several training sessions hosted by Michigan State
 6 University's Institute of Public Utilities, including Grid School and Ratemaking
 7 Courses. I have also completed EUCI courses on Electricity and Electric Utilities.

8 Q. Have you previously testified before the Commission?

9 A. Yes, I have testified in the following cases:

<u>Case Number</u>	<u>Company</u>	<u>Case Type/Subject</u>
U-21403	DTE Electric Company	DR Reconciliation
U-21585	Consumers Energy	Electric Rate Case
U-21658	DTE Electric Company	DR Reconciliation
U-21809	Upper Peninsula Power Co.	IRP
U-21860	DTE Electric Company	Electric Rate Case
U-21906	Consumers Energy	DR Reconciliation

DIRECT TESTIMONY OF JOSHUA S. TOWSLEE
CASE NUMBER U-21870
PART II

1 Q. What is the purpose of your testimony?

2 A. The purpose of my testimony is to present the MPSC Staff's (Staff)
3 recommendations regarding Consumers Energy Company's (Consumers or the
4 Company) proposed Whole Home Optimization Demand Response pilot and the
5 Company's requested changes to the demand response regulatory construct.

6 Q. Are you sponsoring any exhibits in the proceeding?

7 A. No.

8 Q. What is the Whole Home Optimization Demand Response pilot?

9 A. The Company is proposing this pilot for the purpose of investigating customer-
10 owned smart home energy management systems, battery storage, and load
11 management devices. The Company seeks to explore how aggregation of in-home
12 resources and energy usage and demand analytics may facilitate customer-
13 controlled responses and influence load management behaviors. Consumers is
14 requesting \$750,000 in capital and \$250,000 in O&M to support this pilot.¹

15 Q. What are Staff's recommendations regarding this pilot?

16 A. Consumers states its intent to provide updates on this pilot in its future electric
17 rate cases and DR reconciliations, notify MPSC Staff and other intervenors of
18 significant changes from the approved plan during implementation or pilot design,
19 and share the results of evaluation when complete.² Staff looks forward to
20 reviewing the findings and requests that, in addition to the aforementioned
21 updates and notifications, detailed breakdowns of the following be included in

¹ Direct Testimony of Alex Gast, pp 18-19.

² Exhibit A-182, p 7.

DIRECT TESTIMONY OF JOSHUA S. TOWSLEE
CASE NUMBER U-21870
PART II

each of the Company's relevant filings during the operation of this pilot: pilot costs (both for the relevant period and cumulative), allocation of remaining funds, energy savings attributable to the pilot, and cost-effectiveness assessments. In its next rate case or DR filing, the Company should also include more information about the specific technologies being tested. The Company is planning to work with implementation contractors, third-party evaluators, and software and hardware vendors to install and test a variety of available technologies.³ While Staff believes this type of pilot can be highly educational and may result in many lessons learned and inform potential future programs, it is important to identify the technologies that will be tested. For that reason, Staff requests the Company provide more detail in the next relevant filing about the technologies the Company is planning to test in the pilot and how each technology will be evaluated. Additionally, Staff requests Consumers provide discussion of its intentions for any necessary transition or integration of the pilot participants once the pilot period concludes at the end of 2028.⁴

Q. What changes to the DR regulatory construct has Consumers requested?

A. As it did in its 2024 DR reconciliation case, MPSC Case No. U-21906, which is currently before the Commission, the Company proposes removing consideration and approval of DR capital and O&M spend from the rate case and shifting all DR matters instead to an annual DR filing. Consumers envisions this proposed annual filing would operate as both a DR plan case and a reconciliation,

³ Exhibit A-182, p 5.

⁴ Exhibit A-182, p 8.

DIRECT TESTIMONY OF JOSHUA S. TOWSLEE
CASE NUMBER U-21870
PART II

1 beginning with the 2027 planning year. Under this framework, in 2026
2 Consumers would file a DR case covering both its 2025 reconciliation and 2027
3 planned spend.⁵

4 Q. Does Staff support this suggestion?

5 A. While Staff is in favor of changes to the current DR framework, it should be noted
6 that this issue is currently under consideration in MPSC Case No. U-21637,
7 wherein the Commission seeks “to investigate opportunities for improving the
8 process by which it reviews applications filed under Section 6a.”⁶ Section 6a
9 refers to Section 6a of Public Act 3 of 1939 (MCL 460.6a), as amended, the
10 statute that governs the rate case process which the Commission was directed to
11 review by Public Act 231 of 2023. On July 10, 2025, the Commission issued an
12 Order in that case which requested additional comment on, among other things, a
13 new DR process. The deadline for those comments was September 10, 2025.⁷

14 Thus, Staff’s opinion is that the MPSC Case No. U-21637 docket is a more
15 appropriate venue for discussion of changes to the DR process, and any
16 consideration of the Company’s suggested changes to the regulatory construct
17 should be deferred pending the Commission’s decision in that case.

18 Q. Does Staff have other recommendations regarding the Company’s DR programs
19 and pilots or suggested changes to the DR framework?

20 A. Not at this time.

21 Q. Please summarize your testimony.

⁵ Direct Testimony of Alex Gast, pp 8-10.

⁶ May 23, 2024 Order in Case No. U-21637, p. 1.

⁷ July 10, 2025 Order in Case No. U-21637, p. 41.

DIRECT TESTIMONY OF JOSHUA S. TOWSLEE
CASE NUMBER U-21870
PART II

1 A. Staff requests inclusion of the following information in the Company's relevant
2 filings during the pilot period for its Whole Home Optimization Demand
3 Response pilot: pilot costs, allocation of remaining funds, energy savings,
4 technologies that will be tested and evaluated, cost-effectiveness assessments, and
5 plans for participants once the pilot period ends. Staff also recommends decisions
6 regarding changes to the DR regulatory framework be deferred to the proceedings
7 in MPSC Case No. U-21637.

8 Q. Does this conclude your testimony?

9 A. Yes.

1 MR. SONNEVELDT: Next, Your Honor, Staff moves
2 to bind in the direct testimony of Kevin Krause. Mr.
3 Krause's testimony consists of a cover sheet and five
4 pages of questions and answers. He sponsors no exhibits.

5 JUDGE THOITS: Was this just direct testimony,
6 or was there a rebuttal also?

7 MR. SONNEVELDT: Just direct testimony, Your
8 Honor.

9 JUDGE THOITS: Are there any objection to the
10 admission to this testimony?

11 Hearing none. The direct testimony of Kevin
12 Krause is bound into the record.

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STATE OF MICHIGAN
BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

Case No. U-21870

In the matter of the application of
Consumers Energy Company
for authority to increase its rates for the generation
and distribution of electricity and for other relief.

QUALIFICATIONS AND DIRECT TESTIMONY OF

KEVIN S. KRAUSE

MICHIGAN PUBLIC SERVICE COMMISSION

September 30, 2025

**QUALIFICATIONS AND DIRECT TESTIMONY OF
KEVIN S. KRAUSE
U-21870**

1 Q. Please state your name and business address.

2 A. My name is Kevin S. Krause, and my business address is 7109 W. Saginaw Highway,
3 Lansing, MI 48917.

4 Q. By whom are you employed and in what capacity?

5 A. I am employed by the Michigan Public Service Commission (Commission or MPSC) as a
6 Gas Cost of Service Specialist within the Regulated Energy Division, Rates and Tariff
7 Section.

8 Q. How long have you been employed by the MPSC and what are your duties?

9 A. I have been employed by the MPSC since February of 2009. I was assigned to the
10 Revenue Requirements Section to analyze and make recommendations regarding Rate
11 Base, Net Operating Income, and Depreciation issues in general rate cases and
12 depreciation rate cases. In August of 2012, I was transferred to the Renewable Energy
13 Section. In November of 2016, I was transferred to the Rates and Tariff Section.

14 Q. Please describe your educational background.

15 A. I graduated from the University of Michigan in 1990 with a Bachelor of Science degree
16 in Nuclear Engineering. I received a Masters of Nuclear Engineering from the same
17 school in 1991. I also received a Masters in Business Administration from Michigan
18 State University in 1999. I have taken classes as part of the Certified Public Accountant
19 preparation program at Lansing Community College. I also attended the Institute of
20 Public Utilities - Regulatory Studies Program at Michigan State University. In the fall of
21 2010, I completed the Depreciation Basics Training conducted by the Society of
22 Depreciation Professionals (SDP).

**QUALIFICATIONS AND DIRECT TESTIMONY OF
KEVIN S. KRAUSE
U-21870**

1 Q. Please describe your professional background.

2 A. From 1992 to 1997, I worked as a Nuclear Engineer for B & W Fuel Company in
3 Lynchburg, Virginia. My duties there included performing fuel cycle analysis and related
4 calculations. In 1998, I was a procurement intern with Public Service Electric and Gas
5 Company of Newark, New Jersey. From 2002 to 2010, I was an adjunct professor of
6 Mathematics at Lansing Community College.

7 Q. Have you previously presented testimony or helped develop the Commission Staff's
8 (Staff) position in cases before the MPSC?

9 A. Yes, I have filed or developed Staff's position in the following cases with area of
10 testimony specified:

<u>Case No.</u>	<u>Company</u>
11	
12	U-15768 Detroit Edison Electric - AFUDC
13	U-15935 Alpena Power - Operations and Maintenance (O&M) Expense
14	U-15985 Michigan Consolidated Gas Case - Revenue Deficiency
15	U-15986 Consumers Energy Gas Case - Rate Base
16	U-16180 Indiana Michigan Electric Case - Rate Base
17	U-16166 Upper Peninsula Power Company – O&M Expense
18	U-16169 SEMCO Energy Gas Company – O&M Expense
19	U-16417 Upper Peninsula Power Company Electric Case - Revenue Deficiency
20	U-16475 Northern States Power Company Electric Case - Revenue Deficiency
21	U-16794 Consumers Energy Electric Case - Rate Base
22	U-16801 Indiana Michigan Electric Case - Rate Base
23	U-16855 Consumers Energy Gas Case - Rate Base
24	U-17026 Indiana Michigan Certificate of Necessity – Accounting
25	U-17303 Indiana Michigan Renewable Energy Plan
26	U-17321 Consumers Energy 2012 Renewable Reconciliation
27	U-17323 Indiana Michigan 2012 Renewable Reconciliation
28	U-17429 Consumers Energy Certificate of Necessity – Accounting
29	U-17631 Consumers Energy 2013 Renewable Reconciliation
30	U-17632 DTE Electric 2013 Renewable Reconciliation - Rebuttal
31	U-17633 Indiana Michigan 2013 Renewable Reconciliation
32	U-17767 DTE Electric Rate Case – Certain Nuclear Expenses
33	U-17803 Consumers Energy 2014 Renewable Reconciliation

**QUALIFICATIONS AND DIRECT TESTIMONY OF
KEVIN S. KRAUSE
U-21870**

1	U-18014	DTE Electric Rate Case – Renewable Expenses
2	U-18090	Consumers Energy – Avoided Cost
3	U-18091	DTE Electric – Avoided Cost
4	U-18322	Consumers Energy – Standby Rates – Rebuttal
5	U-18255	DTE Electric – Standby Rates – Rebuttal
6	U-18259	Presque Isle Gas – Cost of Service and Rate Design
7	U-18424	Consumers Energy Gas Rate Case – Other Gas Revenue
8	U-18999	DTE Gas Rate Case – Other Gas Revenue and Rate Design
9	U-20106	DTE Gas – Credit A
10	U-20115	SEMCO Energy Gas Company – Credit A
11	U-20182	SEMCO Energy Gas Company – Credit B
12	U-20134	Consumers Energy Rate Case – Standby and Electric Vehicle Rates
13	U-20162	DTE Electric Rate Case – DG tariff, Standby and Electric Vehicle Rates
14	U-20276	UPPCO Electric Rate Case – Rate Design
15	U-20479	SEMCO Gas Rate Case – Cost of Service
16	U-20359	Indiana Michigan Rate Case – Demand Charge pilot and DG tariff rebuttal
17	U-20561	DTE Electric – DG tariff rebuttal
18	U-20642	DTE Gas Rate Case – Cost of Service
19	U-20650	Consumers Energy Gas Rate Case – Cost of Service
20	U-20697	Consumers Energy Electric Rate Case - DG Tariff
21	U-20940	DTE Gas Rate Case – Cost of Service
22	U-20718	MGU Gas Rate Case – Cost of Service
23	U-21090	Consumers Energy Integrated Resource Plan
24	U-21148	Consumers Energy Gas Rate Case – Cost of Service
25	U-20836	DTE Electric – DG tariff and Electric Vehicles
26	U-21226	NSP Gas Rate Case – Cost of Service
27	U-21308	Consumers Energy Gas Rate Case – Cost of Service
28	U-21366	MGU Gas Rate Case – Cost of Service
29	U-21297	DTE Electric Rate Case – Electric Vehicles
30	U-21389	Consumers Energy Electric Rate Case – Electric Vehicles
31	U-21461	Indiana Michigan Electric Rate Case – DG tariff rebuttal
32	U-21374	Consumers Electric Voluntary Green Pricing Case - rebuttal
33	U-21490	Consumers Energy Gas Rate Case – Cost of Service
34	U-21291	DTE Gas Rate Case - Cost of Service
35	U-21534	DTE Electric – Community Solar, EV, and Microgrid rebuttal
36	U-21585	CE Electric – Community Solar, EV, and Microgrid rebuttal
37	U-21816	Consumers Electric Voluntary Green Pricing Case – rebuttal
38	U-21806	Consumers Gas Rate Case – Cost of Service
39	U-21860	Consumers Electric Rate Case – EV rates
40		

41 Q. What is the purpose of your testimony?

42 A. The purpose of my testimony is to provide Staff’s recommendations on Electric Vehicle

**QUALIFICATIONS AND DIRECT TESTIMONY OF
KEVIN S. KRAUSE
U-21870**

1 (EV) tariffs and rate design and to comment on the production allocator in cost-of-
2 service.

3 Q. Are you filing any exhibits?

4 A. No.

5 Demand Charge Holiday Recommendations

6 Q. Is the Company proposing a change with respect to the demand charge holiday?

7 A. No.

8 Q. Should Rate GP be closed to fast charging customers?

9 A. Yes. GP is already closed to new customers because it does not reflect cost of service.

10 Charging stations on rate GP are receiving a subsidy and that subsidy should be

11 discontinued. Under rate GP, charging stations are treated as if increasing charging

12 speed has no incremental impact on cost causation, such as increased infrastructure. As

13 charging stations increase in speed and demand, the GP rate becomes less and less

14 appropriate. Stations on rate GP are clearly receiving a subsidy. Staff recommends that

15 rate GP should be closed to both new and existing fast charging stations on June 1, 2028.

16 This date corresponds to a similar proposal made by Staff for DTE Electric Company.

17 Q. When are the next steps related to the demand charge holiday?

18 A. Staff proposes that the Company introduce a new tariff for fast charging in its next rate

19 case based on available fast charging data. Staff further proposes that the tariff be based

20 on cost-of-service. Since there would likely be a preference for an energy only rate, with

21 no demand charges, Staff would like to see this incorporated into the proposal. Staff also

22 recommends that the utility provide rate design options considering charging station

**QUALIFICATIONS AND DIRECT TESTIMONY OF
KEVIN S. KRAUSE
U-21870**

1 uptime and charging reliability.

2 Conclusion and Recommendations

3 Q. Please summarize your recommendations.

4 A. My recommendations are as follows:

5 -Close Rate GP to new and existing charging stations on June 1, 2028.

6 -Propose a new Fast Charging Tariff in the next rate case.

7 Q. Does this conclude your testimony?

8 A. Yes.

1 MR. SONNEVELDT: Next, Your Honor, Staff moves
2 to bind in the direct testimony of Theresa McMillan
3 Sepkoski. That testimony consists of a cover sheet and
4 nine pages of questions and answers. She also sponsors
5 Exhibits S-9.1 and S-9.2.

6 JUDGE THOITS: Are there any objections to the
7 admission of this testimony or these exhibits?

8 Hearing none. The direct testimony of Theresa
9 McMillan Sepkoski is bound under the record, and Exhibits
10 S-9.1 and S-9.2 are admitted.

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STATE OF MICHIGAN
BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

Case No. U-21870

In the matter of the application of
CONSUMERS ENERGY COMPAY
for authority to increase its rates for the
generation and distribution of electricity
and for other relief.

QUALIFICATIONS AND DIRECT TESTIMONY OF

THERESA MCMILLAN-SEPKOSKI

MICHIGAN PUBLIC SERVICE COMMISSION

September 30, 2025

**QUALIFICATIONS AND DIRECT TESTIMONY OF
THERESA MCMILLAN-SEPKOSKI
U-21870**

1 Q. Please state your name and business address.

2 A. My name is Theresa L. McMillan-Sepkoski. My business address is 7109 West Saginaw
3 Hwy, Lansing MI, 48917.

4 Q. By whom are you employed and in what capacity?

5 A. I am employed by the Michigan Public Service Commission (MPSC or Commission) as
6 an Audit Specialist in the Revenue Requirements Section of the Regulated Energy
7 Division.

8 Q. What is your educational background?

9 A. I graduated in 1981 from Mott Community College with an A.A.S. degree in Accounting
10 with a minor in Business Management. In June 2006, I graduated from Baker College
11 with highest honors and a B.B.A. degree with emphasis in Accounting. Since becoming
12 employed here at the Commission, I have participated in numerous MPSC training
13 sessions and attended the National Association of Regulatory Utility Commissioners
14 (NARUC) Advanced Regulatory Studies Program.

15 Q. Please describe your professional background.

16 A. Prior to my employment at the MPSC, I worked in accounting in the public and private
17 sector for sixteen years after receiving my associate degree. I began my employment at
18 the Shiawassee County Health Department as an Accounts Processor. From there my
19 experience in accounting came from working for Federal Forge Inc., also known as
20 Bharat Forge Ltd. from an entry level position in Accounts Payable and promoted to
21 Controller. After that I worked for CSI Inc. as an Assistant Controller/Human Resource
22 Administrator. In December 2006, having completed my bachelor's degree, I began my

**QUALIFICATIONS AND DIRECT TESTIMONY OF
THERESA MCMILLAN-SEPKOSKI
U-21870**

1 employment with the Michigan Public Service Commission and have continued through
2 the present.

3 Q. Briefly discuss your experience with the MPSC.

4 A. I have served as the lead auditor, case coordinator, and performed audit work in many
5 types of cases for the MPSC. The types of cases have been gas and electric rate cases,
6 Power Supply Cost Recovery (PSCR) and Gas Cost Recovery (GCR) reconciliation
7 cases, Cooperative Times Interest Earned Ratio (TIER) review cases, and various
8 tracking mechanism cases. I have also testified before the Commission on previous
9 Revenue Requirement rate cases.

