May 23, 2025

Ms. Lisa Felice
Executive Secretary
Michigan Public Service Commission
7109 West Saginaw Highway
Post Office Box 30221
Lansing, MI 48909

Re: MPSC Case No. U-21806 – In the matter of the application of Consumers Energy Company for authority to increase its rates for the distribution of natural gas and for other relief.

Dear Ms. Felice:

Enclosed for electronic filing in the above-captioned case, please find the **Redacted Revised Testimony of Consumers Energy Company Witnesses Luther A. Bonner, Quentin A. Guinn, Michael P. Griffin, James P. Pnacek, and Lincoln D. Warriner**. The confidential Revised Testimony of Company witness Quentin A. Guinn will be filed under seal with the Executive Secretary.

This is a paperless filing and is therefore being filed only in PDF. Also included is a Proof of Service showing electronic service upon the parties.

Sincerely,

Digitally signed by Anne M. Uitvlugt
Date: 2025.05.23 12:02:46 -04'00'

Anne M. Uitvlugt
Phone: 517-788-2112
Email: anne.uitvlugt@cmsenergy.com

cc: Parties to Attachment 1 to the Proof of Service

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

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

REVISED REBUTTAL TESTIMONY

OF

LUTHER A. BONNER

ON BEHALF OF

CONSUMERS ENERGY COMPANY

May 2025

Q. Please state your name and business address.

A. My name is Luther A. Bonner, and my business address is 530 West Willow Road, Lansing, Michigan 48906.

Q. In what capacity are you employed?

A. I am employed as Senior Manager of Engineering Support for Consumers Energy Company ("Consumers Energy" or the "Company").

Q. What is your educational background?

A. I earned an Associates of Business Administration from Baker College in 2003. I also hold an associate certificate in Project Management from George Washington University.

Q. What have your job responsibilities entailed with Consumers Energy?

A. I began working for Consumers Energy in 2003 and have held positions of increasing responsibility over my 21 years with the Company. My roles have included Senior Manager Engineering Support, Manager Engineering Support, Senior Engineering Technical Analyst Lead, Senior Business Support Consultant III, Regional Project Coordination Manager, Customer Energy Specialist Principal Team Lead, Customer Energy Specialist Team Leader III, Senior Customer Energy Specialist, Customer Energy Specialist III, Customer Energy Specialist II, and Customer Energy Specialist I. From 2003 through 2014 prior to my leadership roles, my responsibilities included designing electric and natural gas systems, planning customer requested projects, project management, facilitating easements, permitting, and generating costs estimates. These tasks were undertaken in the service of providing natural gas and electric services to residential customers, new developments, commercial & industrial customers, and municipal electric generating facilities from natural gas. From 2014 through 2019, my

experience was in leading teams that designed, planned, and managed those various types of projects. Since 2019, my responsibilities have included developing processes and procedures used across the work management stream, and developing technology platforms for project management.

Q. Please summarize your experience with Rule C8. Customer Attachment Tariff.

A. Since the beginning of my career with the Company in 2003, I have followed and administered Rule C.8, Customer Attachment Tarriff, which is the regulatory requirement for this process. My experience includes running customer requested scenarios through the model, and reviewing projects modeled by others to ensure compliance. This modeling involved the determination of any revenue deficiency and assessing the amount that a customer requesting service under Rule C8 needed to pay as an upfront contribution in aid of construction based on the model's output.

Q. Please summarize your experience with the use of, administration, and development of the Gas Engineering Model that is used to calculate gas line extensions and service contributions for new connecting customers, which is part of the New Business Mains, Services, and Meters Program and follows the Customer Attachment Tariff, Rule C.8.

A. From 2003 through 2014, part of my responsibilities involved the use of the original Gas Engineering Model to calculate estimates for the natural gas projects I was assigned to as a Customer Energy Specialist for the Company in support of customers who requested service, line extensions, and/or new developments and generation facilities. During 2014 through 2022, my responsibilities included reviewing and approving cost estimates to validate compliance with RuleC.8 Customer Attachment Tariff and identifying ways to improve the technology used. In 2022, I was assigned overall responsibility of the Gas

Engineering Model. During 2022, my team and I developed the most current version of the model using a web-based application.

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

A. No, I have not.

Q. Are you sponsoring any exhibits?

A. Yes. I am sponsoring the following exhibits:

Exhibit A-119 (LAB-1)	Footage Allowance & Excess Service Charge Trends 2003-2025;
Exhibit A-120 (LAB-2)	Excess Service Cost Formula;
Exhibit A-121 (LAB-3)	CE Gas Consumption Jan2020-Jan2025;
Exhibit A-122 (LAB-4)	Customer Gas Service Retirement Trend;
Exhibit A-123 (LAB-5)	MPSC-MNS CAP Conversion Update Sep 2022;
Exhibit A-124 (LAB-6)	Average Vintage Year Gas Retirements;
Exhibit A-125 (LAB-7)	Customer Gas Alteration Trend; and
Exhibit A-126 (LAB-8)	MPSC CAP Pricing Update March 2023.

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

A. Yes.

Q. What is the purpose of your rebuttal testimony?

A. The purpose of my testimony is to rebut certain assertions and recommendations made by Michigan Environmental Council and Sierra Club (collectively "MEC") witness Alice Napoleon regarding Consumers Energy's Line Extension Policy. My testimony specifically rebuts claims that (1) the Company is providing increasing footage allowances that are subsidized by existing customers, (2) the Company's model uses outdated data and assumptions to calculate customers contributions, (3) the Company overstates the period

of time that customers will receive natural gas service in the modeling of customer contributions, and (4) the Company has not fulfilled its requirements resulting from a settlement agreement in a prior gas rate case.

I. MEC WITNESS NAPOLEON

Q. On page 20, lines 5 through 9, of her direct testimony, MEC witness Napolean discussed the Company's line footage allowance and claimed that longer footage allowances result in lower costs for new customers and greater costs spread across ratepayers. Do you agree with this assessment?

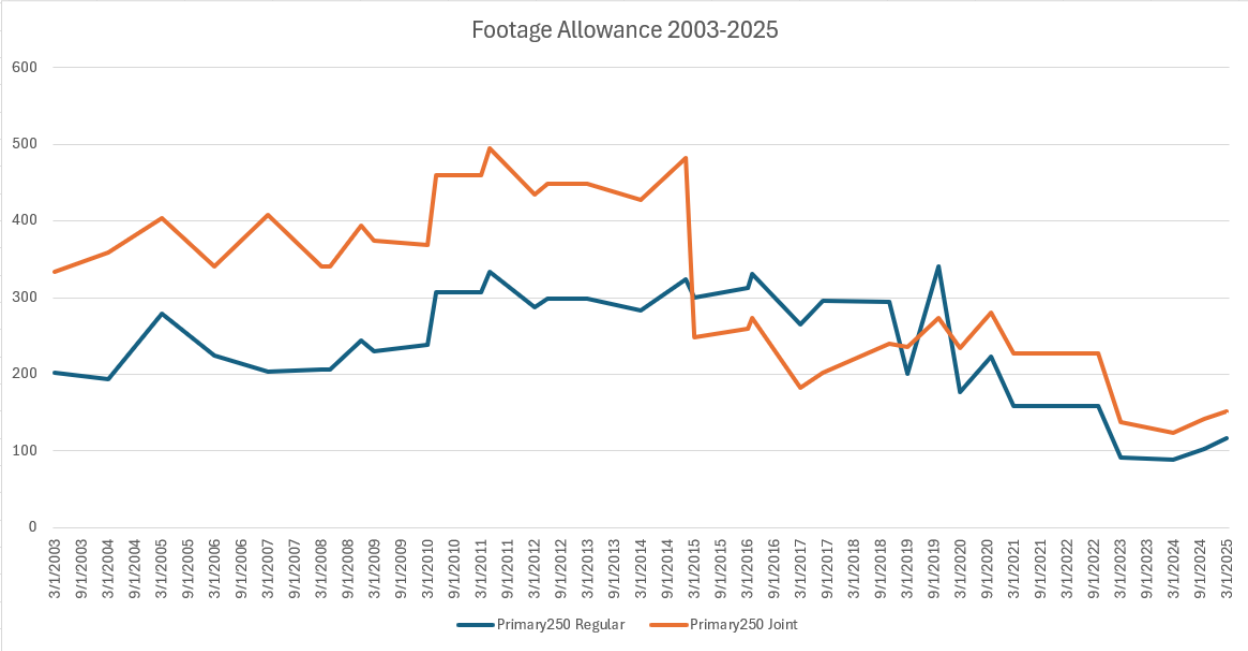
A. No. While I can confirm that the footage allowances of 88 feet (for gas only service) and 124 feet (for joint gas and electric service) that were implemented on March 1, 2024 increased to 117 feet and 152 feet, respectively, on March 1, 2025, the Company has significantly decreased its footage allowances since 2003 thereby increasing upfront costs for connecting services and reducing costs that are being recovered through the new service revenue included in the 20-year modeling period. In 2024, the footage allowance was at its lowest point in the past two decades. This is demonstrated in Exhibit A-119 (LAB-1).

From 2003 through 2024, the footage allowance decreased for various classifications of metering. For example, for the most common services with 250 class gas meters (for gas only service), there has been a footage allowance decrease of 42.08% (202 ft to 117 ft) from 2003 to its current value and a 65.69% (341 ft to 117 ft) decrease from its highest point in October 2019. For the most common services with 250 class meters (with joint gas/electric service), there has been a footage allowance decrease of 54.35% (333 ft to 117 ft) to its current value and a 69.29% (495 ft to 117 ft) decrease from its highest point in May 2011.

Some metering classifications, such as a 3M meter with joint gas/electric service, no longer offer footage allowances based on average revenue. Instead, a customer specific revenue deficiency amount using the net present value ("NPV") calculation is performed to ensure that the Company will recover its costs using the appropriate amount of revenue over the first 20 years.

In addition, the recent slight increases in footage allowances also reflect the Company's ongoing efforts to reduce its actual unit costs, which results in lower plant in service cost amounts input to the model calculations. The plant in service cost is one of the inputs to the model that influences the NPV calculation. The Company uses the model to determine the amount of footage allowance that results in a model calculation of NPV that is greater than $0. Reductions in service installations costs ~~would~~ could cause the footage allowance to increase (based on the previous three years of actual costs incurred).