10 Q. Have you previously filed testimony before the MPSC?

11 A. Yes, I have filed testimony in the following cases:

12 U-15190 – Consumers Energy Company Gas Rate Case
13 U-15244 – Detroit Edison Company Electric Rate Case
14 U-15245 – Consumers Energy Company Electric Rate Case
15 U-15506 – Consumers Energy Company Gas Rate Case
16 U-16034-R – Wisconsin Electric Power Co. 2010 PSCR Reconciliation
17 U-16149-R – Consumers Energy Co. 4/10 – 3/11 GCR Reconciliation
18 U-16424-R – Wisconsin Electric Power Co. 2011 PSCR Reconciliation
19 U-17095-R – Consumers Energy Co. 2013 PSCR Reconciliation
20 U-17130-R – Michigan Gas Utilities Corporation 4/13 - 3/14 GCR Reconciliation
21 U-17133-R – Consumers Energy Co. 4/13 – 3/14 GCR Reconciliation
22 U-17317-R – Consumers Energy Co. 2014 PSCR Reconciliation
23 U-17334-R – Consumers Energy Co. 4/14 – 3/15 GCR Reconciliation
24 U-17691-R – DTE Gas 4/15 – 3/16 GCR Reconciliation
25 U-18124 – Consumers Energy Co. Gas Rate Case
26 U-18250 – Consumers Energy Co. Securitization Case
27 U-20134 – Consumers Energy Co. Electric Rate Case
28 U-20162 – DTE Electric Rate Case
29 U-20276 – Upper Peninsula Power Co. Electric Rate Case
30 U-20322 – Consumers Energy Gas Rate Case
31 U-20479 – SEMCo Energy Gas Co. Gas Rate Case
32 U-20561 – DTE Electric Rate Case
33 U-20642 – DTE Gas Rate Case

**QUALIFICATIONS AND DIRECT TESTIMONY OF
THERESA MCMILLAN-SEPKOSKI
U-21870**

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
 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
 U-21806 – Consumers Gas Rate Case
 U-21860 – DTE 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)), the 15-year amortization of cloud implementation costs for the Software as a Service (SaaS), and the Extraordinary Storm Accounting request for deferred accounting treatment of service restoration costs for the test year ending April 30, 2027.

Q. Are you sponsoring any exhibits in this proceeding?

A. Yes, I am sponsoring the following exhibits:

Exhibit Title

S-9.1 Company Response U21870-SA-CE-001

**QUALIFICATIONS AND DIRECT TESTIMONY OF
THERESA MCMILLAN-SEPKOSKI
U-21870**

1 S-9.2 Company Response U21876-SA-CE-003

2

3 **Employee Incentive Compensation Plan (EICP) Expense**

4 Q. What is EICP expense?

5 A. EICP expense is a portion of an employee's pay that is dependent upon achieving
6 target levels on performance measures.

7 Q. Has Consumers Energy requested recovery of EICP expense in this case?

8 A. Yes. The Company has included \$2,211,000 for EICP expense in the revenue
9 requirement per Company witness Amy M. Conrad's testimony, page 32, line
10 8, and Company Exhibit A-73 (AMC-3), page 1 of 2.

11 Q. What are the performance measures of the Company's EICP?

12 A. Company Exhibit A-71 (AMC-1) page 1 of 4 outlines the employee performance
13 measures. The measures are categorized as operational measures. There are six
14 operational performance measures.

15 Q. How do employees earn the incentive compensation?

16 A. Employees earn EICP by achieving target levels in each performance measure.
17 Examples of target levels found on Exhibit A-71 (AMC-1) page 2 of 4 are
18 achieving less than or equal to 170 for the Electric Reliability (System
19 Average Interruption Duration Index) and a Customer Experience Index of greater
20 than or equal to 69, achieved at target level to earn 100% of the proposed EICP
21 expense requested for recovery in this case. Per Company Witness Conrad, the
22 Company has discontinued determining target levels at absolute goal achievement

**QUALIFICATIONS AND DIRECT TESTIMONY OF
THERESA MCMILLAN-SEPKOSKI
U-21870**

1 to individual banded goals that provide each measure with its own threshold,
2 target, and maximum performance goal for achieving a certain level of payout.

3 Q. Describe the changes the Company has made to its request for inclusion of the
4 EICP expense in rates.

5 A. First, the Company has excluded the costs for short-term incentive compensation
6 related to financial measures. Secondly, it has included the costs of the short-term
7 incentive compensation based on operational measures for the top five (5)
8 officers in the revenue requirement. Prior to Consumers Energy electric rate case,
9 Case No. U-21224, the Company had not included incentive compensation costs
10 for the top five (5) officers.

11 Q. Does Staff support the Company's request for EICP expense based on operational
12 measures in rates?

13 A. Staff supports the request for operational measures EICP expenses for non-union
14 Employees in the amount of \$2,018,400, but not for the EICP expenses for the
15 top five officers that have been included in the current case. The costs for the
16 EICP incentive compensation for the top five officers for the projected test year
17 are \$192,600. (see Staff Exhibit S-9.1)

18 Q. Please explain why Staff does not recommend the top five officers EICP expense
19 being approved.

20 A. Staff has two points for not recommending including the top five officers
21 incentive compensation. First, in Company witness Amy M. Conrad's testimony,
22 pages 10-24, she discusses Consumers compensation philosophy. Employees'

**QUALIFICATIONS AND DIRECT TESTIMONY OF
THERESA MCMILLAN-SEPKOSKI
U-21870**

1 salaries should be comparable to the market median, within a target level plus or
2 minus 5% of the market median, giving examples of Consumer's pay levels
3 compared to market levels. On page 22, lines 9 - 13, officer compensation
4 packages are targeted at the median or 50th percentile of the market.
5 Staff asked for the compensation level of the top five officers compared to market
6 median. The Company declined to provide this information to Staff (see Staff
7 Exhibit S-9.2, page 1 of 2) through audit responses. Second, the Company instead
8 offered for Staff to examine report extracts of the Pay Governance report, with conditions
9 attached:

- 10 -Reviewed in the presence of an appropriate CMS representative
11 -Maintain the confidentiality of the extracts
12 -May not copy or distribute the extracts to any other party
13 -Used only for the sole purpose of this inquiry
14 -Exempt Pay Governance from any public disclosure/Freedom of Information request or
15 open records acts (See Exhibit S-9.2, page 2 of 2).

16 Q. Did the Company offer access to the report extracts to Staff?

17 A. Yes. Staff has previously gone to the Company's satellite office and viewed the report
18 extracts provided prior to filing testimony in Consumers Gas rate case U-21806.

19 Q. What did Staff recommend after viewing these reports?

20 A. Staff recommended disallowance of the operational measures portion of EICP for the top
21 5 officers in case No. U-21806. Staff appreciated the Company taking the time and
22 providing the report extracts, but the reports were anonymous to each executive and only

**QUALIFICATIONS AND DIRECT TESTIMONY OF
THERESA MCMILLAN-SEPKOSKI
U-21870**

1 presented how Pay Governance calculates the market data. There was no financial
2 presentation of the compensation data that Staff needed to examine to make a valid
3 comparison.

4 Q. Did Staff examine the report extracts in the current case when offered by the Company to
5 view them?

6 A. No Staff did not. These report extracts would most likely be the same as before and Staff
7 felt that until the Company can disclose the information that Staff needs to make a proper
8 assessment, the usefulness of the reports is negligible.

9 **Amortization of Cloud Implementation Costs for SaaS**

10 Q. Please explain the Cloud Implementation costs for SaaS.

11 A. These costs are part of the SAP S/4HANA implementation project.

12 Q. What is the Company requesting in the current rate case?

13 A. The Company is requesting approval for a 15-year amortization of these costs so that the
14 costs are spread over a longer period of time to minimize the impact on customer rates.

15 Q. Does Staff approve the Company's request for the 15-year amortization of the Cloud
16 Implementation costs for SaaS?

17 A. Yes, Staff recommends approval of the 15-year amortization of these costs. Please refer
18 to Staff Witness Zichi's testimony for further recommendations regarding the SAP
19 S/4HANA upgrade.

20 **Extraordinary Storm Accounting (ESA)**

21 Q. Please explain the Extraordinary Storm Accounting the Company has requested in this
22 case.

**QUALIFICATIONS AND DIRECT TESTIMONY OF
THERESA MCMILLAN-SEPKOSKI
U-21870**

1 A. The Company is requesting to use deferred accounting to defer the costs of extraordinary
2 storms. The Company wants the ability to automatically defer the costs without having
3 to file a case with the Commission when this happens. The deferral would happen when
4 at least 300,000 customer outages over a seven-day period or when the Governor's office
5 declares a state of emergency. This request to use deferred accounting would be activated
6 when the Company has extraordinary storm costs that exceed approved base spending
7 levels.

8 Q. How would the Company account for these deferred costs?

9 A. The Company would seek approval of the deferral costs from the Commission in a future
10 rate case.

11 Q. Does Staff agree with approving automatic deferral accounting for extraordinary storms
12 costs?

13 A. No, Staff does not agree for two reasons.

14 Q. Please explain why Staff does not agree with approval of the ESA the Company is
15 requesting.

16 A. First, after the extraordinary storm in March/April of 2025 in northern Michigan, the
17 Company filed an *ex parte* case with the Commission, Case No. U-21914. This case was
18 a request for approval of accounting authority to defer the operations and maintenance
19 costs using a regulatory asset. This case was filed on April 23, 2025, and the
20 Commission approved this action with stipulations in its Order dated June 12, 2025.
21 The Commission Order for the utilization of deferred accounting in Case No. U-21914
22 had rendered the final ruling merely seven (7) weeks, just Thirty-Seven (37) business

**QUALIFICATIONS AND DIRECT TESTIMONY OF
THERESA MCMILLAN-SEPKOSKI
U-21870**

1 days after the Company had filed, and Staff believes this is a reasonable amount of time
2 for the Company to request and receive approval from the Commission to defer any
3 extraordinary storm costs.

4 Second, there is no dollar amount tied to this request for deferral accounting. It is a “just
5 in case” scenario. Staff does not believe that this would be best practices for the ALJ or
6 the Commission to approve an open-ended request when there are other avenues that the
7 Company can utilize.

8 Q. Please summarize Staff’s recommendations in the current case.

9 A. Staff recommends disallowance of \$192,600 incentive compensation for the top 5
10 officers, disapproval of the request for Extraordinary Storm Accounting deferred
11 accounting treatment for future service restoration costs, and approval of the request for
12 15-year amortization of the Cloud Implementation costs for SaaS.

13 Q. Does this conclude your testimony?

14 A. Yes, it does.

1 MR. SONNEVELDT: Next, Your Honor, Staff moves
2 to Biden the direct testimony of Kirk D. Megginson. Mr.
3 Megginson's direct testimony consists of a cover sheet and
4 38 pages of questions and answers. He also sponsors
5 Exhibit S-4, Schedules D-1 through D-6.

6 JUDGE THOITS: Are there any objections to the
7 admission of this testimony or this exhibit?

8 Hearing none. The direct testimony of Kirk
9 Megginson is bound in the record, and Exhibit S-4,
10 Schedules D-1 through D-6 are admitted.

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STATE OF MICHIGAN
BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

Case No. U-21870

In the matter of the application of
CONSUMERS ENERGY COMPANY
for authority to increase its rates for the
generation and distribution of electricity and for other relief.

QUALIFICATIONS AND DIRECT TESTIMONY OF

KIRK D. MEGGINSON

MICHIGAN PUBLIC SERVICE COMMISSION

September 30, 2025

**QUALIFICATIONS AND DIRECT TESTIMONY OF
KIRK D. MEGGINSON
U-21870**

1 Q. Please state your name, business address and occupation.

2 A. My name is Kirk D. Megginson and my business address is 7109 West Saginaw
3 Highway, Lansing, MI 48917. I am employed by the Michigan Public Service
4 Commission (MPSC or Commission) as a Financial Specialist in the Revenue
5 Requirements Section of the Regulated Energy Division.

6 Q. Please describe your educational and professional background.

7 A. I graduated with a Bachelor of Science degree in Mechanical Engineering from Michigan
8 State University in March 1991 and received my Master of Business Administration
9 degree with a concentration in Finance from Clark Atlanta University in May 2002.
10 From 1991 to 2000, I worked for the Michigan Consolidated Gas Company as an account
11 manager, primarily responsible for managing the natural gas transportation accounts of
12 industrial and commercial clients in Wayne and Washtenaw counties.
13 In December 2002, I began work as a Financial Analyst at the MPSC. As a Financial
14 Analyst, I analyzed and reported on the financial statistics of regulated Michigan
15 jurisdictional utility companies and assisted the MPSC Revenue Requirements section in
16 utility rate case hearings. In October 2008, I transitioned to a Financial Specialist and
17 currently provide Staff with expert testimony on capital structure development, debt and
18 equity costing, business and credit risk analysis, and other finance-related issues in rate
19 case proceedings.

20 Q. Have you received ongoing training since joining the MPSC?

21 A. Yes. In addition to my academic training, I have attended several seminars and
22 workshops on electric and gas utility financial analysis, credit risk and rating analysis and

**QUALIFICATIONS AND DIRECT TESTIMONY OF
KIRK D. MEGGINSON
U-21870**

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:

<u>Case Number</u>	<u>Company Name</u>	<u>Description</u>
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
U-16794	Consumers Energy (Electric Div.)	ROE Recommendation
U-17197	Consumers Energy (Gas Div.)	Cost of Capital (case withdrawn)
U-17643	Consumers Energy (Gas Div.)	Capital Structure/Cost of Capital
U-17735	Consumers Energy (Electric Div.)	Capital Structure/Cost of Capital
U-17880	Michigan Gas Utilities	Capital Structure/Cost of Capital
U-17882	Consumers Energy (Gas Div.)	Capital Structure/Cost of Capital
U-17895	Upper Peninsula Power Co.	Capital Structure/Cost of Capital
U-17990	Consumers Energy (Electric Div.)	Capital Structure/Cost of Capital
U-17999	DTE Energy (Gas Div.)	Capital Structure/Cost of Capital
U-18014	DTE Energy (Electric Div.)	Capital Structure/Cost of Capital
U-18124	Consumers Energy (Gas Div.)	Capital Structure/Cost of Capital

**QUALIFICATIONS AND DIRECT TESTIMONY OF
KIRK D. MEGGINSON
U-21870**

1	U-18370	Indiana-Michigan Power Co.	Capital Structure/Cost of Capital
2	U-18255	DTE Electric	Capital Structure/Cost of Capital
3	U-18424	Consumers Energy (Gas Div.)	Capital Structure/Cost of Capital
4	U-18999	DTE Gas	Capital Structure/Cost of Capital
5	U-20134	Consumers Energy (Electric Div.)	Capital Structure/Cost of Capital
6	U-20322	Consumers Energy (Gas Div.)	Capital Structure/Cost of Capital
7	U-20561	DTE Electric	Cost of Capital
8	U-20650	Consumers Energy (Gas Div.)	Capital Structure/Cost of Capital
9	U-20697	Consumers Energy (Electric Div.)	Capital Structure/Cost of Capital
10	U-20963	Consumers Energy (Electric Div.)	Capital Structure/Cost of Capital
11	U-21148	Consumers Energy (Gas Div.)	Capital Structure/Cost of Capital
12	U-21224	Consumers Energy (Electric Div.)	Capital Structure/Cost of Capital
13	U-21286	Upper Peninsula Power Co.	Capital Structure/Cost of Capital
14	U-21308	Consumers Energy (Gas Div.)	Capital Structure/Cost of Capital
15	U-21389	Consumers Energy (Electric Div.)	Capital Structure/Cost of Capital
16	U-21490	Consumers Energy (Gas Div.)	Capital Structure/Cost of Capital
17	U-21585	Consumers Energy (Electric Div.)	Capital Structure/Cost of Capital
18	U-21806	Consumers Energy (Gas Div.)	Capital Structure/Cost of Capital

19
20 Q. What is the purpose of your testimony in this proceeding?

21 A. The purpose of my testimony is to provide a recommendation on behalf of the Michigan
22 Public Service Commission Staff (Staff) regarding the recommended capital structure,
23 return on common equity (ROE) and overall rate of return that Consumers Energy
24 Company (Consumers Energy, Consumers, CE-Electric or the Company) should be
25 allowed to earn on its Michigan jurisdictional electric utility investment. The
26 recommendations provided in this testimony are based on a large degree of professional
27 judgment and technical expertise in the area of financial analysis.

28 Q. Are you supporting any exhibits on behalf of Staff in this proceeding?

29 A. Yes. I am supporting Staff Exhibit S-4; Schedules D-1 through D-6:

30	<u>Schedule</u>	<u>Page</u>	<u>Title</u>
31	D-1	1	Recommended Test Year Overall Rate of Return
32	D-1 Alternative	1	Alternative Test Year Overall Rate of Return
33	D-2	1	Long-Term Debt Balance and Cost Rate

**QUALIFICATIONS AND DIRECT TESTIMONY OF
KIRK D. MEGGINSON
U-21870**

1	D-2	Alternative 1	Alternative Long-Term Debt Balance and Cost Rate
2	D-3	1	Short-Term Debt Balance and Cost Rate
3	D-4	1	Preferred Stock Balance and Cost Rate
4	D-5	1	Projected Common Equity Balance
5	D-5	2	Electric Utility Proxy Group Corporate Statistics
6	D-5	3	Proxy Group Credit Rating's Criteria
7	D-5	4	Proxy Group Return on Common Equity
8	D-5	5	Discounted Cash Flow Model (DCF) Analysis
9	D-5	6	SBBI Historical Market Risk Premium Development
10	D-5	7	Historical Capital Asset Pricing Model (CAPM) Analysis
11	D-5	8	Projected CAPM – Damodaran Trailing 12-mth MRP Analysis
12	D-5	9	Projected CAPM – Damodaran 10-year (smoothed) MRP Analysis
13	D-5	10	Dow Jones Utility Average Year 2000 - 2024
14	D-5	11	Electric Utility Historical Market Return & Bond Yield
15	D-5	12	Bond Yield + Risk Premium Model Analysis
16	D-5	13	Other State Commission ROE Decisions 2021- June 2025
17	D-5	14	Cost of Equity Range and ROE Recommendation
18	D-6	1	CE – Reg. Assets audit response from U-21148
19	D-6	2	CE-Tracking Mechanism audit response

20

21 Q. Was the proposed Exhibit S-4 prepared by you and/or under your direction?

22 A. Yes, it was.

23 Q. Please summarize Staff's capital structure and ROE recommendation.

24 A. Staff recommends a capital structure with a permanent equity to debt layer of 50% and a
 25 return on equity of 9.75%. Staff's recommended ROE is the midpoint of its 9.25% -
 26 10.25% ROE range. To aid in the determination of a fair ROE for the Company, and
 27 since CE-Electric is not publicly traded, a group of eight publicly traded electric and/or
 28 gas-electric utility companies were used as a comparable proxy to the Company. The
 29 proxy group's data was used in the traditional Discounted Cash Flow (DCF) and Capital
 30 Asset Pricing Model (CAPM) return on equity estimates. In addition to those traditional
 31 models, a Bond Yield + Risk Premium analysis and a review of electric ROE
 32 authorizations from other state jurisdictions from 2021- June 2025 was also used in this

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1 case. The Staff's 9.75% ROE recommendation considers Consumers Energy Electric
2 Division's currently authorized 9.90% ROE and the Company's 10.25% ROE request as
3 outlined in its application.

4 Q. How is your testimony structured?

5 A. My testimony is structured in two parts. Part I corresponds to my Exhibit S-4, Schedules
6 D-1 through D-4 exhibits, which describe all of the ratemaking capital structure
7 components and their cost rates other than common equity. Part I also includes a review
8 of the Company's credit rating, credit analysis and regulatory environment. Part II
9 describes my recommended common equity balance and cost of equity analysis and
10 recommendation and corresponds with my Schedule D-5 exhibits. Part II also includes
11 my review and comments on the Company's ROE analysis.