For example, the most current model update estimates that the Company will recover 100% of the annual revenue requirements from the new service attachment of a 117-foot gas only service based on average annual consumption of 94 mcf over 20 years. In this 117-foot service scenario, the NPV is $5.65. In that scenario, there is no calculated revenue deficiency to recover upfront costs from this attaching service.



The Company has continued to make necessary adjustments to the footage allowances since 2003 to ensure that new service revenues will recover the costs of installing new services as required by Rule C.8.

Q. On page 20, line 11, through page 21, line 2, of her direct testimony, Ms. Napoleon asserts that residential customers who exceed the footage allowance are responsible for a flat $200 revenue deficiency charge, an excess footage charge for gas-only connections of $21.26 per foot beyond the footage allowance ($17.28 for joint gas and electric hookups), and a connection fee and direct charges for things such as permitting and inspections. Is this accurate?

A. No. Customers with footage less than the footage allowance will pay a $200 connection fee and any direct charges such as permitting and inspections. Customers that exceed the footage allowance will pay a $200 connection fee, as well as any excess footage charges (or revenue deficiency) and any other direct charges. For example, a customer requesting service that is 55 feet long and requires work in a municipal road right-of-way with a permit

fee of $320 would be responsible for a $200 connection fee and the permit fee of $320, totaling $520. A customer requesting service of 150 feet for gas only, with the same permit costs, would be responsible for a $200 connection fee, an excess service fee of $701.58 (150 feet - 117 feet = 33 feet x $21.26 = $701.58), and a permit fee of $320, totaling $1,221.58.

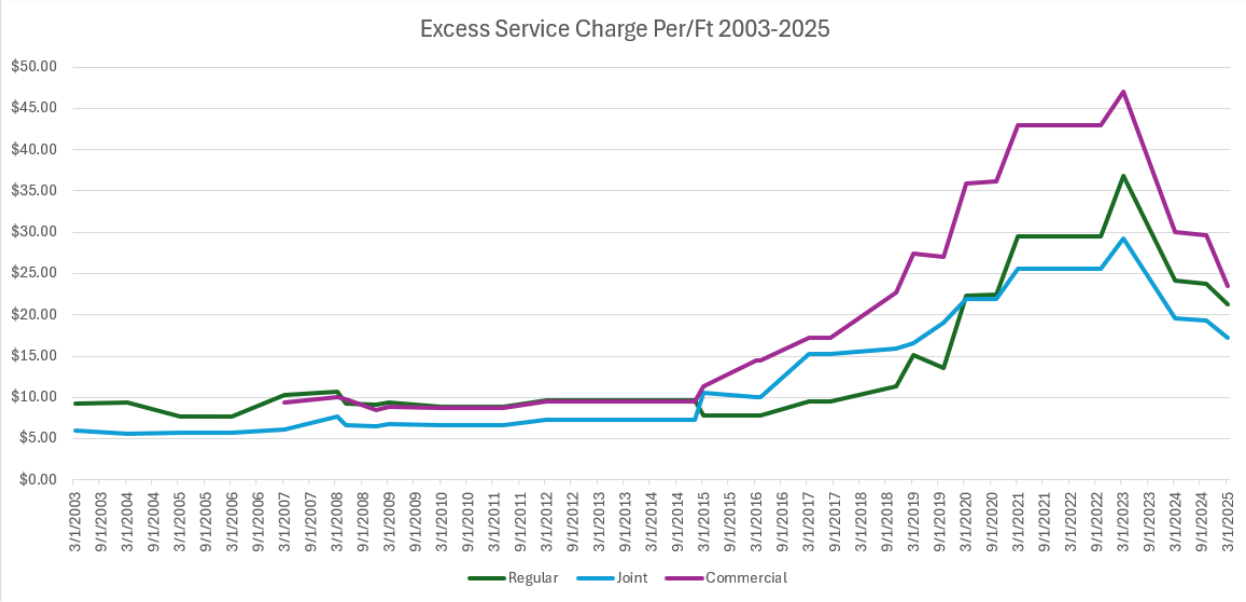
Q. On page 23, line 9, of her direct testimony, Ms. Napoleon indicates that it is not clear how the $200 flat charge for residential customers was determined and what it covers. Can you explain the Company's $200 connection fee?

A. The $200 connection fee is outlined in the Company's tariff and is separate from the revenue deficiency calculation. Every connecting customer is required to pay this direct connection fee per the Rule C.8 Customer Attachment Tariff.

Q. On page 23, lines 10 through 19 of her direct testimony, MEC witness Napoleon claims it is unclear what data Consumers used to produce these calculations, how frequently the Company updates excess footage charges, and why Consumers Energy decided to switch to a fixed model in the first place. Can you clarify the excess service charge calculation, how frequently they are updated, and why the Company uses a fixed model?