12 Q. Please start by outlining Consumers Energy's current credit rating.

13 A. Most of Consumers Energy's long-term debt is in the form of first mortgage bonds that
14 the rating agencies label as senior secured debt. This is the first rating shown on the
15 Company's Exhibit A-27, page 1 of 1 provided by witness Marc Bleckman. Standard &
16 Poor's (S&P) rates Consumers Energy's senior secured debt "A", which was raised from
17 "A-" on December 4, 2014. Moody's rates Consumers senior secured debt "A1", which
18 was lowered from "Aa3" in May 2021. Fitch rates Consumers senior secured debt "A+",
19 which was raised two notches from "A-" in March 2016.

20 Q. Have the rating agencies held the Company's credit rating stable over the years?

21 A. Yes. As noted earlier, S&P has held the Company's credit rating steady for
22 approximately 10 years and Fitch has held it steady for over eight years. Moody's one

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1 notch downward revision from Aa3 (equivalent to S&P's AA- rating) in 2021 put the
2 Company's credit rating more in line with the other two agencies ratings. The prior
3 Moody's rating appeared to be an outlier.

4 Q. Please outline some of the recent ratings agency comments on Consumers credit rating
5 and corporate outlook.

6 A. In S&P's August 2024 report, the agency stated "We believe Michigan's regulatory
7 construct as above average compared to peers because of the benefit of a streamlined 10-
8 month rate case process. Other constructive rate mechanisms include the use of forward
9 test-years, power supply cost rider adjustments, and natural gas cost rider adjustments.
10 These mechanisms help the company earn its allowed ROE and minimize regulatory lag.
11 The stable rating outlook on Consumers reflects our expectation that management will
12 focus on its core utility operations and reach constructive regulatory outcomes to avoid
13 increasing business risk"¹ In Moody's May 29, 2025, ratings report, the agency remarked
14 "Consumers Energy is regulated in Michigan by the MPSC and we view the regulatory
15 framework in Michigan to be more credit supportive than most other states. As a result of
16 the 2008 and 2016 energy legislation in Michigan, the regulatory framework has been
17 streamlined, improving both the rate case process and the timeliness of cost recovery.
18 The stable outlook reflects our expectation that financial metrics will remain stable, and
19 that Consumers Energy will continue to benefit from a consistent and generally credit
20 supportive regulatory environment."² Fitch's May 30, 2025 credit assessment noted

¹ S&P Global – Ratings Direct (Aug. 20, 2024)

² Moody's Investor Services – Credit Opinion (29, May 2025)

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1 “Fitch believes the (regulatory) framework remains constructive from a credit
2 perspective, allowing for full pass-through of fuel costs and purchased power, forward-
3 looking test years and a timely 10-month rate case resolution.”³ Thus, the credit rating
4 agencies acknowledge that Consumers currently has a stable foundation for its credit
5 rating, and that Michigan has a very equitable regulatory environment that is supportive
6 of a utility’s ongoing business and financial health.

7 Q. Have other entities commented on the regulatory environment here in Michigan?

8 A. Yes. According to S&P’s Regulatory Research Associates (RRA), the Michigan
9 commission is rated Average/1, which is in the upper tier of the national average, in terms
10 of utility credit supportive regulation. Only eight other commissions share Michigan’s
11 supportive rating. Michigan’s regulation was recently reduced from Above Average/3 to
12 Average/1 in July 2024. RRA noted that Michigan regulation remains more constructive
13 than average from an investor point of view, but outcomes of certain recent rate case
14 proceedings indicated a potential tightening in the regulatory climate.⁴ The Commission
15 has been rated in the top tier for a number of years now and the Commission has
16 proactively considered the health and welfare of Consumers Energy and the other
17 regulated utilities here in Michigan through its many orders. To that end, the Company
18 has had steady earnings over the years and earnings have generally grown in the past few
19 years. Staff asked Consumers in an audit request to provide its net income from 2010 to
20 most recent and the percent that the net income either rose or fell from the previous year.

³ Fitch Ratings-Consumers Energy Company (30-May-2025)

⁴ S&P Global – RRA State Regulatory Evaluations - Energy and RRA State Commission Profiles (July 2025) & (7/31/2024)

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The Company responded by providing the following chart.

	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 not only risen over the years but has risen rather substantially. The Company has experienced 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-28, which outlines recent country-wide utility debt issuances, Consumers issued \$700 million of secured debt in July 2024 at a very favorable rate and credit spread. This shows 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. The Company anticipates around \$2.5 billion in long-term debt issuance in this case alone, which does not suggest an inability or

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1 unwillingness to borrow. To that end, Staff's 9.75% ROE recommendation represents a
2 fair if not favorable return for the Company.

3 Q. Does Consumers Energy have regulatory policies or provisions in place that can impact
4 its credit rating?

5 A. Yes, in a positive manner. Staff asked the Company in an audit request what capital
6 tracking and cost recovery mechanisms the Company currently has in place and if they
7 are requesting new mechanisms in this case. Consumers responded that they currently
8 have the standard power supply cost recovery mechanism in place, as well as an Energy
9 Waste and a Renewable Energy mechanism in place. The Company can also recover
10 certain distribution spending through its investment recovery mechanism (IRM) with
11 surcharge authority. With respect to the IRM, the Company is requesting to increase the
12 capacity and provisions within the approved IRM, with a total request of over \$350
13 million.⁵ If approved, this will further insulate the Company from financial risk. The
14 Company has also requested additional storm damage and service restoration provisions,
15 designed to provide direct funding and preferable accounting for future exceptional
16 weather events. These programs also have the benefit of improving the Company's cash
17 flow and minimizing the Company's financial risk. This risk reduction should entail a
18 modest reduction in the Company's required ROE.

19 Q. The Company stresses the importance of certain credit metrics, namely its funds from
20 operations to debt ratio (FFO-to-Debt) metric. How have the rating agencies assessed
21 this metric for Consumers in their most recent credit opinions?

⁵ See Staff Exhibit S-4, Schedule D-6, p 2 of 2.

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1 A. S&P, in its most recent August 2024 ratings snapshot, noted “We expect CE will maintain
2 stand-alone financial measures consistent with the middle of the range for its financial
3 risk profile category, specifically FFO to debt of about 17%-19%.” S&P notes that its
4 rating could be negatively impacted if Consumers FFO-to-Debt ratio fell consistently
5 below 15%. However, S&P anticipates above threshold FFO-to-Debt ratios for
6 Consumers in the foreseeable future.

7 Moody’s, in its May 2025 rating’s report, noted “We expect the utility to maintain
8 a relatively stable financial profile with cash flow from operations before changes in
9 working capital, its CFO pre-WC to debt (Moody’s FFO-to-Debt term) averaging around
10 19 -21% over the next 2-3 years.” Moody’s also notes that Consumers rating is
11 influenced and impacted by the parent company’s significant debt profile. However,
12 Moody’s notes that the parents’ percentage of debt had reduced notably in recent years,
13 lessening the effect on Consumers rating. Moody’s also noted that if Michigan’s
14 regulatory framework became more formulaic, transparent and timely, with its suite of
15 cost recovery mechanisms for Consumers, then a ratings upgrade was possible.

16 Fitch, in its May 2025 credit opinion, noted that “Fitch forecasts Consumers
17 Energy’s funds from operations (FFO) leverage to average at its 4.5x threshold in the near
18 term and then improve to 4.2x through 2029. (Fitch notes that FFO leverage that exceeds
19 4.5x on a sustained basis, could lead to a negative ratings action.) Thus, Fitch does not
20 forecast any rating decline concern with Consumers in the immediate future.

21 From the outlook of the current ratings agency reports, the agencies don’t foresee
22 any major deterioration or long-lasting decline in the FFO-to-Debt ratio for Consumers

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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 not be given any weight 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	13,465,000	13,682,687
Preferred Stock	37,315	37,315
Common Equity	13,916,000	13,720,211
Short-Term Debt	148,300	148,300
Deferred Federal Income Tax	4,692,000	4,692,000
Job Development Investment Tax Credits	148,000	148,000

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 modification. I modified the Company's capital

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1 structure by \$435 million to balance the Company's capital structure to the 50/50 level
2 that Staff recommends. To that end, I added \$217.6 million to the long-term debt
3 balance, modifying it from \$13,465 million to \$13,683 million. The result is a LT-debt
4 balance of 49.86% of the permanent capital structure.

5 Q. Please explain how you derived your recommended common equity balance.

6 A. I adopted the Company's common equity balance through April 2027 of \$13,916 million.
7 I then modified the Company's equity balance to apply Staff's 50/50 capital structure
8 request and reduced the Company's equity balance by \$180 million. This resulted in a
9 common equity balance of \$13,720 million and a ratemaking equity ratio of 50.0%.

10 Q. Why did you modify the Company's long-term debt and common equity balances?

11 A. Primarily to abide by the Commission's repeated directives over the years for the
12 Company to move its ratemaking capital structure from an equity layer well over 50%, to
13 an equity layer equivalent with its LT-debt layer unless extraordinary circumstances
14 prevent that from occurring. For example, in the Company's recent electric rate order in
15 Case No. U-21585, the Commission stated:

16 'The Commission further agrees...the company has not
17 demonstrated significant changes in the economic circumstances to
18 support a deviation from a balanced capital structure. The Commission
19 finds that a balanced capital structure most appropriately balances the
20 interests of the utility's investors and customers, consistent with the
21 holdings in *Bluefield* and *Hope*. As such, the Commission adopts a
22 balanced capital structure of 50% debt to 50% equity utilizing the

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1 Attorney General's methodology.'⁶

2 Even more directly, the Commission stated in its July 2017 Order in Consumers Energy's
3 Case. No. U-18124 that:

4 '(The Commission) disagrees with Consumers that its proposed
5 capital structure is sufficiently balanced to avoid scrutiny. The
6 Commission cannot overemphasize the company's responsibility to
7 rebalance its equity and debt capital.'⁷

8 Those orders highlight the Commission's concern with the Company's ratemaking capital
9 structure and the desire for it to be balanced, unless circumstances prevent that from
10 happening. There are no current circumstances anticipated for the Company to deviate
11 from a balanced capital structure. In that vein, Staff's 50/50 capital structure
12 recommendation in this case fully supports the Commission's most recent authorization
13 for Consumers and its objective of equilibrium that is less costly to ratepayers and yet
14 still reasonable for the Company to maintain its wide access to capital markets.

15 Q. Have other intervenors recommended a balanced capital structure for Consumers in
16 previous rate cases?

17 A. Yes. The Attorney General (AG) has recommended a 50/50 capital structure for
18 Consumers Energy in the last electric case and in previous rate cases. The Association of
19 Businesses Advocating Tariff Equity (ABATE) has also advocated for a 50% ratemaking
20 equity level in the last case and in previous rate cases. Thus, several intervenors

⁶ MPSC Case No. U-21585, 3/21/2025 Order, p 232-233

⁷ MPSC Case No. U-18124, 7/31/2017 Order, p 45- 46.

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understand the importance of an evenly balanced capital structure that is fairer to ratepayers yet still suitable for the Company to accommodate its needs.

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 2024, the Company's average long-term debt cost was 4.10%.⁸ Thus, for every dollar of debt in the capital structure, it cost ratepayers approximately 4.1 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:

$$\text{Pre-Tax ROE} = \text{ROE} / (1 - \text{Tax Rate})$$

	<u>Pre-Tax Reform</u>	<u>Post-Tax Reform</u>
Authorized ROE	9.90%	9.90%
Tax Rate	35.0%	21.0%
Pre-Tax ROE	<u>15.23%</u>	<u>12.53%</u>

Hence, prior to tax reform, for every dollar of common equity added to the capital structure, it cost ratepayers 15.2 cents or about 3.7x the Company's cost of debt of 4.1 cents. Post tax reform, it cost ratepayers 12.5 cents for every dollar added of common equity, or 3.0x the cost of debt. Therefore, equity is clearly costlier to ratepayers than debt and the need to balance both items is as important today as it has been in past rate cases. Especially 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

⁸ Cost of LT-Debt for Historical Year ended December 31, 2024. Exhibit No. A-4 (PDD-24), Sched. D-2.

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50% equity ratio recommendation establishes that sensible objective of equilibrium and lessens the cost burden on stressed ratepayers.

Q. What is the monetary impact of a 50.75% equity layer compared to a 50.0% equity layer?

A. According to data provided by the Company, for a quarter percent change in the equity layer, it costs approximately \$3.00 million per 0.25% change.⁹ So, an approved equity layer of 50%, instead of 50.75%, will save ratepayers about \$9.0 million annually.

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 \$(000)	Company	Staff
Long-Term Debt	4.54%	4.45%*
Preferred Stock	4.50%	4.50%
Common Equity	10.25%	9.75%
Short-Term Debt	4.92%	4.92%
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 does not dispute 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 projected new debt issuances in 2025 and 2026. The Company projected May and August 2025 debt issuances of \$1.125 billion, and May and August 2026 debt issuances of \$1.325 billion. The Company provided a cost rate for the May

⁹Consumers Energy audit response to Staff – Audit Response #131

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1 and August 2025 debt issuances at 6.24% and for the May and August 2026 debt issuance
2 at a cost rate of 6.27%. I estimated a lower cost rate of 5.75% for the 2025 debt issuances
3 and 5.58% for the 2026 debt issuances. I used 30-year bond yield forecasts from S&P
4 Global Market, and the average 30-year bond yield forecasts provided by
5 Econforecasting.com. Those changes, including Staff agreeing to the other LT-Debt cost
6 rates estimated by the Company and a reasonable credit spread of 100 basis points per
7 issuance, provide for a Staff recommended overall LT-Debt cost rate of 4.45%. However,
8 Staff put an asterisk next to this cost rate based on updated information that Staff will
9 explain below. Nonetheless, this cost rate is 9 basis points less than the Company's cost
10 rate of 4.54% and would save ratepayers thousands annually. My LT-Debt analysis is
11 shown in Staff Exhibit No. S-4, Schedule D-2.

12 Q. Why did Staff put an asterick by its LT-Debt cost rate and provide an alternative Schedule
13 D-2?

14 A. In Staff's current revenue deficiency calculation, Staff included its projected overall long-
15 term debt cost rate of 4.45%. The 4.45% LT-Debt cost rate was based in part on my cost
16 rate projection of the Company's \$1.125 billion debt issuances in May & August 2025. I
17 projected a cost rate of 5.75% for the new 2025 debt issuances. However, based on
18 recent information provided by Consumers Energy in a discovery response to the
19 Attorney General, the Company noted that it issued \$1.125 billion in long-term debt in
20 May 2025 at an average cost rate of 4.77%. I provided the Company's updated cost rate
21 in my alternative Schedule D-2. The alternative Schedule D-2 indicates an overall LT-
22 Debt cost rate of 4.37%, which is 8 basis points lower than Staff's 4.45% determination

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1 and 17 basis points lower than the Company's excessive 4.54% rate. In its brief, Staff
2 plans to integrate its updated cost rate data into its revenue deficiency calculation. The
3 Commission should adopt Staff's updated LT-Debt cost rate of 4.37%. The updated LT-
4 Debt cost rate prompted Staff to also provide an alternative Schedule D-1, which
5 incorporates the updated data into its overall cost of capital calculation.

6 Q. Please explain the difference in Staff's and the Company's return on equity.

7 A. Staff provides a thorough discussion of its return on equity analysis and recommendation
8 and the difference between Staff's and the Company's cost of equity determination in the
9 return on equity analysis below.

10 Q. Before discussing the recommended return on equity, does Staff have concerns with the
11 Company's excessive ST-debt facilities and its unreasonable cost to ratepayers?

12 A. Yes. Staff believes the Company's excessive ST-debt facilities, at well over \$1.0 billion,
13 is inefficiently used and costly to ratepayers. Specifically, Staff requests that the
14 Commission disallow the costs associated with the Company's Scotiabank Revolver to be
15 included in the Company's ST-debt cost rate in future rate cases. Though the Company
16 shows a \$58 million letter of credit associated with the Scotiabank Revolver, the letter of
17 credit can be redirected to the Company's primary JP Morgan Revolver or canceled if tied
18 directly to that revolver. The Company provided scant information on the purpose of the
19 letters of credit and noted that the Letter of Credit was used to cover items such as fuel
20 purchases or margin support for certain services.¹⁰ The Scotiabank Revolver at \$250
21 million has never been used since its inception in 2018 and is way down the pecking

¹⁰ U-21870-Direct testimony of M. Bleckman, p 35.

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1 order of short-term funds to be used if required. The Company will tap its Commercial
2 Paper Facility, and then use internal loans from its parent, then likely its JP Morgan
3 Revolver, before the Scotiabank Revolver is even considered. The amortized inception
4 and unused fees cost ratepayers around \$500 thousand per year, and with the inclusion of
5 the letter of credit, it cost ratepayers \$1 million per year. Even though the Company has
6 not used its \$1.1 billion JP Morgan Revolver in many years, the JP Morgan Revolver
7 does operate as a financial backstop to the Company's \$500 million commercial paper
8 facility. Thus, the JP Morgan Revolver is more than adequate to support the Company's
9 ST-debt needs, letter of credit needs, and any other short-term financing requirements
10 without the expensive and excessive Scotiabank Revolver. Staff is not suggesting that the
11 Commission disallow Consumers from maintaining its Scotiabank Revolver. The
12 Company can preserve its Scotiabank Revolver if it so desires, Staff is just requesting
13 that the Commission disallow the \$1 million in annual costs to be included in the
14 Company's short-term debt cost rate in future rate cases. To buffer its case, Staff
15 provides, as an exhibit in this case, the Company's response to an audit request with
16 regard to the utilization of its Scotiabank Revolver and JP Morgan Revolver from an
17 earlier case.¹¹ The Company responded that it has not borrowed from its Scotiabank or
18 JP Morgan revolvers in recent years, but that it should maintain full capacity of all its
19 facilities. Staff clearly disagrees, as the Scotiabank Revolver is excessive, expensive and
20 is simply unneeded as a tool for Consumers to meet its short-term financing needs. The
21 Commission should disallow all costs associated with the Scotiabank Revolver.

¹¹See Staff Exhibit No. S-4, Schedule D-6, p 1 of 2

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Part II. Return on Equity Analysis

1
2 Q. In establishing a legal base for Staff's return on equity analysis in this rate case, what
3 considerations did Staff take into account?

4 A. Traditionally, when considering a return on equity recommendation for a utility company,
5 Staff considers the legal guidelines from the landmark rulings of Hope and Bluefield.
6 Those cases described various methods such as the "Attraction of Capital" and the
7 "Returns Commensurate with Those on Investments in Enterprises of Comparable Risks"
8 that the Supreme Court found to be lawful and prudent. In *Bluefield Water Works and*
9 *Improvement Co. vs. Public Service Commission*, 262 U.S. 679, 692-693 (1923) case, the
10 Court stated:

11 "A public utility is entitled to such rates as will permit it to earn a return on the value of
12 the property which it employs for the convenience of the public equal to that generally
13 being made at the same time and in the same part of the country on investments in other
14 business undertakings which are attended by corresponding risks and uncertainties; but
15 has no constitutional right to profits such as are realized or anticipated in highly
16 profitable enterprises or speculative ventures."