A. Yes, the calculation used to determine the excess service charge is (NetPresentValueProjectCost at X Feet - NetPresentValueProjectCost at Y Feet) / (X-Y) as referenced in Exhibit A-120 (LAB-2) to show how the $21.26 per ft charge was determined. The Company updates the excess footage charges at a minimum annually, the exception to this was during Covid where the Company opted not to update costs to support the building industry during those unprecedented times. In 2023, the excess service charge

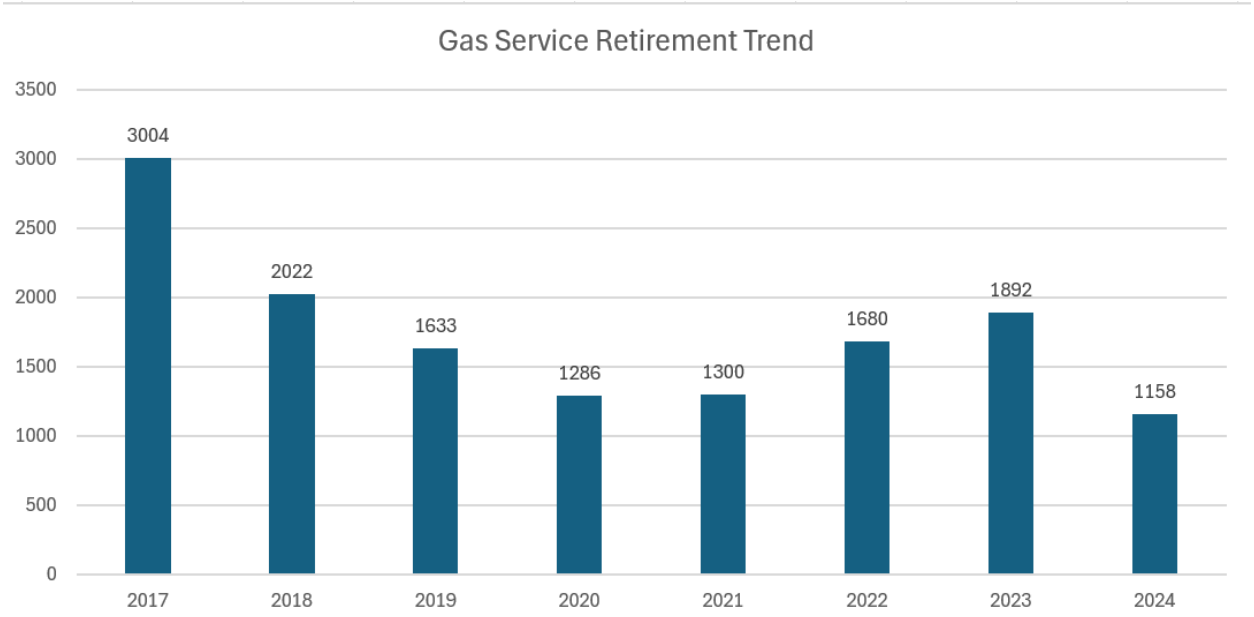
was at its highest point in the past two decades, as referenced in Exhibit A-119 (LAB-1). The Company uses a fixed model of footage allowance and excess footage charge to simplify the NPV calculation for customers, builders, and internal employees calculating invoices. The long-range trends of footage allowances and excess footage charges indicate that the Company is increasing costs for the customers requesting service and reducing the costs that are estimated to be recovered from the expected incremental revenue over 20 years. The chart below demonstrates the trend of excess footage charges from 2003 through 2025 as referenced in Exhibit A-119 (LAB-1).



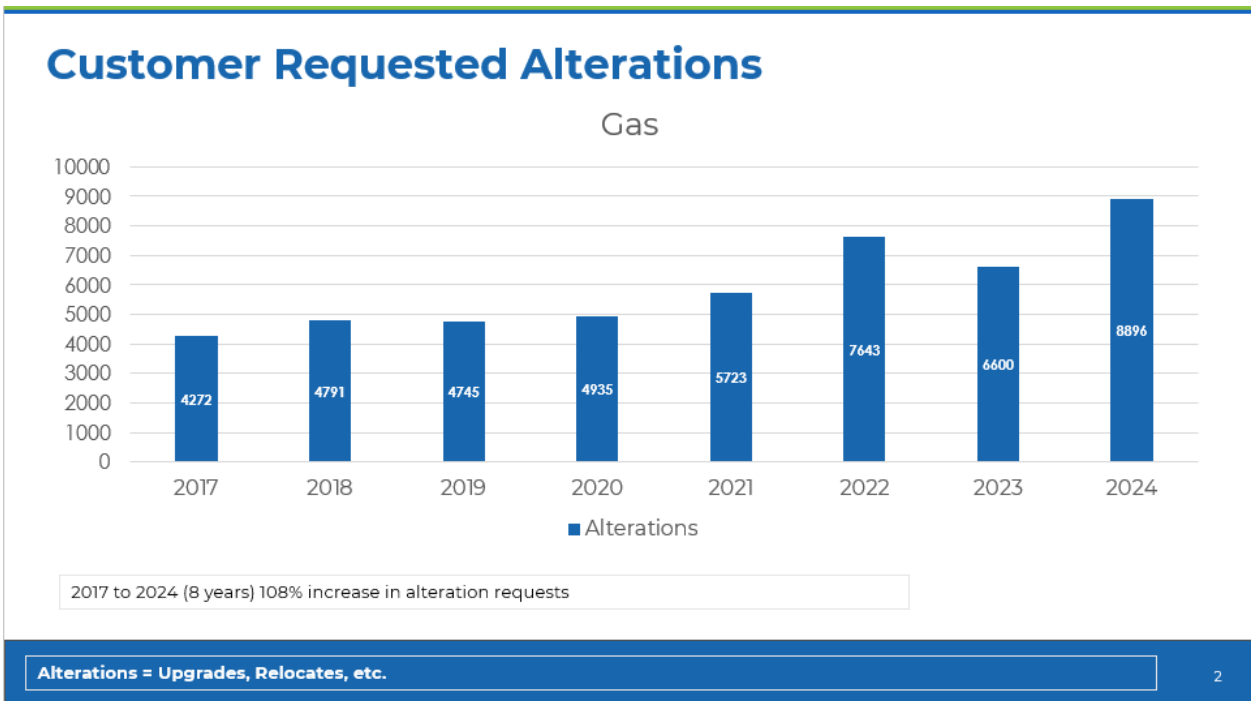
Annually the Company uses the model to determine what the footage allowance should be based on the previous three years of historical service installation cost and customer usage data. The calculated footage allowance is the point where the Company expects to recover all its service installation revenue requirements from the attaching customer over the 20-year period modeled per Rule C.8 Customer Attachment Tariff.

Q. On page 24, lines 1 through 8, of her direct testimony, Ms. Napoleon discusses calculating the revenue deficiency charge for non-residential customers and indicates that the Company takes into account equipment specifications, load diversification, and annual usage patterns to calculate a constant level of new customer sales, and the Company assumes the customer will remain connected to the gas system for 20 years. Could you share how the model accounts for non-residential revenue and the volume of service retirements?

A. The Company designs the natural gas distribution system for a minimum life span of 50 years, the sizing of the services and meters that attach to the distribution system are sized based on the current equipment specifications to be attached to the service, the load is diversified if deemed necessary based on those specifications and the Company accounts for the annual usage patterns provided by the customer for revenue that is accounted for in the NPV calculations. The Company does assume that the service will remain active for a minimum of 20 years in that calculation and the revenue received will remain constant. This assumption is based on the fact that the Company has only received requests from customers to retire on average 1463 services annually over the past five years as referenced in Exhibit A-122 (LAB-4) and the average lifespan of retired services over the past five years has been 43 years based on the vintage year the services were installed when retired as shown in Exhibit A-124 (LAB-6).



The Company also has received 8,896 gas service alteration requests in 2024; these requests are to either relocate the service or upgrade the service due to load increases. This is a 108% increase from the 4,272 alteration requests received in 2017, and the Company has experienced consistent increase in alteration requests year over year as shown in Exhibit A-125 (LAB-7). This is a clear indication that customers continue to utilize natural gas in the state of Michigan and request to utilize more natural gas even though there are alternative options available.



Q. On page 24, lines 10 through 12, of her direct testimony, Ms. Napoleon states that Consumers Energy has not provided the model, despite the terms of the Case No. U-21148 settlement which called for Consumers Energy to transition to a new model that was transparent and capable of being shared with stakeholders by the end of 2022. Did the Company meet the terms of the Case No. U-21148 settlement by transitioning to a new model that is transparent and capable of being shared?

A. Yes. The new model was built and implemented to be used to determine the annual costs on March 1, 2023. During the development of the model the Company met with MNSC and MPSC Staff to review the assumptions, the changes, and the impacts to the customers with the proposed assumption changes, referenced in Exhibits A-123 (LAB-5) and A-126 (LAB-8).

Q. Is the new model more transparent?

A. Yes. The transition to this new model was driven by several key factors:

1. **Age and Outdated Software**: The previous model was over 20 years old, and the software it was built on was outdated. This made it difficult to maintain and enhance the model.

2. **Technological Advancements**: The new .Net application allows for continuous enhancements as technology evolves, ensuring the model remains up-to-date and efficient.

3. **Transparency and Usability**: The new model is more transparent and is built on a software platform commonly used by Project Managers. This improves accessibility and usability.

4. **Updated Assumptions**: During the transition to the current model, key assumptions within the model were reviewed and updated. The new model enables annual updates to these assumptions, ensuring its accuracy and relevance.

The current model is more robust, transparent, user-friendly, and better meets the needs of the Company's team and stakeholders by providing more transparency in the calculations. For example: The most current model shows a view with a summary of the calculations as referenced Exhibit A-120 (LAB-2) The model is also built on a platform so the Company can create necessary reports or data extractions for its team and stakeholders, while no reporting or data extraction methods have been built at this time it now has that capability that the original model did not.

Q. How is the new model capable of being shared with stakeholders?

A. Yes. The model is shareable, but with certain limitations. The Company can bring external parties into its offices to demonstrate how the model works. However, since it is built on the internal network, it cannot provide external access due to security concerns.