17 Furthermore, in 1944 in *Federal Power Commission vs. Hope Natural Gas Company*,
18 320 U.S. 591, 603 (1944) case, the Court stated:

19 "From the investor or company point of view, it is important that there be enough revenue
20 not only for operating expenses but also for the capital costs of the business. These
21 include service on the debt and dividends on the stock. By that standard the return to the
22 equity owner should be commensurate with returns on investment in other enterprises

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1 having corresponding risks. That return, moreover, should be sufficient to assure
2 confidence in the financial integrity of the enterprise, so as to maintain its credit and to
3 attract capital.”

4 The Supreme Court established an “end result” doctrine which surmised that how a
5 capital structure and rate of return was determined was not so important as long as the
6 end result was appropriate and reasonable for the case at hand. No one methodology
7 provides an exact measure of a fair rate of return on equity, but some methods provide
8 good estimates. The Discounted Cash Flow method (DCF) and the Capital Asset Pricing
9 Model (CAPM) are the primary models most utility financial analysts use in rate cases to
10 determine a fair and reasonable cost of equity for regulated utility companies. I
11 employed those same methods in this rate case along with a bond yield + risk premium
12 method and a comparison of electric ROE determinations from other state jurisdictions.

13 Q. Please explain the development of the electric utility proxy group you used in your cost
14 of equity analysis for Consumers Energy.

15 A. I primarily looked at six criteria in selecting a proxy group of comparable utility
16 companies used in my ROE analysis: 1) each utility had to have net plant greater than
17 \$10.0 billion but less than \$37.0 billion to better compare in size and footprint to
18 Consumers Energy’s Electric division; 2) each company had to derive no less than
19 approximately 50% or more of its revenues from regulated electric service; 3) each utility
20 had to have an investment grade rating within three-four notches from that of Consumers,
21 mainly from the two primary rating agencies, S&P and Moody’s; 4) each company had to
22 currently be paying dividends to shareholders; 5) each utility had to be followed by 2 or

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1 more International Business Estimating System (I/B/E/S) analysts; and 6) each company
2 was not currently involved in a merger or major corporate buyout or sell-off that could
3 significantly impact the company's stock price.. With this selection criterion, I came up
4 with a list of eight electric utility companies, which are outlined in Exhibit S-4, Schedule
5 D-5, page 2 of 14.

6 Q. How does your proxy group align with the Company's proxy group?

7 A. The Company's proxy group consists of 19 utilities. All the companies in my proxy
8 group are part of the Company's proxy group. However, the Company's proxy group
9 includes companies such as Duke Energy, American Electric Power, Southern Company
10 and some others that are much larger than Consumers and exceed my upper limit of \$37
11 billion in net electric plant. Those super-large utilities are not comparable to Consumers
12 Energy and should have been excluded from the Company's proxy group. Nonetheless,
13 even though Staff does not agree with many of the Company's proxy group members,
14 that is not the primary reason for our differing ROE recommendations.

15 Q. Please provide a brief description of Staff's Exhibit S-4, Schedule D-5, pages 2 - 4.

16 A. Exhibit S-4, Schedule D-5, page 2 provides some business statistics on Consumers
17 Energy and the proxy group utilities used in this case. Columns (e) and (f) describe the
18 credit ratings assigned to each utility by the credit rating agencies S&P and Moody's.
19 The proxy group's average S&P credit rating is (BBB+), which is two notches below
20 Consumers credit rating of (A). Moody's average credit rating for the group is (Baa1),
21 which is three notches below Consumers credit rating of (A1). Thus, CE-Electric has a
22 much higher credit rating and is considered a better credit risk, i.e., safer company than

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1 the proxy group. Column (g) describes the dividend payout ratio of each utility.
2 Consumers Energy dividends out to its parent company 80% of its net income compared
3 to the proxy group's 68% payout ratio. Column (j) highlights the latest allowed return on
4 equity for each electric utility or electric utility subsidiary in the proxy group. Columns
5 (k) and (L) outline the authorized equity layer and the date of the order according to S&P
6 Global Market Intelligence. The average equity layer for the electric proxy group is
7 51.07% and the average authorized ROE is 9.48%. The ROE is considerably less than
8 Consumers Energy's current 9.90% authorized ROE and substantially less than Staff's
9 9.75% ROE recommendation. The 51.0% average equity layer of Staff's proxy group is
10 primarily due to one outlier equity layer, OGE Energy, with an equity layer well over
11 53.0%. Removing that firm, the proxy group's average equity layer would be roughly
12 50.0%, which is in line with Staff's recommendation.

Discounted Cash Flow Model (DCF) Analysis

14 Q. Please provide a brief explanation of the DCF and how it is used in this analysis.

15 A. The DCF method has been a widely used approach for estimating equity investors return
16 demand since the 1960s. The approach derives its basis by surmising how investors
17 evaluate stocks for potential investment. The formula assesses that investors value
18 securities by evaluating the present value of expected future cash flows attributed to those
19 securities. The model suggests that expected future cash flows include dividends, the
20 projected market value of the security at liquidation, and the discount or capitalization
21 rate investors apply to the future cash flows. The model is derived from the formula that
22 evaluates the current price of a stock with the assumption that the growth of the stock will

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1 be constant throughout its life and that its growth will be less than the cost of its equity.

2 The formula is

3 $P = D_1 / k - g$ where:

4 P = Price per share

5 D_1 = Dividend per Share Expected

6 k = Cost of Equity

7 g = Expected Growth Rate

8 Rearranging the above formula into the basic DCF formula is the mathematical equation

9 that states that the cost of equity is equal to the security's dividend yield plus a projected

10 future growth rate of the stock. The basic DCF formula is

11 $K = D_1/P + g$ where:

12 K = Cost of Equity

13 D_1 = Expected Quarterly Dividend Rate Annualized

14 P = Market Price of the Security

15 (D_1/P = Dividend Yield)

16 g = Expected Growth Rate

17 Q. Please explain the computation of your DCF analysis.

18 A. I outline my DCF analysis on Exhibit S-4, Schedule D-5, page 5 of 14. I used June 1,
19 2025, through August 1, 2025, closing stock prices and averaged them for the proxy
20 group. I then annualized the current quarterly paid dividends to calculate dividend yields
21 for the proxy group. The current annual dividend is indicated in column (i). That
22 dividend yield is then modified by the semi-annual compounding method based on the
23 formula $DCF = (D_1/P) * [1 + 0.5g] + g$. The semi-annual compounding model is the
24 preferred model to use when performing a DCF analysis on a group of comparison

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companies.¹² This is also the preferred 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 was gathered from widely used and well-known sources such as Zacks and Value Line. The growth rate estimates are averaged together and range from a low rate of 3.56% to a high of 7.59%. Staff, Consumers, and most other intervenors have traditionally used the 3–5-year growth rate projection data from I/B/E/S noted on the Yahoo Finance website. However, Yahoo Finance decided to discontinue their 3-5-year growth rate forecasts for public use, thus the information is no longer available.

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 9.76%. 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].

Capital Asset Pricing Model (CAPM) Analysis

Q. Please discuss Staff's 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:

$$E(R) = R_f + \beta * [E(R_m) - R_f]$$

Where: $E(R)$ = Expected rate of return on a risky security
 R_f = Risk-free rate of return
 $E(R_m)$ = Expected market rate of return

¹² Parcell, D.C. (1997) *The Cost of Capital – A Practitioner's Guide*, 1997 Edition, Chapter 8, pages 10-13.

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1 β = The systematic risk or beta of a security

2 In theory the CAPM model differentiates between two types of risk, diversifiable and
3 non-diversifiable risk. The theory suggests that an investor's required return is based on
4 the investor's exposure to risk that is systemic in the market, i.e. non-diversifiable risk.

5 Risk that is unique to a particular security is called firm specific risk. One of CAPM's
6 primary assumptions is that investors are fully invested in the market, i.e. invested in a
7 portfolio of stocks, and thus eliminate or substantially reduce firm specific risk. Hence,

8 the model infers that investors risk exposure is primarily composed of market risk and
9 since this is risk that cannot be diversified away, it should be the basis for investor

10 compensation. The beta coefficient measures the volatility of a security's stock price as it
11 relates to changes or movements in the market and extends as the market risk component.

12 Q. Did you provide more than one market risk premium estimate in your CAPM analysis?

13 A. Yes. I used an historical risk premium and two projected market risk premiums. I will
14 discuss the projected risk premium models later in my testimony. In evaluating the

15 historical risk premium, I reviewed the historical equity risk premium data provided by

16 Professor Aswath Damodaran in his Damodaran Online Finance website. [Damodaran On-](#)

17 [line Home Page \(nyu.edu\)](#). The website provides historical value for market return

18 indices used in the estimation of risk premiums and common equity costs. Taking the

19 difference between the 1928-2024 average stock return of the S&P 500 and the

20 government bond return over the same period, indicated a 6.94% market risk premium

21 (MRP). The historical MRP derivation is shown on Exhibit S-4, Schedule D-5, page 6 of

22 14.

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1 Q. What risk free rate (R_f) did you use in your CAPM analysis?

2 A. U.S. Government securities are commonly considered to be risk-free. The risk-free rate
3 used in my CAPM analysis is the yield associated with a long-term U.S. Treasury bond. I
4 reviewed S&P Global Market Base Forecast for 30-year Treasury bond yield forecasts for
5 2025 - 2027, and the average (Dec 31 – Dec 31) forecasts over the same period from
6 Econforecasting.com. I provided 10% weight to the 2025 and 2027 estimates and 80%
7 weight to the 2026 estimate to establish a risk-free rate of 4.58%.

8 Q. What beta did you use in your analysis and its source?

9 A. I used the beta derived from Value Line. By definition, the market beta is 1. The Value
10 Line beta is a forward-looking beta, which measures a 60-month average raw beta on a
11 weekly basis and adjusts that raw beta by a convergence factor towards market beta 1.
12 Stocks with betas less than 1 are considered less volatile and thus less risky than stocks
13 with betas greater than 1.

14 Q. What cost of equity estimate did you arrive at using the historical CAPM method?

15 A. Combining the average risk-free rate of 4.58% with the calculated historical risk
16 premium of 6.94% and the electric group's beta in the CAPM formula
17 $[R_f + \beta \cdot (MRP)]$, I computed an average CAPM cost of equity of 10.05% for the
18 historical period.

19 Q. Did you also provide a Projected CAPM analysis?

20 A. Yes. To account for the forward-looking nature of the CAPM, primarily with respect to
21 market return and equity risk premium derivation, I also conducted a projected CAPM
22 analysis using forward-looking market risk premium estimates provided by Professor

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1 Aswath Damodaran in his Damodaran Online Finance website.

2 Q. Please explain your Projected CAPM analysis.

3 A. Professor Damodaran provides a projected 5-year analysis of the S&P 500, known as the
4 trailing 12-month cash yield market risk premium analysis, as noted in his Implied Risk
5 Premium Calculator. In short, the professor takes a base level of earnings in the S&P 500
6 index and then applies the DCF model to that data, which includes industry expert growth
7 rates, to arrive at a projected overall market return. The professor then subtracts out the
8 projected risk-free rate and determines an implied market risk premium. The professor
9 computes a (3-5 year) projected market risk premium of 4.15%. The professor also
10 computed a 10-year cash-yield smoothed market risk premium analysis of 5.66%. I used
11 both the 4.15% and 5.66% MRPs in my projected CAPM analysis.

12 Q. What projected CAPM cost of equity estimates did you arrive at?

13 A. Combining the average risk-free rate of 4.58% with the projected risk premia of 4.15%
14 and 5.66% and the electric group's betas, I computed two CAPM ROE estimates of
15 7.85% and 9.04%.

16 Q. Are Staff's projected CAPM ROE estimates reasonable in this case?

17 A. Yes. Professor Damodaran's market risk premium data and analysis is thoroughly
18 explained on his website. However, the 12-month cash yield analysis produces an
19 unreasonably low ROE estimate in this case. The smoothed analysis provides a more
20 reasonable CAPM result. Although the trailing 12-month cash yield analysis is low, that
21 was not the case in the Company's last rate case, and Staff believes in the informative
22 nature of both market risk premiums and will continue to use both in future rate cases.

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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 electric utility realized stock returns and historical composite utility bond yields and adds this spread to the projected yield on an A-rated long-term utility bond 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 Historical Electric Utility Realized Market Return Average from 1931 through 2024 compared with the average yield on A-Rated Public Utility Bonds over the same period. The Mergent Public Utility Manual & Bond Record provided complete market return and bond yield data until 2000. To obtain utility market return data beyond year 2000, I used a combination of data from the Dow Jones Utilities index, data from the S&P 500 Utilities Corporate Bond Index, 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 11 of 14. The average electric utility market return over that period was 10.83% and the average A-rated composite utility bond yield was 6.27% over the same period. Subtracting the bond yield from the market return yielded an historical spread of 4.56%. In addition, a Treasury Bond spread of 5.88% was derived over the same historical period 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

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1 projected 2026-2027 A-rated utility bond is 5.67%.¹³ Adding the projected bond yield to
2 the historical market risk premium of 4.56% produces an ROE estimate of 10.23%.
3 Adding the historical Treasury Bond spread of 5.88% to the projected 30-year T-bond
4 yield of 4.58%, produces an ROE estimate of 10.46%. This information is shown on
5 Exhibit S-4, Schedule D-5, page 12 of 14.

6 Q. Did Staff review any other study in its return on equity analysis?

7 A. Yes. As previously referenced, I reviewed the authorized rate of return decisions for
8 electric utilities rendered by other state commissions across the country from 2021
9 through June 2025. The average authorized ROE decision for 2021 was 9.38%, for 2022
10 was 9.54%, for 2023 was 9.60%, for 2024 was 9.74%, and through June of 2025 was
11 9.68%. The full four-year average ROE (2021-2024) is 9.57%, which is well below the
12 9.90% ROE that the Company has been routinely authorized over that same period, and
13 well below Staff's ROE recommendation of 9.75% in this case. The data was derived
14 from the RRA database and is noted on Exhibit S-4, Schedule D-5, page 13 of 14.

15 Q. Is the use of the information in the RRA database helpful in rate cases?

16 A. Yes. The RRA provides up to date electric and gas ROE authorizations from utility rate
17 cases across the United States. The data is pertinent and reliable, and the use of the RRA
18 database as a reasonable measuring stick to compare Staff's ROE model results and ROE
19 recommendation is relevant and useful. It is also reasonable for the Commission to be
20 able to review other state commission average authorized ROEs to see where the general

¹³ S&P Global Market Intelligence – US Economic Outlook Tables, p 52 (Aug. 2025):
Cost of Funds – To Public Utilities: Yr. 2026 = 5.72%, Yr. 2027 = 5.62%: Avg = 5.67%

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landscape of ROEs are presiding during any given rate case. Thus, the use of the database is reliable, 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 electric division in this rate case?

A. Below is a summary of Staff's cost of equity estimates and recommended ROE:

<u>ROE Analysis</u>	<u>ROE</u>
Traditional DCF:	9.76%
Historical CAPM:	10.05%
Projected CAPM – Damodaran – Trailing 12-mnth cash yield ERP:	7.85%
Projected CAPM – Damodaran – 10-yr cash yield (smoothed) ERP:	9.04%
Bond Yield + Risk Premium – Projected A-Rated Utility Bond:	10.23%
Historical Treasury Bond + Projected LT- Treasury. Bond:	10.46%
Avg. Electric Utility Authorized ROE Decisions Across U.S – Jun. 2025:	9.68%
Avg. Electric Utility Authorized ROE Decisions Across the U.S - 2024:	9.74%
Avg. Electric Utility Authorized ROE Decisions Across the U.S - 2023:	9.60%
Avg. Electric Utility Authorized ROE Decisions Across the U.S - 2022:	9.54%
Avg. Electric Utility Authorized ROE Decisions Across the U.S – 2021:	9.38%

Recommended Cost of Equity Range:	9.25% - 10.25%
ROE recommended and used in Overall Cost of Capital	<u>9.75%</u>

Based on the results above, it is Staff's judgment that a cost of equity recommendation for Consumers Energy's Electric 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%. Staff does not agree with the Company's 10.25% ROE recommendation and

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1 will provide a review of the Company's ROE models in the section below.

2 Q. What is the financial impact on ratepayers of a 10.25% ROE compared to a 9.75% ROE?

3 A. According to data provided by Consumers, for every 1 basis points change in the ROE,
4 the difference is \$888,000 per basis point.¹⁴ So, the 50-basis point difference, if the
5 Commission were to adopt the Company's 10.25% ROE as opposed to Staff's 9.75%
6 recommendation, would cost ratepayers an additional **\$44.4** million annually.

7
8 **Staff's Analysis of the CE-Electric's ROE Models**

9 Q. Please explain your discussion in this section.

10 A. I will discuss the Company's DCF, CAPM, ECAPM and Bond Yield + Risk Premium
11 models and provide an assessment of the models, discuss the Company's inputs into the
12 models, and whether the Commission should consider the merits of the model's results.

13 **DCF Discussion**

14 Q. Did Consumers provide a DCF analysis and cost of equity estimate?

15 A. Yes. Company witness Ann Bulkley provides a mean average DCF cost of equity
16 estimate of 10.36% and a median average DCF cost of equity estimate of 10.26%, using
17 the Company's nineteen electric utility proxy group. Ms. Bulkley provides a 30-day, 90-
18 day or 180-day analysis using growth rates from Value Line, S&P Capital IQ and Zacks.

19 Q. Do you agree with the Company's DCF analysis?

20 A. Not entirely. I agree with the analysis in general but disagree with some of the inputs.

21 The Company's average 10.30% ROE estimate using its three different stock price

¹⁴ Consumers Energy audit response to Staff – Audit Response #130

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1 averages is not entirely out of bounds but some of the growth rates are unreasonable. For
2 example, Dominion Resources, Inc. has S&P and Zacks growth rate forecasts of well
3 over 13.0%, while Value Line shows a growth rate of only 3.50%. This indicates that the
4 growth rates are wildly divergent, with two growth rates that appear to be clear outliers.
5 The Dominion outlier growth rates produce a DCF ROE estimate of well over 15.0%,
6 which is clearly unreasonable. Thus, some of the growth rates in the Company's analysis
7 are elevated and unduly boost the mean and median ROE. The Commission should view
8 the Company's DCF analysis with caution.

9 **CAPM Discussion**

10 Q. Please discuss the Company's CAPM analysis and cost of equity estimate?

11 A. The Company provides three CAPM analyses, a projected CAPM analysis and a
12 projected empirical CAPM or ECAPM analysis using Value Line, Bloomberg, and long-
13 term historical beta data. The Company provided a total of 18 ROE estimates.

14 Q. Please explain how the Company derived its CAPM results.

15 A. The Company provides a traditional CAPM analysis that uses Bloomberg and Value Line
16 betas, a current, a near-term and a long-term 30-year risk-free rate, and a projected
17 market risk premium. The Company also provides the same analysis but with the use of
18 a long-term historical average Value Line beta that smoothed the beta results, primarily
19 from the impact of the Covid period. The Company's projected CAPM analysis
20 produced nine ROE estimates with a low of 10.78% to a high of 12.18%.

21 Q. Please discuss the Company's other CAPM approach?

22 A. Consumers also provides an ECAPM approach that modifies the traditional CAPM

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1 approach with the inclusion of an adjustment that purports to better align low beta
2 companies with observed returns in the market.¹⁵ The Company applies a 75% weighting
3 to the CAPM equation with the beta factor incorporated into the market risk premium
4 data and a 25% weighting without the beta incorporated into the market risk premium.