The new model is designed to offer a more transparent view of the inputs, outputs, and calculations when shared internally. Consumers Energy has offered to arrange a meeting, invite the stakeholders, and walk them through the model, including its assumptions, calculations, and the inputs and outputs.

Q. On page 26, lines 14 through 16, of her direct testimony, Ms. Napoleon states the Company is likely using outdated assumptions for household gas consumption. Does the Company's customer contribution model use outdated assumptions for household gas consumption?

A. No, the assumptions within the model are updated annually and the average household consumption used is a rolling three-year historical average for all residential households and all residential multi-units (apartments, condos) using full heating seasons (Jul through Jun is an annual total), as shown in Exhibit A-121 (LAB-3).

Q. On page 26, lines 16 through 17, of her direct testimony, Ms. Napoleon states that there is significant risk associated with the Company's decision to subsidize new customer connections. Does the Company agree with this assertion that new connections are subsidized by other customers?

A. No. The primary objective and design of the program is to enable the expansion of cleaner, safer, more reliable, and more affordable gas utilities without requiring existing customers to subsidize these expansions. In this program, the costs of installing the necessary equipment for expansions are charged to new customers. These costs are balanced by the revenue generated by the newly attached customers over a period of 20 years. The risk of subsidization only exists if the new service is retired prematurely or the Company does not receive the forecasted revenue over the course of the next 20 years, as referenced in Exhibit A-121 (LAB-3). The volume of natural gas services is not declining, and the customers who moved in to utilize the attached services is stable (reference gas consumption).

Q. Should the Commission adopt the recommendations of Ms. Napoleon?

A. No, for the reasons stated above in my testimony, the Company believes the line extension policy is reasonable. However, if the Commission is interested in examining the Company's line extension policy, this should be done across all utilities through a work group. Using the same model across all utilities will ensure consistency across the industry.

Q. Does this conclude your rebuttal testimony?

A. Yes.

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

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

REDACTED

REBUTTAL TESTIMONY

OF

QUENTIN A. GUINN

ON BEHALF OF

CONSUMERS ENERGY COMPANY

May 2025

Q. Please state your name and business address.

A. My name is Quentin A. Guinn, and my business address is One Energy Plaza, Jackson, Michigan 49201.

Q. Are you the same Quentin A. Guinn who previously filed direct testimony in this proceeding?

A. Yes. I am also adopting the direct testimony and exhibits of Consumers Energy Company ("Consumers Energy" or the "Company") Company witness Corey E. Ballinger.

Q. What is the purpose of your rebuttal testimony?

A. The purpose of my rebuttal testimony is to address Attorney General Dana Nessel ("Attorney General") witness Sebastian Coppola's recommendation that the Michigan Public Service Commission ("MPSC" or the "Commission") remove Fleet Services forecasted capital expenditures of $1,202,000 for the 10 months ending October 2025 and $4,809,000 for the 12 months ending October 2026 for Fleet Vehicle Capital Replacement and Fleet Vehicle Electrification. I will also address Citizens Utility Board of Michigan's ("CUB") witness Joshua W. Denzler's recommendations that: (i) the Commission remove Fleet Services forecasted capital expenditures of $3,390,000 for the 22 months ending October 31, 2025 and $2,580,000 for the 12 months ending October 31, 2026 for Fleet Vehicle Capital Replacement Spend; (ii) the Commission reduce Fleet Services forecasted Operating and Maintenance ("O&M") expenses by [redacted] for the 12 months ending October 31, 2026 for Fleet Responsibility costs; (iii) the Commission order the Company to conduct a more specific study as to the expected savings of electrifying its fleet assets, by asset type (e.g., light duty car, pickup, van, heavy-duty, etc.) and provide the study in its next gas rate case with results incorporated into future requested cost recovery; (iv) the

Commission reduce Fleet Responsibility costs by $15,008,000 in 2025 and $15,008,000 in 2026; (v) the Commission order the Company to provide historical and projected fleet responsibility costs by capital and O&M, with more detailed information on the types of work these dollars support and the value received for these expenditures, by cost category and business unit for future rate cases; (vi) the Commission order the Company to prepare a more detailed analysis of its vehicle idling; (vii) the Commission remove Facility Operations forecasted capital expenditures of $14,937,000 for the 22 months ending October 31, 2025 for the Lansing Service Center Project; (viii) the Commission remove Facility Operations forecasted capital expenditures of $7,199,000 for the 12 months ending October 31, 2026 for the Lansing Service Center Project; (ix) the Commission remove Facility Operations forecasted capital expenditures of $114,000 for the 22 months ending October 31, 2025 for the Hastings Service Center Project; (x) the Commission remove Facility Operations forecasted capital expenditures of $4,380,000 for the 22 months ending October 31, 2025 for the Kalamazoo Service Center Project; and (xi) the Commission remove Facility Operations forecasted capital expenditures of $616,000 for the 12 months ending October 31, 2026 for the Kalamazoo Service Center Project.

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

A. No.

Q. Does the Company agree with Attorney General witness Coppola's recommendation on page 99 of his direct testimony that the Commission remove Fleet Services forecasted capital expenditures of $1,202,000 for the 10 months ending October 2025 and $4,809,000 for the 12 months ending October 2026 for Fleet Vehicle Capital Replacement and Fleet Vehicle Electrification?