5 The Company calculated nine additional ECAPM ROE estimates with a low of 11.23%
6 to a high of 12.28%.

7 Q. Do you agree with the Company's Projected CAPM and ECAPM analyses?

8 A. No. I disagree with the ECAPM in general and will explain my disagreement later in
9 testimony. The Company uses a projected market return of 12.58% in its analysis, which
10 is at the high-end of prudence. Subtracting the Company's three risk-free rates of 4.30%
11 to 4.61% from the 12.58% market return, provides a market risk premium estimate of
12 7.97% to 8.28%. These market risk premium results are substantially higher than the
13 historical market risk premium of around 7.0% and substantially higher than Professor
14 Damodaran's projected estimates of 4.2 - 6.2%. The Company's inflated data produces
15 overblown CAPM results in the 11.50% range. Those results are overstated and clearly
16 unreasonable, and the Commission should give little to no weight to the inflated MRP
17 used in the Company's CAPM analyses.

18 Q. Are there aspects of the Company's CAPM analysis you agree with?

19 A. Yes. I agree with the Company's use of the Value Line long-term beta in its CAPM
20 analysis. The Company developed its historical long-term beta by averaging the Value

¹⁵ *Id.* at 32.

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1 Line betas annually from year-end 2013 to year-end 2024.¹⁶ This smoothed the current
2 beta values that consider the unreasonably high beta period during the Covid years of
3 2020 – 2021. The long-term averaging produces more reasonable results than the current
4 high Value Line betas values 0.85 – 1.10. Regulated utilities have historically been well
5 below the overall market beta of 1.00. For example, DTE Energy’s beta was as low as
6 0.55 in 2019. By year-end 2020, it surged to 0.95 and was up to 1.00 at year-end 2024. It
7 is abundantly clear that beta values spiked during the Covid period and were
8 unreasonably high without any fundamental change in the basic business operations of
9 the utilities. With that said, even with the use of the smoothed betas, the Company’s
10 CAPM estimates are still unreasonably high because of the excessive market risk
11 premiums used in the Company’s analysis. Very limited weight should be given to the
12 Company’s CAPM analysis and its excessive ROE results.

13 Q. Please explain your disagreement with the Company’s ECAPM approach.

14 A. I disagree with the ECAPM approach in general because ECAPM was established based
15 on the results of the CAPM using substantially different inputs. The ECAPM was
16 established using raw betas and short-term debt metrics. However, the Company’s
17 ECAPM analysis does not use raw betas nor short-term debt metrics, the Company’s
18 analysis uses Value Line and Bloomberg adjusted betas and long-term debt metrics. This
19 change in input renders the need for the ECAPM adjustment unnecessary. As Staff noted
20 earlier in its testimony, Value Line and Bloomberg modifies its beta using the “Blume”
21 adjustment that adjusts beta to account for the tendency to converge toward the market

¹⁶ Company witness A. Bulkley, Exhibit No. A-14, Schedule D-5, p 15 of 31

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beta 1.00. The two entities adjust their beta by using the equation $\beta_{\text{adjusted}} = 0.34 + 0.66 \beta_{\text{raw}}$. To illustrate this difference in a CAPM analysis using modified and unmodified betas, Staff provides a sample analysis below.

Example 1.

Value Line Beta (β_{adjusted}) = 0.70

$$\beta_{\text{adjusted}} = 0.34 + 0.66 \beta_{\text{raw}}$$

$$0.66 \beta_{\text{raw}} = \beta_{\text{adjusted}} - 0.34$$

$$\beta_{\text{raw}} = 0.36 / 0.66 = 0.54$$

Sample Risk-free rate (Rf) = 2.5%

Sample Market Risk Premium (MRP) 7.0%

CAPM using adjusted Value Line beta

$$K = Rf + \beta_{\text{adjusted}} \times \text{MRP}$$

$$K = 2.5\% + (0.70) \times (7.0\%) = \underline{7.40\%}$$

ECAPM using raw beta where $X = 0.34$

$$K = Rf + X \times \text{MRP} + (1 - X) (\beta_{\text{raw}} \times \text{MRP})$$

$$K = 2.5\% + 0.34 \times (7.0\%) + (1 - 0.34) \times (0.54 \times 7.0\%)$$

$$K = 2.5\% + 2.4\% + 2.5\% = \underline{7.40\%}$$

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.

Without consideration of the overblown ROE estimates the ECAPM produces, the

Commission has not considered the merits of the ECAPM approach in past rate cases and

should not consider any merit to the ECAPM approach in this case as well.

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Bond Yield + Risk Premium Discussion

Q. Did the Company provide a Bond Yield + Risk Premium (BYRP) analysis?

A. Yes. The Company provides a BYRP analysis, using previous authorized ROEs as an input into the model along with the use of three 30-yr Treasury Bond yields. The Company's BYRP model produces an average ROE estimate of 10.59%.

Q. Do you agree with the Company's BYRP analysis and ROE result?

A. No. First, the Company's methodology for its BYRP analysis is rather complicated and circular. Second, the Company doesn't even use the average risk premium result they calculated in their BYRP analysis but uses an inflated result instead. In its analysis, the Company uses the average authorized electric utility ROEs from 1980 through the 1st quarter 2025 as the overall market return, compared with the yield on a 30-year U.S. Treasury bond during the same period to develop a risk premium over that period. Throughout the process, 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 historical interest rates and risk premia are inversely correlated. From its analysis, Consumers calculated an average risk premium of 5.44%. However, the Company does not use that number in its BYRP model, it uses elevated 6.06% - 6.19% figures in its analysis instead. The Company applied an additional adder to its risk premium data and witness Bulkley provided no testimony or basis for this adder.¹⁷ Thus, not only is Staff concerned that using historical authorized ROEs as a market return source in a cost of

¹⁷Company witness A. Bulkley, Exhibit No. A-14, Schedule D-5, p 22 of 31

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1 equity model is circular, but then having the Company massage the data to get to its
2 desired result is a nonstarter. The Commission should give no weight to the Company's
3 bond yield + risk premium analysis.

4 Q. Should the inclusion of flotation costs be considered in any of the cost of equity models
5 for the Company?

6 A. No. Flotation cost enhancement to any of the Company's ROE estimates should be
7 rejected. Consumers Energy, as a stand-alone entity, issues and procures its own long-
8 term and short-term debt. In that respect, the Company is allowed to recover all costs
9 associated with those issuances and include those costs in its overall cost of capital
10 determination. However, Consumers Energy, as a subsidiary of its parent company CMS
11 Energy, does not issue its own stock and thus does not incur flotation costs. Therefore, it
12 would be improper to include flotation cost enhancement to any of the Company's cost of
13 equity models.

14 Q. Should the Commission adopt Consumers ROE recommendation in this case?

15 A. No. The Commission should reject the Company's 10.25% recommendation for several
16 reasons. First, the ROE request is 35 basis points higher than the Company's currently
17 authorized 9.90% ROE, which does not coincide with the Commission's request for
18 prudence. Second, the request also does not coincide with Consumers Energy's solid
19 credit rating and the Commission's approval of many of the Company's preferred
20 enhancement programs and the Company's request to further enhance those programs in
21 this rate case. If approved, this treatment will all but ensures recovery of costs associated
22 with those programs and reduce the Company's overall business and financial risk. In

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1 addition, the Company's practice of filing a new rate case no more than 12 months after
2 its prior rate case, even with cases that include a test-year that won't terminate until
3 several months after the filing of this new rate case, borders on a 100% risk-free
4 investment for the Company. This tremendous risk reduction calls for an ROE
5 dramatically less than the Company's 10.25% request and much less than the Company's
6 currently authorized 9.90% ROE. Staff's suitable 9.75% ROE, along with its 50/50
7 capital structure request, properly balances the needs of the Company along with a
8 reasonable level of fairness to the Company's ratepayers.

9 Q. Does this conclude your testimony?

10 A. Yes.

1 MR. SONEVELDT: Next, Your Honor, Staff moves to
2 bind the direct testimony of Robert F. Nichols. Mr.
3 Nichols' direct testimony consists of his cover sheet and
4 eight pages of questions and answers. He sponsors the
5 following exhibits: Exhibit S-1, Schedules A-1 through A-
6 3. Exhibit S-3, Schedules C-1, C-1.1, C-12, and C-13, and
7 then he also sponsors confidential Exhibit S-7.

8 JUDGE THOITS: Are there any objections to the
9 admission to this testimony or these exhibits?

10 Hearing none. The direct testimony of Robert
11 Nichols is bound into the record and exhibits S-1,
12 Schedule A-1 through A-3, Exhibit S-3, Schedule C-1, C-
13 1.1, C-12, and C-13 are admitted to the public record in
14 Exhibit S-7 as admitted to the confidential record.

STATE OF MICHIGAN
BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

Case No. U-21870

In the matter of the application of
CONSUMERS ENERGY COMPANY
for authority to increase its rates for
the generation and distribution of
electricity and for other relief.

QUALIFICATIONS AND DIRECT TESTIMONY OF

ROBERT F. NICHOLS II, CPA

MICHIGAN PUBLIC SERVICE COMMISSION

September 30, 2025

**QUALIFICATIONS AND DIRECT TESTIMONY OF
ROBERT F. NICHOLS II, CPA
U-21870**

1 Q. Please state your name and business address.

2 A. My name is Robert F. Nichols II, and my business address is 7109 West Saginaw
3 Highway, Lansing, MI 48917.

4 Q. By whom are you employed and in what capacity?

5 A. I am employed by the Michigan Public Service Commission (Commission or MPSC) as
6 the Manager of the Revenue Requirements Section of the Regulated Energy Division.

7 Q. How long have you been employed by the MPSC and what are your duties?

8 A. I have been employed by the MPSC since November of 2011. As Manager of the
9 Revenue Requirements Section, I am primarily responsible for the planning and direction
10 of electric and gas rate case audits and presentations, as well as cases involving
11 accounting standards and requests for accounting authority. From 2011 through March
12 2016, as an Auditor within the Revenue Requirements Section, my responsibilities
13 included auditing, analyzing, and making recommendations regarding utility revenues,
14 expenses, and rate base.

15 Q. Please describe your educational background.

16 A. I graduated from Davenport University, with highest honors, in 2009 with a Bachelor of
17 Business Administration degree in Accounting Information Management. I attended a
18 regulation and ratemaking conference hosted by the Michigan State University Institute
19 of Public Utilities (MSU IPU) in May of 2012. In August of 2012, I attended the
20 National Association of Regulatory Utility Commissioners (NARUC) annual two-week
21 Regulatory Studies Program held at Michigan State University. Each August from 2013
22 through 2016 and in 2019, I attended the Annual Regulatory Studies program hosted by

**QUALIFICATIONS AND DIRECT TESTIMONY OF
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U-21870**

MSU IPU. I also attended a one-week Advanced Regulatory Studies Program in the 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:

<u>Case No.</u>	<u>Company</u>	<u>Subject/Type</u>
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

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1	U-18419	DTE Electric Company	Certificate of Necessity
2	U-18424	Consumers Energy Co. Gas	Rate Case
3	U-18999	DTE Gas Company	Rate Case
4	U-20111	Upper Peninsula Power Co.	TCJA Credit A Case
5	U-20268	Alpena Power Company	TCJA Credit B Case
6	U-20134	Consumers Energy Co. Electric	Rate Case
7	U-20287	Consumers Energy Co. Gas	TCJA Credit B Case
8	U-20165	Consumers Energy Co. Electric	Integrated Resource Plan
9	U-20162	DTE Electric Company	Rate Case
10	U-20276	Upper Peninsula Power Co.	Rate Case
11	U-20322	Consumers Energy Co. Gas	Rate Case
12	U-20350	Upper Peninsula Power Co.	Integrated Resource Plan
13	U-20479	SEMCO Energy Gas Co.	Rate Case
14	U-20359	Indiana Michigan Power Co.	Rate Case
15	U-20561	DTE Electric Company	Rate Case
16	U-20642	DTE Gas Company	Rate Case
17	U-20650	Consumers Energy Co. Gas	Rate Case
18	U-20697	Consumers Energy Co. Electric	Rate Case
19	U-20713	DTE Electric Company	Voluntary Green Pricing
20	U-21015	DTE Electric Company	Securitization Case
21	U-20940	DTE Gas Company	Rate Case
22	U-20963	Consumers Energy Co. Electric	Rate Case
23	U-21090	Consumers Energy Co. Electric	Integrated Resource Plan
24	U-21148	Consumers Energy Co. Gas	Rate Case
25	U-20836	DTE Electric Company	Rate Case
26	U-20993	Saginaw Bay Pipeline Co.	Rates for Transportation
27	U-21224	Consumers Energy Co. Electric	Rate Case
28	U-21286	Upper Peninsula Power Co.	Rate Case
29	U-21193	DTE Electric Company	Integrated Resource Plan
30	U-20827	DTE Electric Company	PSCR Reconciliation
31	U-21308	Consumers Energy Co. Gas	Rate Case
32	U-21297	DTE Electric Company	Rate Case
33	U-21389	Consumers Energy Co. Electric	Rate Case
34	U-21461	Indiana Michigan Power Co.	Rate Case
35	U-21525	DTM Michigan Lateral Co.	Rate Request
36	U-21490	Consumers Energy Co. Gas	Rate Case
37	U-21291	DTE Gas Company	Rate Case
38	U-21540	Michigan Gas Utilities Corp.	Rate Case
39	U-21555	Upper Peninsula Power Co.	Rate Case
40	U-21534	DTE Electric Company	Rate Case
41	U-21585	Consumers Energy Co. Electric	Rate Case
42	U-21258	Consumers Energy Co. Electric	PSCR Reconciliation
43	U-21806	Consumers Energy Co. Gas	Rate Case
44	U-21860	DTE Electric Company	Rate Case

**QUALIFICATIONS AND DIRECT TESTIMONY OF
ROBERT F. NICHOLS II, CPA
U-21870**

1 Q. What is the purpose of your testimony?

2 A. The purpose of my testimony is to present the MPSC Staff's (Staff) projected revenue
3 deficiency, projected net operating income, Campbell regulatory asset – return on,
4 forestry ramp-up O&M deferral, and Staff's position on the SAP S/4HANA
5 implementation project O&M deferral request for Consumers Energy Company
6 (Consumers Energy or the Company).

7 Q. Are you sponsoring any exhibits?

8 A. Yes. I am sponsoring the following exhibits:

9 Exhibits:

10 S-1 Schedule A-1: Revenue Deficiency (Sufficiency)

11 S-1 Schedule A-2: Campbell Regulatory Asset – Return On

12 S-1 Schedule A-3: Forestry Ramp-Up Revenue Deficiency Impact of O&M Deferral

13 S-3 Schedule C-1: Adjusted Net Operating Income

14 S-3 Schedule C-1.1: Development of Adjusted Net Operating Income

15 S-3 Schedule C-12: Income Tax Effect of Interest

16 S-3 Schedule C-13: Interest Synchronization Adjustment

17 S-7 **CONFIDENTIAL** SAP S/4HANA Implementation Project – Revenue
18 Deficiency Impact of O&M Deferral

19 **REVENUE DEFICIENCY:**

20 Q. Referring to Exhibit S-1, Schedule A-1, what is Staff's projected revenue deficiency?

21 A. Staff projects a revenue deficiency of \$322,731,000, a revenue requirement decrease of
22 \$113,150,000 from the Company's originally filed revenue deficiency of \$435,881,000.

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1 Exhibit A-11 (PDD-28), Schedule A1. The main factors driving Staff's overall
2 adjustment are Staff's lower rate base, its higher net operating income, and its lower
3 required rate of return. In addition to my testimony, other Staff witnesses provide
4 testimony and supporting exhibits regarding the adjustments to the Company's revenue
5 deficiency.

6 **CAMPBELL REGULATORY ASSET – RETURN ON:**

7 Q. Referring to Exhibit S-1, Schedule A-2, what is Staff's Campbell regulatory asset – return
8 on revenue requirement?

9 A. Staff's Campbell regulatory asset – return on revenue requirement is \$76,568,000, which
10 is \$917,000 less than the Company's \$77,486,000 revenue requirement. (Exhibit S-1,
11 Schedule A-2; Exhibit A-81 (PDD-57).) Staff is projecting a lower Campbell revenue
12 requirement because Staff has applied its proposed cost of capital from Exhibit S-4,
13 Schedule D1 with a 9% return on equity (ROE) applied for Campbell per the Order in
14 MPSC Case No. U-21090 in lieu of the Company's projection. Staff and the Company
15 have both applied 9% ROE per the U-21090 Order. Staff recommends the Campbell
16 revenue requirement adjustment should be updated by the Commission to reflect its final
17 authorized cost of capital in this case, but with the ROE set at 9% per the Commission's
18 previous Order in MPSC Case No. U-21090.

19 **FORESTRY RAMP-UP O&M DEFERRAL:**

20 Q. Referring to Company witness Daly's testimony at page 34-36 and Exhibit A-82 (PDD-
21 58), does Staff support the Company's requested accounting treatment to defer
22 \$21,365,000 forestry ramp-up O&M expense?

**QUALIFICATIONS AND DIRECT TESTIMONY OF
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U-21870**

1 A. Yes, Staff supports the requested accounting treatment to defer \$21,365,000 forestry
2 ramp-up O&M expense. Staff has recalculated the revenue deficiency impact by
3 applying the Staff's recommended short-term debt rate as supported by Staff witness
4 Evans (Exhibit S-4, Schedule D-1) and calculates a revenue deficiency reduction of
5 \$21,691,000 as found on Exhibit S-1, Schedule A-3. Staff recommends that if the
6 Commission approves the deferral, that it recalculates the revenue deficiency impact
7 based on its final decisions. If approved, Staff notes that this is an additional incremental
8 revenue deficiency reduction that is not reflected in the Staff's \$322,731,000 revenue
9 deficiency found on Exhibit S-1, Schedule A-1.

10 **NET OPERATING INCOME:**

11 Q. Referring to Exhibit S-3, Schedule C-1, what is Staff's projected net operating income?

12 A. Staff's projected net operating income is \$737,882,000, an increase of \$30,136,000 from
13 the Company's originally filed net operating income of \$707,746,000. Exhibit A-13
14 (PDD-36), Schedule C-1. The main factors driving Staff's overall adjustment are its
15 increase to sales revenue with PSCR offset and its reduction to O&M expense,
16 depreciation and amortization expense, and property tax expense. Details of Staff's
17 adjustments to net operating income, including the names of each Staff witness
18 sponsoring and explaining the adjustment, can be found on Exhibit S-3, Schedule C-1.1.

19 **INTEREST SYNCHRONIZATION:**

20 Q. Please describe Exhibit S-3, Schedule C-12.

21 A. Exhibit S-3, Schedule C-12, shows the calculation of the tax effect of the pro-forma
22 interest adjustment for the projected test year.

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1 Q. Please describe Exhibit S-3, Schedule C-13.

2 A. Exhibit S-3, Schedule C-13, shows the calculation of the tax effect of the interest
3 synchronization adjustment for the projected test year.

4 **SAP S/4HANA IMPLEMENTATION PROJECT O&M DEFERRAL:**

5 Q. Referring to Company witness Myers' testimony at page 16 and Confidential Exhibit A-
6 86 (PDD-62), does Staff support the Company's requested accounting treatment to defer
7 SAP S/4HANA Implementation Project O&M expense, which would reduce the revenue
8 requirement by approximately \$14.6 million?