A. No. Mr. Coppola's proposed reduction is based on an average cost per vehicle in 2024, inflating that cost by inflation factors for 2025 and 2026, and multiplying the resulting average cost by the number of vehicles planned to be purchased in those years. The Company does not purchase the same combination of vehicles each year. Therefore, the average cost per vehicle in the Company's Vehicle Replacement Plan may vary considerably from year to year, and the Company's projected unit costs are based on current manufacturer pricing. The Company's total Fleet Vehicle Capital Replacement Cost is the relevant metric for gauging year-over-year growth in capital spend. For the gas Fleet Vehicle Capital Replacement expenditures, the 2024 projected spend is $9.687 million and the 2025 projected spend is $9.919 million, a 2.4% increase.

Q. Does the Company agree with CUB witness Denzler's recommendation on page 19 of his direct testimony that the Commission remove Fleet Services forecasted capital expenditures of $3,390,000 for the 22 months ending October 31, 2025 and $2,580,000 for the 12 months ending October 31, 2026 for Fleet Vehicle Capital Replacement Spend?

A. No. Mr. Denzler recommended a 20% reduction in these expenditures based on his argument that the Company did not demonstrate the reliability of the Blended Factor model in making vehicle replacement decisions. First, as outlined on pages 8 through 12 of

Company witness Ballinger's direct testimony, the Blended Factor is only one of multiple quantitative and qualitative factors used to make vehicle replacement plan decisions. The efficacy of the Company's replacement plan decision making does not rest solely on the Blended Factor. Second, on page 18 of his direct testimony, Mr. Denzler cites a few instances in which the Company's Blended Factor model failed to accurately predict vehicle failure. As noted on page 12 of Company witness Ballinger's direct testimony, there are over 7,200 units in the Company's vehicle fleet. Therefore, the failure of the Blended Factor to accurately predict a few vehicle failures in this portfolio of over 7,200 assets during the course of several years does not statistically disprove the reliability of the Blended Factor model. Third, Mr. Denzler does not provide any calculation or explanation as to why a 20% disallowance is appropriate for projecting vehicle replacement costs as a result of Mr. Denzler's concerns with the use of the Blended Factor. Finally, the Company has included express reference to the Blended Factor in electric and gas rate case testimony for Fleet Services since the Commission's order issued in Case No. U-20963 in December 2021. During this nearly four-year period, the Commission's orders have not questioned the reliability of the Company's Blended Factor model.

Q. Does the Company agree with CUB witness Denzler's recommendation on page 21 of his direct testimony that the Commission reduce for Fleet Services forecasted O&M expenses of [redacted] for the 12 months ending October 31, 2026 for Fleet Responsibility expense because this total represents estimated fuel and maintenance savings from electric vehicles ("EVs") in the Company's fleet?

A. No. First, Mr. Denzler derived the O&M estimate from an analysis outlined on pages 20 and 21 of his direct testimony. Mr. Denzler's figure, however, is still an estimate based on

estimated savings across the major categories of passenger EVs owned by the Company. In response to discovery request U21806-AG-CE-0229, the Company indicated that it "has not yet incorporated specific fuel, maintenance and other savings assumptions into its budget projections for the replacement of an ICE [internal combustion engine] vehicle with an EV. Deployment of the Test Year units proposed in this case will provide empirical data needed to establish accurate assumptions about fuel, maintenance and other savings to be realized upon replacing ICE vehicles with EVs." Thus, it is premature to include these estimated savings in the projections in this case. Finally, it would be incorrect to assume that these types of savings would be entirely O&M. Fleet Responsibility costs include both an O&M and capital component, estimated in total at approximately ~~75~~67% capital and ~~25~~33% O&M based on historical actuals.

Q. How do you respond to CUB witness Denzler's recommendation on page 21 of his direct testimony that the Company conduct a more specific study as to the expected savings of electrifying its fleet assets?

A. The Company agrees to provide more specific information regarding expected savings from electrifying its fleet assets in future cases.

Q. Does the Company agree with CUB witness Denzler's recommendation on page 23 of his direct testimony that the Commission remove forecasted Fleet Responsibility costs of $15,008,000 in 2025 and $15,008,000 in 2026?

A. No. First, as noted on pages 6 and 7 of Company witness Ballinger's direct testimony, Fleet Responsibility costs are incurred to maintain the Company's vehicle fleet. Exhibit A-27 (CEB-2) includes annual historical Fleet Responsibility costs from 2016 through 2023. The amounts in Exhibit A-27 (CEB-2) represent actual Fleet Responsibility costs

and during this eight-year period the Commission never determined that these expenses are not reasonable or prudent. Second, Mr. Denzler notes that the Company is estimating approximately $75 million in Fleet Responsibility costs in 2025 and 2026. Given that actual Fleet Responsibility costs were $86.7 million in 2022 and $80 million in 2023 as shown in Exhibit A-27 (CEB-2), it would not be reasonable to reduce these expected costs by 20% of $75 million in 2025 and 2026. In addition, as discussed above, Fleet Responsibility costs include both an O&M and capital component, estimated in total at approximately ~~75~~67% capital and ~~25~~33% O&M. If the Commission adopted a disallowance of Fleet Responsibility costs, which it should not, the disallowance should be ~~75~~67% capital and ~~25~~33% O&M.