9 A. Yes, Staff supports the requested accounting treatment to defer SAP S/4HANA
10 Implementation Project O&M expense, which would reduce the revenue requirement by
11 approximately \$14.6 million. Staff has recalculated the revenue deficiency impact by
12 applying the Staff's recommended cost of capital and calculates a revenue deficiency
13 reduction that is slightly different than the Company, which can be on Confidential
14 Exhibit S-7. Staff recommends that if the Commission approves the deferral, that it
15 recalculates the revenue deficiency impact based on its final decisions. If approved, Staff
16 notes that this is an additional incremental revenue deficiency reduction that is not
17 reflected in the Staff's \$322,731,000 revenue deficiency found on Exhibit S-1, Schedule
18 A-1.

19 **SUMMARY:**

20 Q. Please summarize Staff's recommendations.

21 A. Staff recommends the following:

- 22
 - Projected revenue deficiency of \$322,731,000. (Exhibit S-1, Sch. A-1, line 10.)

**QUALIFICATIONS AND DIRECT TESTIMONY OF
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- 1 • Campbell regulatory asset – return on of \$76,658,000. (Exhibit S-1, Schedule A-
2 2, line 5.)
- 3 • Supports the forestry ramp-up O&M deferral of \$21,691,000, which is an
4 additional incremental revenue deficiency reduction that is not reflected in the
5 Staff’s \$322,731,000 projected revenue deficiency. (Exhibit S-1, Schedule A-3,
6 line 8.)
- 7 • Net operating income of \$737,882,000. (Exhibit S-3, Schedule C-1, line 19.)
- 8 • Supports the SAP S/4HANA Implementation Projection O&M expense deferral,
9 which is an additional incremental revenue deficiency reduction that is not
10 reflected in the Staff’s \$322,731,000 projected revenue deficiency. (Confidential
11 Exhibit S-7, line 6.)
- 12 Q. Does this conclude your testimony?
- 13 A. Yes.

1 MR. SONNEVELDT: Next, Your Honor, Staff moves
2 to bind in the direct testimony of Mark J. Pung. Mr.
3 Pung's direct testimony consists of a cover sheet and 11
4 pages of questions and answers. He sponsors Exhibit S-6,
5 Schedules F-1.1, F-1.5, and F-1.6.

6 JUDGE THOITS: Are there any objections to the
7 admission of this testimony or these exhibits?

8 Hearing none. The direct testimony of Mark Pung
9 is bound into the record and exhibits, excuse me, Exhibit
10 S-6, Schedules F-1.1, F-1.5, and F-1.6 are admitted.
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STATE OF MICHIGAN
BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

Case No. U-21870

In the matter of the application of
CONSUMERS ENERGY COMPANY
for authority to increase its rates for
the generation and distribution of
electricity and for other relief.

QUALIFICATIONS AND DIRECT TESTIMONY OF

MARK J. PUNG

MICHIGAN PUBLIC SERVICE COMMISSION

September 30, 2025

**QUALIFICATIONS AND DIRECT TESTIMONY OF
MARK J. PUNG
U-21870**

1 Q. Please state your name and business address.

2 A. My name is Mark J. Pung. My business address is 7109 West Saginaw Highway,
3 Lansing, Michigan 48917.

4 Q. By whom are you employed and in what capacity?

5 A. I am employed by the Michigan Public Service Commission (MPSC or Commission) as a
6 Departmental Specialist in the Rates and Tariff Section of the Regulated Energy Division.
7 I serve as the section's Electric Cost of Service Specialist.

8 Q. Please briefly describe your educational background.

9 A. I graduated from Michigan State University in 2004 with a Bachelor of Arts degree in
10 Supply Chain Management.

11 Q. Have you completed any other courses?

12 A. Yes, I have completed two graduate courses at Central Michigan University's Lansing
13 campus, Quantitative Applications in Administrative Decision Making and Financial
14 Management. I have also completed the Association of Edison Illuminating Company's
15 Fundamentals of Customer Load Data Analysis course, the National Association of
16 Regulatory Utility Commissioners (NARUC) Annual Regulatory Studies Program held at
17 Michigan State University, and EUCI Electric Cost-of-Service Course - Essential
18 Concepts for a Changing Industry.

19 Q. What are your current responsibilities at the MPSC?

20 A. As the Electric Cost of Service Specialist, I am responsible for developing Staff electric
21 cost of service studies, interpreting and applying laws related to electric cost-of-service,
22 and any other electric cost-of-service-related issues in cases before the Commission

**QUALIFICATIONS AND DIRECT TESTIMONY OF
MARK J. PUNG
U-21870**

under the supervision of the Rates and Tariff Section Manager.

Q. Have you previously presented testimony or participated in utility cases before the MPSC?

A. Yes. I have participated in the following cases:

<u>Case No.</u>	<u>Utility</u>	<u>Description</u>
U-14270-R	Presque Isle, Cherryland, Tri-County, and Great Lakes	PSCR Reconciliation
U-14637	Presque Isle Electric and Gas Cooperative	Rate Design
U-14710-R	Presque Isle, Cherryland, Tri-County, and Great Lakes	PSCR Reconciliation & TIER Audit
U-14713-R	Ontonagon County REA	Rate Design
U-14745	Upper Peninsula Power Company	Rate Design
U-14790	Great Lakes Energy Cooperative	Rate Design
U-14893	SEMCO Energy Gas Company	Rate Design
U-15071	Wisconsin Electric Power Company	Rate Design
U-15114	Wisconsin Public Service Corp.	Ex parte of new rate
U-15244	DTE Electric Company	Rate Design
U-15245	Consumers Energy Company	Rate Design
U-15487	Alpena Power Company	Ex parte of new rate
U-15500	Wisconsin Electric Power Company	Rate Design
U-15645	Consumers Energy Company	Rate Design
U-15981	Wisconsin Electric Power Company	Rate Design
U-15988	Upper Peninsula Power Company	Rate Design
U-16180	Indiana Michigan Power Company	Rate Design
U-16472	DTE Electric Company	Rate Design
U-16794	Consumers Energy Company	Rate Design
U-16860	Consumers Energy Company	Revenue Decoupling
U-16877	Michigan Consolidated Gas Company	Revenue Decoupling
U-17043	Consumers Energy Company	VHWF
U-17087	Consumers Energy Company	Rate Design
U-17221	Michigan Gas Utilities Corporation	Revenue Decoupling
U-17222	Michigan Gas Utilities Corporation	Un-collectables
U-17479	Tilden Mining Company	RAS-1 Tariff
U-17530	DTE Michigan Gathering Company	Ex parte of new rate
U-17547	Michigan Gas Utilities Corporation	Revenue Decoupling
U-17686	Michigan Gas Utilities Corporation	Tariff Revisions
U-17688	Consumers Energy Company	Act 169 Case
U-17735	Consumers Energy Company	Rate Design
U-17895	Upper Peninsula Power Company	Rate Design

**QUALIFICATIONS AND DIRECT TESTIMONY OF
MARK J. PUNG
U-21870**

	<u>Case No.</u>	<u>Utility</u>	<u>Description</u>
1			
2	U-17990	Consumers Energy Company	Rate Design
3	U-18255	DTE Electric Company	Rate Design
4	U-18462	Northern States Power Company	Rate Design
5	U-20101	Alpena Power Company	TCJA Credit A
6	U-20108	Northern States Power Company	TCJA Credit A
7	U-20110	Upper Michigan Energy Resource Corp.	TCJA Credit A
8	U-20111	Upper Peninsula Power Company	TCJA Credit A
9	U-20162	DTE Electric Company	Rate Design
10	U-20359	Indiana Michigan Power Company	Rate Design
11	U-20697	Consumers Energy Company	Rate Design
12	U-21045	Alpena Power Company	Rate Design
13	U-21097	Northern States Power Company	Rate Design
14	U-20836	DTE Electric Company	Rate Design
15	U-21224	Consumers Energy Company	Cost of Service
16	U-21297	DTE Electric Company	Cost of Service
17	U-21389	Consumers Energy Company	Cost of Service
18	U-21488	Alpena Power Company	Cost of Service
19	U-21534	DTE Electric Company	Cost of Service
20	U-21541	Upper Michigan Energy Resource Corp.	Cost of Service
21	U-21860	DTE Electric Company	Cost of Service

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**QUALIFICATIONS AND DIRECT TESTIMONY OF
MARK J. PUNG
U-21870**

1 Q. What is the purpose of your testimony?

2 A. The purpose of my testimony is to present MPSC Staff's (Staff) class cost-of-service
3 study (COSS), which allocates Staff's recommended test-year revenue requirements to
4 Consumers Energy's (the Company) customer classes. I will also cover the following: 1)
5 Staff's position on the Company's proposed expansion of distribution cost categories in
6 the COSS based upon its Electric Asset Categorization (EAC) report, 2) Staff's State
7 Reliability Mechanism (SRM) capacity cost revenue requirement and Capacity Charge,
8 4) Staff's recommendations concerning the SRM true-up provision, 5) Staff's Substation
9 Ownership Credits.

10 Q. Are you sponsoring any exhibits?

11 A. Yes, I am sponsoring the following exhibits:
12 Exhibit S-6, Schedule F-1.1, "Staff's Electric Cost-of-Service Study"
13 Exhibit S-6, Schedule F-1.5, "Staff's Capacity Related Cost and Charge Calculation"
14 Exhibit S-6, Schedule F-1.6, "Staff's Substation Ownership Credit"

15 Q. Were these exhibits prepared by you or under your direction?

16 A. Yes, they were.

17 Q. How has Staff modified the Company's test year COSS?

18 A. Where Staff is recommending adjustments, Staff has replaced the Company's inputs with
19 Staff's inputs so that the resulting COSS shows Staff's proposed revenue requirement.

20 Q. How are the results of Staff's COSS incorporated into Staff's case?

21 A. Staff witness Madison Todd utilized the results of Staff's COSS and has designed rates to
22 collect the appropriate amount of revenue for each customer class.

**QUALIFICATIONS AND DIRECT TESTIMONY OF
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Production Allocator

3 Q. Is Staff recommending a change to the production allocator in this case?

4 A. No, it is not.

5 Q. Does Staff have any recommendations concerning the production allocator?

6 A. Staff recommends the Company run and present the standard coincident-peak tests in its
7 next rate case with the most recent available data and provide some insight as to how it
8 views seasonal or monthly loads growing in the future.

9

10

Distribution Cost Categories

11 Q. Is the Company proposing any changes to the distribution cost categories in the
12 Company's cost-of-service study?

13 A. Yes. The Company is proposing to update and expand the distribution cost categories
14 under each FERC account for land, lines, and substation assets in the cost-of-service
15 study to align with the results of its Electric Asset Categorization (EAC) report. The
16 Company explains that the EAC report is provided by property accounting and breaks out
17 distribution plant and related depreciation accounts into more detailed categories. The
18 Company's proposal is found in the direct testimony of Company witness Davis, pages 8
19 through 14.

20 Q. What is Staff's position on the Company's proposal?

21 A. Staff takes no issue with the Company's proposal as it breaks distribution costs into more
22 detailed categories and provides a result that is more aligned with the cost to serve by

**QUALIFICATIONS AND DIRECT TESTIMONY OF
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voltage level.

SRM Capacity Revenue Requirement and Charge

Q. Does the Company's SRM capacity revenue requirement calculation comply with the Commission Order in the Company's previous case, Case No. U-21585?

A. Yes, it does. The Company has included the true-up method that was Ordered in Case No. U-21585.

Q. What is Staff's recommended SRM capacity revenue requirement and capacity charge if using the Company's calculation as filed?

A. Staff's capacity revenue requirement and charge are provided and compared with the Company's in the following table:

SRM Capacity: (000)	Company Filed	Staff's Case	Difference
Revenue Requirement	\$417,794	\$402,762	\$(15,032)
Capacity Charge per MW-Day	\$116.17	\$111.99	(\$4.18)

SRM Capacity Charge True-Up Provision

Q. What is the SRM capacity true-up provision?

A. The SRM capacity true-up provision is a mechanism designed to reconcile the Company's projected amounts included in the capacity charge net of projected fuel costs for energy market sales, off-system energy sales, ancillary services and energy sales under unit-specific bilateral contracts with the actual amounts that occur within the

**QUALIFICATIONS AND DIRECT TESTIMONY OF
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1 period. The capacity charge true-up provision is found in section 6w (4) of PA 341 and
2 states as follows:

3 The commission shall provide for a true-up mechanism that results in a utility
4 charge or credit for the difference between the projected net revenues described in
5 subsection (3) and the actual net revenues reflected in the capacity charge. The
6 true-up shall be reflected in the capacity charge in the subsequent year. The
7 methodology used to set the capacity charge shall be the same methodology used
8 in the true-up for the applicable planning year.

9 Q. How has the Company previously interpreted the SRM true-up provision contained in PA
10 341?

11 A. The Company has previously interpreted this provision as only being required if the SRM
12 capacity charge was actually paid by a customer. Under this interpretation, there is only
13 amounts subject to be trued up if the capacity charge is actually administered and actual
14 revenue collected. The SRM true-up provision does not apply when there is no capacity
15 charge administered to a customer and thus no revenue to true-up. Since the inception of
16 the SRM, the Company had not included a true-up in its capacity charge calculation
17 because no customer to date has been subject to the capacity charge. The Company has
18 included a true-up calculation for the first time in the instant case in compliance with the
19 Commission Order in Case U-21585.

20 Q. How has Michigan's other large electric utility, DTE Electric (DTE), interpreted the SRM
21 true-up provision?

22 A. DTE originally took a formulaic approach to the SRM true-up provision and interpreted
23 the provision as necessary even if no customers were assessed the capacity charge. Using
24 this formulaic method, DTE reconciled their projected amounts net of fuel costs with
25 those that occurred in the actual period and included the reconciled amount in the

**QUALIFICATIONS AND DIRECT TESTIMONY OF
MARK J. PUNG
U-21870**

1 calculation for the capacity charge in the subsequent year. This was done even though
2 they never charged a customer the capacity charge and there was no actual revenue to
3 reconcile.

4 Q. Did DTE propose a different SRM true-up method in its previous rate case, Case U-
5 21534?

6 A. Yes. In Case U-21534, DTE provided an SRM calculation that did not include the
7 formulaic true-up calculation as it had previously. This was a shift to the interpretation
8 that the SRM true-up provision is only necessary if a customer pays the capacity charge.

9 Q. Does Staff have concerns about the formulaic true-up method?

10 A. Yes. The formulaic true-up method has significant flaws. Up to this point, no customer
11 has ever been charged the capacity charge and therefore no revenue has been collected as
12 a result of it. There are no actual revenues to true-up. However, the formulaic true-up
13 method has the potential to throw the capacity and non-capacity revenue requirements far
14 off the cost-to-serve. This is evident in the current DTE electric case, Case No. U-21860,
15 where \$1.12 billion of power supply revenue requirement is being shifted from non-
16 capacity to capacity due solely to the formulaic true-up method. The cause is a large
17 discrepancy between DTE's forecasted amounts in subsection 3, the largest being energy
18 market sales, and the actual amounts that occurred in 2024. These results from the
19 formulaic interpretation of the SRM true-up provision are not reasonable and in Staff's
20 opinion are no longer based on cost-of-service.

21 Q. What impact does the formulaic true-up method have on the SRM capacity revenue
22 requirement and capacity charge calculation in this case?

**QUALIFICATIONS AND DIRECT TESTIMONY OF
MARK J. PUNG
U-21870**

A. The results of the SRM calculation with and without the formulaic true-up are shown in the following table:

SRM Capacity: No True-up (000)	Company Filed	Staff's Case	Difference
Revenue Requirement	\$878,794	\$863,399	\$(15,396)
Capacity Charge per MW-Day	\$244.36	\$240.08	(\$4.28)
SRM Capacity: Formulaic True-up (000)			
Revenue Requirement	\$417,794	\$402,762	\$(15,032)
Capacity Charge per MW-Day	\$116.17	\$111.99	(\$4.18)

Q. What do these results show?

A. The results in this case demonstrate the large swings in the capacity revenue requirement due to the formulaic SRM true-up method. In this case, the formulaic true-up is actually reducing the capacity revenue requirement by \$461 million, artificially lowering the capacity charge.

Q. What is Staff's recommendation concerning the SRM true-up provision?

A. In Staff's opinion, the current formulaic true-up method is not producing a reasonable result that adheres to cost-of-service principles. While I am not speaking as an attorney, Staff believes there is flexibility in how the Commission provides for a true-up mechanism under Section 6w(4) of PA 341. Staff will further address its interpretation in briefing. If no customer pays the capacity charge, there are no revenues to true-up. Staff

**QUALIFICATIONS AND DIRECT TESTIMONY OF
MARK J. PUNG
U-21870**

1 recommends the Commission determine that a true-up is only necessary if a customer is
2 actually subject to the capacity charge and there is actual revenue to reconcile. This is
3 how the Company previously interpreted and applied the SRM true-up provision and this
4 is how the true-up provision should be provided for going forward.

Substation Ownership Credit

7 Q. What method did the Company use to calculate its Substation Ownership Credits?

8 A. The Company used the same method to calculate its Substation Ownership Credits as was
9 approved by the Commission in MPSC Case No. U-18322. The Company's calculation
10 can be found on Company Exhibit A-88 (EAD-4). This method takes the substation costs
11 that have been allocated to GPD, GPTU, and EIP customers on Voltage 1 and Voltage 2
12 and determines the cost on a per kW basis for each voltage level. Lines 1 through 5
13 provide the different items included in the substation rate base, with the total substation
14 rate base shown on line 6. The substation rate base is then multiplied by the pre-tax return
15 rate in line 7 to arrive at the pre-tax return in dollars on line 8. Various expenses (lines 9
16 through 11) and revenue credits (line 12) are added to the pre-tax return to arrive at the
17 total substation revenue requirement by voltage on line 13. This total is divided by the
18 maximum demand in MW for each rate and voltage level (line 14) to determine the
19 Substation Ownership Credit on line 15.

20 Q. How did Staff calculate its Substation Ownership Credits?

21 A. Staff used the same method as the Company to calculate its Substation Ownership
22 Credits but updated for Staff's revenue requirement. Staff's Substation Ownership

**QUALIFICATIONS AND DIRECT TESTIMONY OF
MARK J. PUNG
U-21870**

1 Credits are reflected on Staff Exhibit S-6, Schedule F1.6, Line 15. Staff recommends the
2 Commission approve Staff's Substation Ownership Credits.

Summary

5 Q. Please summarize your recommendations in this proceeding.

6 A. Staff's recommendations are as follows:

7 1. Staff recommends the Company run and present the standard coincident-peak tests in
8 its next rate case.

9 2. Staff takes no issue with the Company's proposal to update and expand the distribution
10 cost categories under each FERC account in the Company's COSS.

11 3. Staff's capacity revenue requirement based on Staff's case and including a formulaic
12 true-up is \$402.8 million and results in a SRM capacity charge of \$111.99 per MW-Day.

13 Staff's capacity revenue requirement without a formulaic true-up is \$863.4 million and
14 results in a SRM capacity charge of \$240.08 per MW-Day.

15 4. Staff recommends the Commission determine that the SRM true-up provision found in
16 section 6(w)4 of PA 341 is only necessary if a customer is actually subject to the capacity
17 charge and there is actual revenue to reconcile.

18 5. Staff recommends the Commission approve Staff's Substation Ownership Credits.

19 Staff used the same method as the Company to calculate its Substation Ownership
20 Credits but updated for Staff's revenue requirement.

21 Q. Does this conclude your testimony?

22 A. Yes, it does.

1 MR. SONNEVELDT: Next, Your Honor, that moves to
2 bind in the direct testimony of Shannon Rueckert. Mr.
3 Rueckert's testimony consists of a cover sheet and three
4 pages of questions and answers. He sponsors no exhibits.

5 JUDGE THOITS: Are there any objections to the
6 admission to this testimony?

7 Hearing none. The direct testimony of Shannon
8 Rueckert is bound into the record.

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STATE OF MICHIGAN
BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

Case No. U-21870

In the matter of the application of
CONSUMERS ENERGY COMPANY
for authority to increase its rates for
the generation and distribution of
electricity and for other relief.

QUALIFICATIONS AND DIRECT TESTIMONY OF

SHANNON RUECKERT

MICHIGAN PUBLIC SERVICE COMMISSION

September 30, 2025

**QUALIFICATIONS AND DIRECT TESTIMONY OF
SHANNON RUECKERT
U-21870**

1 Q. Please state your name and business address.

2 A. My name is Shannon Rueckert. My business address is 7109 W. Saginaw Hwy, Lansing,
3 MI 48917.

4 Q. By whom are you employed and in what capacity?

5 A. I am employed by the Michigan Public Service Commission (MPSC or Commission) as
6 an auditor in the Revenue Requirements section.

7 Q. How long have you been employed by the Commission?

8 A. I have been employed since February of 2018.

9 Q. What is your educational and professional background?

10 A. I previously served in the US Air Force as a Fuels Resource Controller, responsible for
11 controlling base wide fuels operations and accounting. My duties included daily close
12 out and reconciliation of all fuel transactions. After serving in the Air Force, I managed a
13 family business. While general manager of the business I performed all managerial
14 accounting functions. In 2015, I graduated from the University of Michigan with a
15 Bachelor of Business Administration and a concentration in accounting degree with High
16 Honors. I was previously employed at Andrew's Hooper Pavlik, PLC as a staff
17 accountant where I performed tax preparation and audits of municipalities, retirement
18 plans, and banks. In April of 2019 I completed the Master of Business Administration
19 program, with a concentration in accounting, at the University of Michigan. I have been
20 involved in rate case audits and performed audit work in the following cases:

	<u>Case No.</u>	<u>Company / Type of Case</u>
22	U-20276	Upper Peninsula Power Company Electric Rate Case
23	U-20286	Consumers Energy Company's Tax Cuts and Jobs Act (TCJA) Credit B

**QUALIFICATIONS AND DIRECT TESTIMONY OF
SHANNON RUECKERT
U-21870**

1	U-20322	Consumers Energy Gas Rate Case
2	U-20359	Indiana Michigan Company Electric Rate Case
3	U-20642	DTE Gas Rate Case
4	U-20650	Consumers Energy Gas Rate Case
5	U-20697	Consumers Energy Electric Rate Case
6	U-20836	DTE Electric Rate Case
7	U-20940	DTE Gas Rate Case
8	U-20963	Consumers Energy Gas Rate Case
9	U-20995	UPPCo Transfer of Control Case
10	U-21045	Alpena Electric Company
11	U-21097	NSP Electric Company
12	U-21148	Consumers Energy Electric Rate Case
13	U-21194	Detroit Thermal Transfer of Control Case
14	U-20836	DTE Electric Rate Case
15	U-21224	Consumers Energy Electric Rate Case
16	U-21286	Upper Peninsula Power Company Electric Rate Case
17	U-21297	DTE Electric Rate Case
18	U-21308	Consumers Energy Gas Rate Case
19	U-21366	Michigan Gas Utilities
20	U-21389	Consumers Energy Electric Rate Case
21	U-21461	Indiana Michigan Company Electric Rate Case
22	U-21490	Consumers Energy Gas Rate Case
23	U-21291	DTE Gas Rate Case
24	U-21540	Michigan Gas Utilities Rate Case
25	U-21541	Upper Michigan Energy Resources Electric Rate Case
26	U-21555	Upper Peninsula Power Company Electric Rate Case
27	U-21534	DTE Electric Rate Case
28	U-21565	NSP Electric Rate Case
29	U-21585	Consumers Energy Electric Rate Case
30	U-21806	Consumers Energy Gas Rate Case
31	U-21860	DTE Electric Rate Case
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33	Q.	What is the purpose of your testimony?
34	A.	The purpose of my testimony is to present Staff recommendations relating to the
35		Company's request for a one-way tracker for the River Hydro O&M expense.
36	Q.	Does Staff support the Company's request for approval of a one-way tracker for the River
37		Hydro O&M expense?
38	A.	Yes. Company witness explained that the purpose of the tracker is only to refund the
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**QUALIFICATIONS AND DIRECT TESTIMONY OF
SHANNON RUECKERT
U-21870**

- 1 difference between the projected River Hydro O&M expense and the actual expense. And
2 that the Company does not propose to recover additional O&M expenses should they
3 exceed the projection. See the direct testimony of Richard T. Blumenstock, page 109.
4 Staff reviewed the Company's request and considered it reasonable. Staff recommends
5 the Commission's approval as requested.
- 6 Q. Does this complete your testimony?
- 7 A. Yes.

1 MR. SONNEVELDT: Next, Your Honor, Staff moves
2 to bind in the direct testimony of Michelle Schreur. Ms.
3 Schreur's testimony consists of a cover sheet and three
4 pages of questions and answers. She also sponsors Exhibit
5 S-3, Schedule C-5, and, by my notes, that should complete
6 the entirety of Exhibit S-3.

7 MR. THOITS: Are there any objections to the
8 admission of this testimony or this exhibit?

9 Hearing none. The direct testimony Michelle
10 Schreur is bound into the record, and Exhibit S-3 is
11 admitted.

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STATE OF MICHIGAN
BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

Case No. U-21870

In the matter of the application of
CONSUMERS ENERGY COMPANY
for authority to increase its rates for
the generation and distribution of
electricity and for other relief.

QUALIFICATIONS AND DIRECT TESTIMONY OF

MICHELLE L. SCHREUR

MICHIGAN PUBLIC SERVICE COMMISSION

September 30, 2025

**QUALIFICATIONS AND DIRECT TESTIMONY OF
MICHELLE L. SCHREUR
U-21870**

1 Q. Please state your name and business address.

2 A. My name is Michelle L. Schreur and my business address is 7109 West Saginaw
3 Highway, Lansing, MI 48917.

4 Q. By whom are you employed and in what capacity?

5 A. I am employed by the Michigan Public Service Commission (MPSC or Commission) as
6 Manager of the Income Analysis Unit in the Revenue Requirements section of the
7 Regulated Energy Division.

8 Q. Please describe your educational background.

9 A. I graduated from Grand Rapids Community College in 2015 with an Associate Degree in
10 Business Administration. In 2017, I graduated from Grand Valley State University with a
11 Bachelor of Business Administration Degree in Accounting and Finance.

12 Q. Please describe your professional background with the MPSC.

13 A. I began my employment with the MPSC in September of 2017 as an auditor in the
14 Revenue Requirements section of the Regulated Energy Division. In that position my
15 responsibilities included, but were not limited to, performing rate case audits using the
16 financial and operating records of regulated utilities, applicable laws, regulations, and
17 Commission policies to determine the necessity of rate relief. In August 2022, I was
18 promoted to my current position as Manager of the Income Analysis Unit in the Revenue
19 Requirements Section of the Regulated Energy Division.

20 Q. Have you received ongoing training since joining the MPSC?

21 A. Yes. In September of 2017, I attended a Utility Business Model/Financial Valuation
22 Training hosted by Michigan State University Institute of Public Utilities (MSU IPU). In

**QUALIFICATIONS AND DIRECT TESTIMONY OF
MICHELLE L. SCHREUR
U-21870**

1 August of 2018, I attended a fundamental and intermediate Annual Regulatory Studies
2 Program hosted by MSU IPU.

3 Q. Have you previously sponsored testimony under that name Michelle L. Edelyn?

4 A. Yes.

5 Q. Have you previously sponsored testimony before the Michigan Public Service
6 Commission?

7 A. Yes. I have sponsored testimony in the following cases:

<u>Case Number</u>	<u>Company</u>	<u>Case Type</u>
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
U-21806	Consumers Energy Co.	Gas Rate Case
U-20860	DTE Electric Co.	Electric Rate Case

28 Q. What is the purpose of your testimony?

29 A. The purpose of my testimony is to present MPSC Staff's (Staff) overall Operations and
30 Maintenance (O&M) Expense Projection for the 12-month period ending April 30, 2027
31 (projected test year) in the instant Consumers Energy Company (Consumers or the

**QUALIFICATIONS AND DIRECT TESTIMONY OF
MICHELLE L. SCHREUR
U-21870**

1 Company) rate case.

2 Q. Are you sponsoring any exhibits in this proceeding?

3 A. Yes. I am sponsoring the following exhibits:

4 S-3 Schedule C-5: Projected Operations and Maintenance (O&M) Expense for the
5 Test Year Ending April 30, 2027

6 Q. Was this exhibit prepared by you or under your direction?

7 A. Yes.

8 **Projected O&M Expense**

9 Q. Please describe Exhibit S-3, Schedule C-5.

10 A. Exhibit S-3, Schedule C-5, presents Staff's O&M Expense Projection of \$785,113,000
11 for the 12-month period ending April 30, 2027, a decrease of \$19,839,000 from the total
12 Company's projection of \$804,952,000. Staff's projections were developed through the
13 categories listed in column (a). Column (c) presents the Company's Projection and
14 column (e) presents Staff's Projection, with the difference shown in column (d). The
15 differences in column (d) represent Staff adjustments and are supported by corresponding
16 Sources listed in column (b). A reconciliation by Expense, Amount, and Witness is
17 shown at the bottom of the exhibit.

18 Q. Does this conclude your testimony?

19 A. Yes.

1 MR. SONNEVELDT: Next, Your Honor, Staff moves
2 to bind in the direct testimony of Madison Todd. Mr.
3 Todd's direct testimony consists of a cover sheet and five
4 pages of questions and answers. He also sponsors Exhibit
5 S-6, Schedules F-2.0, F-2.1, F-3, and F-4, thereby, by my
6 notes, completing the entirety of Exhibit S-6.

7 JUDGE THOITS: Are there any objections to the
8 admission to this testimony or this exhibit?

9 Hearing none. The direct testimony of Madison
10 Todd is bound under the record and Exhibit S-6 as
11 admitted.

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STATE OF MICHIGAN
BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

Case No. U-21870

In the matter of the application of
CONSUMERS ENERGY COMPANY
for authority to increase its rates for
the generation and distribution of
electricity and for other relief.

QUALIFICATIONS AND DIRECT TESTIMONY OF

MADISON S. TODD

MICHIGAN PUBLIC SERVICE COMMISSION

September 30, 2025

**QUALIFICATIONS AND DIRECT TESTIMONY OF
MADISON S. TODD
U-21870**

1 Q. Please state your name, business address, and current position.

2 A. My name is Madison S. Todd. My business address is 7109 West Saginaw Hwy, Lansing
3 MI, 48917. I am currently employed by the Michigan Public Service Commission
4 (“MPSC” or “Commission”) as a Departmental Analyst in the Rates & Tariff Section of
5 the Regulated Energy Division.

6 Q. What are your preferred pronouns?

7 A. He/him/his.

8 Q. What is your educational background?

9 A. I received a B.A. in Public Administration and Public Policy from Michigan State
10 University in 2011 and an M.P.A. with a specialization in State and Local Government
11 Management from Central Michigan University in 2013.

12 Q. Have you attended any seminars or other training courses?

13 A. Yes. In August 2019, I completed both the Fundamental and Intermediate weeklong
14 courses at the Institute of Public Utilities’(IPU) Annual Regulatory Studies Program on
15 Michigan State University’s campus - often called “Camp NARUC.” In 2021, I
16 completed a course in advance cost of service study and rate design training also through
17 IPU. In 2022, I completed the following courses: EUCI rate design, IPU advanced
18 accounting, EUCI battery course, EUCI energy storage course. Additionally, in 2024 I
19 completed EUCI’s course Advanced Rate Design for Cost Effective tariffs.

20 Q. What are the responsibilities of your current position?

21 A. I participate in rate, tariff amendment, surcharge and special contract cases. I update the
22 electric and gas bill comparison spreadsheets for the MPSC website. Additionally, I

**QUALIFICATIONS AND DIRECT TESTIMONY OF
MADISON S. TODD
U-21870**

update the annual statistical reports, serve as the backup to the Commission's tariff specialist, and serve as my division's web coordinator. I also assist other MPSC Staff members ("Staff") with various assignments and casework.

Q. Have you participated in any utility cases before the MPSC?

A. Yes. I have participated in the following cases:

Case No.	Utility	Description
U-20476	Presque Isle Electric & Gas Cooperative	Weather Normalization
U-20479	SEMCO Energy Gas Company	Rate Design
U-20561	DTE Electric Company	Other Revenue
U-20642	DTE Gas Company	Rate Design
U-20929	DTE Electric Company	Low-Income
U-20940	DTE Gas Company	Rate Design
U-21097	Northern States Power Company	Other Revenue
U-21113	SEMCO Energy Gas Company	Special Contracts
U-21286	Upper Peninsula Power Company	Rate Design
U-21291	DTE Gas Company	Rate Design
U-21366	Michigan Gas Utilities Corporation	Rate Design
U-21555	Upper Peninsula Power Company	Rate Design
U-21565	Northern States Power Company	Rate Design
U-21936	SEMCO Energy Gas Company	Surcharge Revenue

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to provide Staff's positions on rate design and revenue.

Q. Are you including any exhibits with your testimony?

A. Yes, I am sponsoring the following Exhibits:

Exhibits:

Staff Exhibit S-6, Schedule F-2.0, "Staff Summary of Present and Proposed Revenues by Rate Schedule."

Staff Exhibit S-6, Schedule F-2.1, "Staff Calculation of Rate Design Targets."

**QUALIFICATIONS AND DIRECT TESTIMONY OF
MADISON S. TODD
U-21870**

1 Staff Exhibit S-6, Schedule F-3.0, “Staff Present and Proposed Revenue Detail.”

2 Staff Exhibit S-6, Schedule F-4.0, “Staff Comparison of Present and Proposed Monthly
3 Bills.”

4 **Revenue**

5 Q. What does Staff recommend for present revenue?

6 A. Staff recommends a present revenue of \$4,759,698,037 versus the Company’s
7 \$4,733,806,753. A higher present revenue decreases the revenue deficiency. Details of
8 Staff’s present and proposed revenues can be found on Staff Exhibit S-6, Schedule F-2.0.

9 Q. What accounts for Staff’s present revenue adjustment?

10 A. Staff’s forecast, supported by Staff witness Paul R. Ausum, increased sales for lighting,
11 primary and commercial secondary classes. For these reasons, Staff’s present revenue
12 increased by \$25,891,284. The PSCR revenue portion of the adjustment, sponsored by
13 Staff witness Laura Maio, is \$12,228,188, which requires an equal increase in PSCR
14 expense. This increase offsets the revenue deficiency and leads to an impact on total
15 present revenue of \$13,663,096.

16 **Rate Design**

17 Q. Did Staff make any changes to the Company’s proposed rate design?

18 A. Yes, Staff used the revenue requirements from Staff’s cost-of-service study (COSS) as a
19 basis for calculations in its rate design. Staff’s COSS is sponsored by Staff witness Mark
20 Pung. Additionally, Staff corrected an error that the Company found in their voltage level
21 calculation for class GSG-2 Standby-Service Production. Also, Staff reviewed the
22 proposed rates upon completion of Staff’s rate design and evaluated their consistency

**QUALIFICATIONS AND DIRECT TESTIMONY OF
MADISON S. TODD
U-21870**

1 with general principles of rate design such as stability, efficiency, and reasonability.

2 Q. Please describe Exhibit S-6, Schedule F-2.0.

3 A. Exhibit S-6, Schedule F-2.0 is a summary of revenues at both current and Staff's
4 proposed rates for each rate schedule and calculates the net nominal and percentage
5 changes.

6 Q. Please describe Exhibit S-6, Schedule F-2.1.

7 A. Staff Exhibit S-6, Schedule F-2.1 shows Staff's calculations of rate design targets by rate
8 class for production, transmission, and delivery revenue requirements.

9 Q. Please describe Exhibit S-6, Schedule F-3.0.

10 A. Exhibit S-6, Schedule F-3.0 is a detailed summary of Staff's proposed rates by rate
11 schedule.

12 Q. Please describe Exhibit S-6, Schedule F-4.0.

13 A. Exhibit S-6, Schedule F-4.0 calculates average bills for both current rates and Staff's
14 proposed rates by rate schedule at a range of usage levels and then calculates the
15 percentage change comparison between average bills for each rate schedule and usage
16 amount. The average rate at each usage level is also calculated.

17 **Summary**

18 Q. Please summarize your recommendations.

19 A. Staff recommends the Commission approve the following:

20 - Staff's present revenue recommendation.

21 - Staff's rate design, modified for any adjustments made by the Commission.

22 Q. Does this conclude your testimony?

**QUALIFICATIONS AND DIRECT TESTIMONY OF
MADISON S. TODD
U-21870**

1 A. Yes.

1 MR. SONNEVELDT: Next, Your Honor, Staff moves
2 to bin the direct testimony of Timothy G. Witt. Mr.
3 Witt's testimony consists of a cover sheet and seven pages
4 of questions and answers. He also sponsors Exhibit S-2,
5 Schedule B-1.

6 JUDGE THOITS: Is there any objection to the
7 admission to this testimony or this exhibit?

8 Hearing none. The direct testimony of Timothy
9 Witt is bound under the record in Exhibit S-2 is admitted.

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STATE OF MICHIGAN
BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

Case No. U-21870

In the matter of the Application of
CONSUMERS ENERGY COMPANY
for authority to increase its rates for the
generation and distribution of
electricity and for other relief.

QUALIFICATIONS AND DIRECT TESTIMONY OF

TIMOTHY G. WITT

MICHIGAN PUBLIC SERVICE COMMISSION

September 30, 2025

**QUALIFICATIONS AND DIRECT TESTIMONY OF
TIMOTHY G. WITT
U-21870**

1 Q. Please state your name and business address.

2 A. My name is Timothy G. Witt and my business address is 7109 West Saginaw
3 Highway, Lansing, MI 48917.

4 Q. By whom are you employed and in what capacity?

5 A. I am employed by the Michigan Public Service Commission (“MPSC” or “Commission”)
6 as an auditor in the Revenue Requirements Section of the Regulated Energy Division.

7 Q. Please briefly describe your educational background and other professional
8 qualifications.

9 A. I earned a Bachelor of Business Administration Degree in Accounting from Western
10 Michigan University in 2006. In August 2011, I completed the National Association of
11 Regulatory Utility Commissions (“NARUC”) Annual Regulatory Studies Program at
12 Michigan State University focusing primarily on telecommunications regulation.

13 Q. Please describe your professional background with the MPSC.

14 A. I began my employment with the MPSC in January of 2011 as an auditor in the Access
15 Restructuring Mechanism (“ARM”) Fund section of the Telecommunications Division.
16 In that position I was responsible for handling the day-to-day functions of the fund. In
17 May of 2019, I joined the Rate Base Unit of the Revenue Requirements Section in the
18 Regulated Energy Division as an auditor.

19 Q. Briefly discuss your involvement with the MPSC cases.

20 A. I have performed audit work in the following cases:

21	Case Number	Company	Case Type
22	U-20561	DTE Electric Co.	Electric Rate Case
23	U-20521	DTE Electric Co.	Demand Response

**QUALIFICATIONS AND DIRECT TESTIMONY OF
TIMOTHY G. WITT
U-21870**

1	U-20642	DTE Gas Co.	Gas Rate Case
2	U-20697	Consumers Energy Co.	Electric Rate Case
3	U-20794	Detroit Thermal LLC	Steam Rate Case
4	U-20963	Consumers Energy Co.	Electric Rate Case
5	U-21045	Alpena Power Company	Electric Rate Case
6	U-21148	Consumers Energy Co.	Gas Rate Case
7	U-21224	Consumers Energy Co.	Electric Rate Case
8	U-21286	Upper Peninsula Power Co.	Electric Rate Case
9	U-21308	Consumers Energy Co.	Gas Rate Case
10	U-21366	Michigan Gas Utilities Co.	Gas Rate Case
11	U-21461	Indiana Michigan Power Co.	Electric Rate Case
12	U-21488	Alpena Power Co.	Electric Rate Case
13	U-21490	Consumers Energy Co.	Gas Rate Case
14	U-21555	Upper Peninsula Power Co.	Electric Rate Case
15	U-21585	Consumers Energy Co.	Electric Rate Case
16	U-21806	DTE Gas Co.	Gas Rate Case
17	U-21860	DTE Electric Co.	Electric Rate Case

18 Q. Have you previously sponsored testimony before the Michigan Public Service
19 Commission?

20 A. Yes. I have sponsored testimony in the following cases:

21	Case Number	Company	Case Type
22	U-20521	DTE Electric Co.	Demand Response
23	U-20561	DTE Electric Co.	Electric Rate Case
24	U-20642	DTE Gas Co.	Gas Rate Case
25	U-20794	Detroit Thermal LLC	Steam Rate Case
26	U-20963	Consumers Energy Co.	Electric Rate Case
27	U-21045	Alpena Power Company	Electric Rate Case
28	U-21148	Consumers Energy Co.	Gas Rate Case
29	U-21224	Consumers Energy Co.	Electric Rate Case
30	U-21286	Upper Peninsula Power Co.	Electric Rate Case
31	U-21308	Consumers Energy Co.	Gas Rate Case
32	U-21389	Consumers Energy Co.	Electric Rate Case
33	U-21461	Indiana Michigan Power Co.	Electric Rate Case
34	U-21555	Upper Peninsula Power Co.	Electric Rate Case
35	U-21585	Consumers Energy Co.	Electric Rate Case
36	U-21806	DTE Gas Co.	Gas Rate Case
37	U-21860	DTE Electric Co.	Electric Rate Case

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**QUALIFICATIONS AND DIRECT TESTIMONY OF
TIMOTHY G. WITT
U-21870**

1 Q. What is the purpose of your testimony?

2 A. The purpose of my testimony is to present MPSC Staff's ("Staff") projected rate base for
3 the test period ending April 30, 2027 ("projected test year" or "test year") in the instant
4 Consumers Energy Company ("Consumers Energy" or the "Company") gas rate case.
5 Additionally, I will be supporting adjustments to the Company's projected depreciation
6 and amortization expense, and property tax expense. These adjustments are included on
7 Staff Exhibit S-3, Schedule C-1, sponsored by Staff witness Nichols.

8 Q. Are you sponsoring any exhibits in this proceeding?

9 A. Yes, I am sponsoring the following exhibits:

10 Exhibits:

11 S-2 Schedule B-1: Projected Rate Base for Test Year Ending 4/30/27.

12 Q. Was the exhibit prepared by you or under your direction?

13 A. Yes.

14 **RATE BASE**

15 Q. What is the total rate base being presented by Staff in the instant case for the projected
16 test year?

17 A. Referring to Staff Exhibit S-2, Schedule B-1, Line 78, Column (e), Staff presents a total
18 rate base of \$15,205,256,000. This is a decrease of \$162,262,000 from the Company's
19 \$15,367,518,000 projection presented on Exhibit A-12, Schedule B-1, Line 7, Column
20 (c), in its initial filing. Below my testimony will address the individual components
21 which result in Staff's \$162,262,000 reduction to the Company's file projected rate base.
22

**QUALIFICATIONS AND DIRECT TESTIMONY OF
TIMOTHY G. WITT
U-21870**

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 \$19,790,429,000. This is a decrease of \$168,318,000 from the Company's \$19,958,747,000 projection presented on Exhibit A-12, Schedule B-1, Line 1 Column (c), in its initial filing.

Q. Please explain the \$168,318,000 reduction.

A. The \$168,318,000 reduction 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.

FIGURE 1*		Total Cap Ex Adj.	Test Year Impacts From Historic and Projected CapEx Adjustments				
Staff Witness	Adjustment Category		Plant in Svc	Accum. Depr.	Rate Base	Depreciation	Property Tax
		Increase / (Decrease)	Increase / (Decrease)	Increase / (Decrease)	Increase / (Decrease)	Increase / (Decrease)	Increase / (Decrease)
Boutet	Distribution - Reliability	(37,823)	(28,400)	(777)	(27,623)	(847)	(379)
Durfee	Distribution - Reliability	(108,333)	(83,404)	(2,371)	(81,033)	(2,487)	(1,113)
Boutet	Distribution - Capacity	(20,704)	(10,977)	(193)	(10,784)	(327)	(147)
Boutet	Distribution - Asset Relocations	(26,340)	(19,592)	(603)	(18,989)	(584)	(262)
Durfee	Distribution - Asset Relocations	(258)	(221)	(7)	(214)	(7)	(3)
Durfee	Distribution - Demand Failures	(2,131)	(1,676)	(50)	(1,625)	(50)	(22)
Shi	Distribution - Reliability	(3,410)	(2,090)	(46)	(2,044)	(62)	(28)
Maio	Generation - Steam	(13,177)	(9,909)	(473)	(9,436)	(410)	(132)
Maio	Generation - Hydro	861	1,321	25	1,296	37	18
Maio	Generation - Other	(592)	(592)	(52)	(540)	(14)	(8)
Klocke	Information Technology - Customer	(4,148)	(3,903)	(1,178)	(2,724)	(781)	(52)
Duell	Information Technology - Electric	(88)	(59)	(7)	(52)	(12)	(1)
Zichi	Information Technology - IT/Digital Founda	(3,047)	(1,982)	(262)	(1,720)	(396)	(26)
Duell	Operations Support - Control Dispatch	(10,184)	(6,310)	(56)	(6,254)	(98)	(84)
Hansen	Operations Support - Emergent Repairs	(949)	(474)	(4)	(471)	(7)	(6)
Hansen	Operations Support - Other equipment	(98)	(49)	(1)	(48)	(3)	(1)
	TOTAL	(230,419)	(168,318)	(6,056)	(162,262)	(6,049)	(2,247)
*Source - WP-TGW-1							

**QUALIFICATIONS AND DIRECT TESTIMONY OF
TIMOTHY G. WITT
U-21870**

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 \$6,644,587,000. This is a decrease of \$6,056,000 from the Company's \$6,650,643,000 projection presented on Exhibit A-12, Schedule B-1, Line 2, Column (c), in its initial filing.

Q. Please explain the \$6,056,000 reduction.

A. The \$6,056,000 reduction 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 4 of my 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 7, Column (d), sponsored by Staff witness Nichols, to decrease the Company's test year projection by \$6,049,000.

Q. Please explain the \$6,049,000 reduction.

A. The \$6,049,000 reduction 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 4 of my testimony).

**QUALIFICATIONS AND DIRECT TESTIMONY OF
TIMOTHY G. WITT
U-21870**

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 8, Column (d) sponsored by Staff witness Nichols, to decrease the Company's test year projection by \$2,247,000.

Q. Please explain the \$2,247,000 reduction.

A. The \$2,247,000 reduction 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 4 of my testimony) multiplied by the Company's property tax rate of 1.3349387% from Company Exhibit A-180 (BJV-1).

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 \$15,205,256,000, Staff's \$6,049,000 reduction

**QUALIFICATIONS AND DIRECT TESTIMONY OF
TIMOTHY G. WITT
U-21870**

- 1 to depreciation expense, and Staff's \$2,247,000 reduction to the property tax expense.
- 2 Specifically, my testimony supports a \$162,262,000 reduction to the Company's
- 3 projected rate base, a reduction to total utility plant of \$168,318,000, a reduction to
- 4 depreciation reserve of \$6,056,000, a reduction to depreciation expense of \$6,049,000,
- 5 and a reduction to property tax expense of \$2,247,000.
- 6 Q. Does this conclude your testimony?
- 7 A. Yes

1 MR. SONNVELDT: Next, Staff would like to move
2 to bind in the rebuttal testimony of Elaina M.
3 Braunschweig. Ms. Braunschweig's test rebuttal testimony
4 consists of a cover sheet and four pages of questions and
5 answers. She sponsors no exhibits.

6 JUDGE THOITS: Are there any objections to the
7 admission of this testimony?

8 Hearing none. The rebuttal testimony of Elaina
9 Braunschweig is bound into the record.

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STATE OF MICHIGAN
BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

Case No. U-21870

In the matter of the application of
CONSUMERS ENERGY COMPANY
for authority to increase its rates for the
generation and distribution of electricity
and for other relief.

REBUTTAL TESTIMONY OF

ELAINA M. BRAUNSCHWEIG

MICHIGAN PUBLIC SERVICE COMMISSION

October 21, 2025

**REBUTTAL TESTIMONY OF
ELAINA M. BRAUNSCHWEIG
U-21870**

1 Q. Please state your name and business address.

2 A. My name is Elaina M. Braunschweig. Pronouns she/her. My business address is 7109
3 West Saginaw Hwy, Lansing, Michigan 48917.

4 Q. By whom are you employed and in what capacity?

5 A. I am employed by the Michigan Public Service Commission (MPSC or Commission) as a
6 Departmental Analyst for the Rates and Tariff Section of the Regulated Energy Division.

7 Q. Please describe your educational background.

8 A. In 2018, I completed my Bachelor of Arts dual-major in Economics & Management and
9 German with a minor in International Studies with honors from Albion College.

10 Q. What are your current responsibilities at the MPSC?

11 A. As an analyst, I participate in rate and tariff amendment cases under the direct
12 supervision of the Rates and Tariff manager. I am also responsible for coordinating tariff-
13 related *ex-parte* cases and the Rates and Tariff Section's connection to low-income
14 energy assistance and affordability. To that end, in July 2021, I began co-leading the
15 Affordability, Alignment, and Assistance subcommittee in the Commission's Energy
16 Affordability and Accessibility Collaborative and continue that to-date.

17 Q. Have you attended any seminars or other training courses relating to your current role?

18 A. Yes. In August 2021, I participated in Michigan State University's Institute of Public
19 Utilities Annual Regulatory Studies Program Fundamentals Course. In October 2021, I
20 attended Michigan State University's Institute of Public Utilities Advanced Cost
21 Allocation and Rate Design Course, and in February 2022, I attended EUCI's Electric
22 Utility Pricing Trends in Cost Recovery Course.

**REBUTTAL TESTIMONY OF
ELAINA M. BRAUNSCHWEIG
U-21870**

1 Q. Have you previously presented testimony or participated in utility cases before the
2 MPSC?

3 A. Yes, I have presented testimony or otherwise participated in the following cases:

4	<u>Case No.</u>	<u>Company</u>	<u>Subject/Type</u>
5	U-20650	Consumers Energy	Gas Rate Design/Low-Income
6	U-20757	Commission	Low-Income Covid Report
7	U-20907	UMERC	Budget Billing Revisions
8	U-20929	DTE Energy	PSP Pilot Proposal
9	U-21021	Consumers Energy	PIPP Pilot Proposal
10	U-21148	Consumers Energy	Gas Rate Design/Low-Income
11	U-20836	DTE Energy	Low-Income Credits
12	U-21286	UPPCO	Low-Income Credits
13	U-21308	Consumers Energy	Gas Rate Design/Low-Income
14	U-21461	Indiana Michigan Power	Rate Design/Low-Income
15	U-21490	Consumers Energy	Gas Low-Income Credits
16	U-21291	DTE Gas	Low-Income Credits
17	U-21534	DTE Energy	Low-Income Credits
18	U-21585	Consumers Energy	Energy Affordability
19	U-21806	Consumers Energy	Low-Income Credits
20	U-21860	DTE Energy	Low-Income Credits

21 Q. What is the purpose and structure of your rebuttal testimony?

22 A. The purpose of my rebuttal testimony is to present Staff's response to certain positions
23 taken by the Urban Core Collective (UCC) witnesses Sergio Cira-Reyes and Tabitha
24 Williams.

25 Q. Please summarize relevant recommendations from UCC witnesses Cira-Reyes and
26 Williams.

27 A. In direct testimony, UCC witnesses Cira-Reyes and Williams recommended the
28 Commission approve a percentage of income payment plan (PIPP).¹

¹ Direct Testimony of UCC witness Sergio Cira-Reyes, p. 46; Direct Testimony of UCC witness Tabitha Williams, p. 31.

**REBUTTAL TESTIMONY OF
ELAINA M. BRAUNSCHWEIG
U-21870**

1 Q. What evidence does Staff present in response to the UCC recommendations?

2 A. Staff cites the statute MCL 460.11(2), and its corresponding eligibility criteria outlined in
3 MCL 460.10t(6)(b).

4 Staff additionally cites the DTE Electric rate case order issued by the Commission in
5 MPSC Case No. U-21534, in which the Commission states: “Therefore, the Commission
6 finds that the LIA credit should be increased to \$50. However, the Commission finds that
7 after final decisions and recommendations are provided by the EAAC, the Commission
8 may continue to refine the LIA program in the future, including potentially changing the
9 amount of this credit.”² LIA stands for the low-income assistance credit. EAAC stands
10 for the Energy Affordability and Accessibility Collaborative. The Commission reaffirmed
11 its position in Consumers Electric’s rate case, MPSC Case No. U-21585, by disallowing
12 large-scale energy assistance reform as well in stating: “However, the Commission agrees
13 with the Staff that the instant rate case is not the appropriate forum for such policy
14 modifications. As already noted by the ALJ, the Commission is currently reviewing low-
15 income programs in numerous forums, including in the EAAC and EWR plan
16 proceedings.”³ EWR stands for energy waste reduction.

17 Q. How has Staff worked to fulfill the cited Commission orders?

18 A. During the pendency of this instant case, Staff filed its Energy Affordability Report in
19 MPSC Case No. U-20757 on 9/10/2025.

20 Q. Do UCC witnesses raise issues and make recommendations that overlap with content in

² MPSC Case No. U-21534, 1/23/25 Commission Order, p. 405.

³ MPSC Case No. U-21585, 3/21/25 Commission Order, p. 391.

**REBUTTAL TESTIMONY OF
ELAINA M. BRAUNSCHWEIG
U-21870**

1 MPSC Staff's Energy Affordability Report?

2 A. Yes, there are topics and recommendations in witness testimonies in the instant case that
3 could overlap, conflict, or agree with the MPSC Staff Energy Affordability Report.
4 Seeing as the Commission's last stated position directed energy assistance and
5 affordability reform to disseminate from that report/the EAAC, Staff recommends the
6 Commission take a consistent approach and align its decisions with the Staff report as it
7 addresses the intervenor recommendations in the instant case.

Summary

8
9 Q. Please summarize your positions and recommendations in your rebuttal testimony.

10 A. Staff provides notice of filing its report on energy affordability and PIPPs, as requested
11 by the Commission in MPSC Case No. U-21534. This report addresses many of the
12 issues raised in testimonies provided by intervening party witnesses and Staff
13 recommends the Commission align its decisions with the Staff report as it addresses the
14 intervenor recommendations in the instant case.

15 Q. Does this conclude your rebuttal testimony?

16 A. Yes, it does.

1 MR. SONNEVELDT: Finally, Your honor, Staff
2 would move to bind in one hearing room exhibit through
3 stipulation with the utility and non-objection of the
4 parties. The hearing room exhibit is uploaded to the
5 SharePoint folder and is marked as hearing room Exhibit S-
6 21.

7 JUDGE THOITS: Are there any objections to the
8 admission of this exhibit?

9 Hearing none. Exhibit S-21 as admitted.

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1 MR. SONNEVELDT: At this point, Your Honor, can
2 I -- can we go off the record for a minute so I can talk
3 to my fellow co-counsel?

4 JUDGE THOITS: Sure. We'll go off the record
5 for five minutes. Is that enough?

6 MR. SONNEVELDT: That's enough.

7 JUDGE THOITS: All right. We're off the record.
8 (Off the record at 10:47 a.m.)

9 (On the record at 10:48 a.m.)

10 JUDGE THOITS: I understand that that completes
11 the bind-in for all of the parties' witnesses. Is that
12 correct?

13 MR. SONNEVELDT: That is correct, Your Honor.

14 JUDGE THOITS: All right. Mr. Sonneveldt was
15 kind enough to remind me of Mr. Templeton expressing some
16 interest in admitting some hearing room exhibits. Mr.
17 Templeton, are you with us?

18 All right. We will adjourn for the morning.
19 We will reconvene at one o'clock, and in the interim, I
20 will reach out to Mr. Templeton and see if we can verify
21 where we are. Does anybody have anything else before we
22 go off the record?

23 All right. Thank you. Again, we will reconvene
24 at one o'clock. We're off the record.

25 (Off the record at 10:50 a.m.)

1 (On the record at 1:03 p.m.)

2 JUDGE THOITS: We're back on the record. Case
3 U-21870. We adjourned this morning after some additional
4 binding in of the testimony of various witnesses. It's my
5 understanding that we completed that process with respect
6 to everyone who appeared this morning, all the parties
7 that appeared.

8 It was also suggested that Urban Core Collective
9 may have had additional exhibits that they wish to move
10 the admission of. I communicated with Mr. Templeton by
11 email this morning, and he confirmed that Urban Core
12 Collective concluded the presentation of its case last
13 week. So, I believe that all parties have presented the
14 entirety of their cases at this point. And so, I think
15 we're going to conclude this hearing unless anyone has
16 anything else for us.

17 All right. Hearing none. The hearing in this
18 matter is completed. We are adjourned and off the record.

19
20 (The proceeding was adjourned at 1:06 p.m.)

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1 STATE OF MICHIGAN)

2)ss

3 COUNTY OF OAKLAND)

4 CERTIFICATION

5 I certify that this transcript, consisting of
6 sixty-five (65) pages, is a complete, true, and correct
7 record of the matter of Case No. U-21870, before Jonothan
8 Thoits, Administrative Law Judge with MOAHR, for the
9 Michigan Public Service Commission, Lansing, Michigan on
10 Thursday, November 10, 2025.

11 I also certify that I am not a relative of,
12 employee of, or an attorney for a party; nor am I
13 financially interested in the action.

14 
15 _____

16 Nina Danno, CER 16342

17 Notary Public, Oakland County, Michigan

18 My Commission Expires: 01/06/31

19
20 (Transcript continues on page 4617 of the confidential
21 record.)
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