Q. Does the Company agree with CUB witness Denzler's recommendation on page 23 of his direct testimony that the Company provide historical and projected fleet responsibility costs by capital and O&M, with more detailed information on the types of work these dollars support and the value received for these expenditures, by cost category and business unit in future rate cases?

A. The Company agrees to provide the additional requested detail regarding Fleet Responsibility costs in future cases.

Q. Does the Company agree with CUB witness Denzler's recommendation on pages 26 and 27 of his direct testimony that the Company prepare a more detailed analysis of its vehicle idling?

A. The Company agrees to work on performing such an analysis.

Q. Does the Company agree with CUB witness Denzler's recommendation on pages 29 and 30 of his direct testimony that the Commission remove Facility Operations forecasted capital expenditures of $14,937,000 for the 22 months ending October 31, 2025 for the Lansing Service Center Project?

A. The Company disagrees with a portion of Mr. Denzler's recommendation. As outlined in response to discovery request U21806-AG-CE-0652, the Company's capital expenditures for the Lansing Service Center Project totaled $1,817,000 for the 12 months ended December 31, 2024. The Company's actual capital expenditures totaling $1,817,000 for the Lansing Service Center for the 12 months ended December 31, 2024 should be approved because they have actually been spent on the project. Based on the Commission's determination in Case No. U-21585, the Company will not oppose removal of the remaining forecasted capital expenditures of $13,120,000 ($1,817,000 less than Mr. Denzler's recommended $14,937,000) for the 22 months ending October 31, 2025 for the Lansing Service Center Project. The Company will present post-2024 expenditures for approval in a future rate case.

Q. Does the Company agree with CUB witness Denzler's recommendation on pages 29 and 30 of his direct testimony that the Commission remove Facility Operations forecasted capital expenditures of $7,199,000 for the 12 months ending October 31, 2026 for the Lansing Service Center Project?

A. Based on the Commission's Order in Case No. U-21585, the Company will not oppose this recommendation. The Company will present these expenditures for approval in a future rate case.

Q. Does the Company agree with CUB witness Denzler's recommendation on page 31 of his direct testimony that the Commission remove Facility Operations forecasted capital expenditures of $114,000 for the 22 months ending October 31, 2025 for the Hastings Service Center Project?

A. No. The Company disagrees with a portion of this recommendation. As outlined in my response to discovery request U21806-AG-CE-0652, the Company's capital expenditures for the Hastings Service Center Project totaled $95,000 for the 12 months ended December 31, 2024. The Company's capital expenditures totaling $95,000 for the Hastings Service Center Project for the 12 months ended December 31, 2024 should be approved because they have actually been spent on the project. Based on the Commission's determination in Case No. U-21585, the Company will not oppose removal of the remaining forecasted capital expenditures of $19,000 ($95,000 less than Mr. Denzler's recommended $114,000) for the 22 months ending October 31, 2025 for the Hastings Service Center Project. The Company will present post-2024 expenditures for approval in a future rate case.

Q. Does the Company agree with CUB witness Denzler's recommendation on page 32 of his direct testimony that the Commission remove Facility Operations forecasted capital expenditures of $4,380,000 for the 22 months ending October 31, 2025 and $616,000 in the test year for the Kalamazoo Service Center Project?

A. No. Mr. Denzler's argument that the project is being overbuilt by 40% is incorrect. At page 31 of his direct testimony, Mr. Denzler points to the Company's statement that the renovation will "incorporate and allow for up to 40% future growth opportunities" for his contention that the facility is being overbuilt by 40%. The Company is renovating its

existing Kalamazoo Service Center. As outlined on pages 29 and 30 of my direct testimony in this case, the Company did not construct or add space to the existing facility as part of this renovation. Rather, the footprint of the existing Kalamazoo Service Center is unchanged with renovations being done to the facility as is. While the Company could reduce the size of the facility as part of this renovation by demolishing a portion of the building, demolition of part of the building would add considerably to the cost of this project. It is far more cost effective to simply utilize existing space as is.

Q. Does this conclude your rebuttal testimony?

A. Yes.

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

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

REVISED DIRECT TESTIMONY

OF

MICHAEL P. GRIFFIN

ON BEHALF OF

CONSUMERS ENERGY COMPANY

December 2024

Q. Please state your name and business address.

A. My name is Michael P. Griffin, and my business address is 4600 Coolidge Highway, Royal Oak, MI 48073.

Q. By whom are you employed?

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

Q. What is your position with Consumers Energy?

A. I presently hold the position of Senior Strategy Manager in the Gas Strategy Department, a position I have held since July 2021.

Q. What are your responsibilities as Senior Strategy Manager?

A. I am responsible for the cross-functional research, analysis, and oversight of natural gas transmission and certain distribution assets and transmission portfolio management strategy. This includes the development, recommendation, and administration of the Natural Gas Delivery Plan ("NGDP").

Q. Please describe your educational background?

A. I earned a Bachelor of Arts in Marketing from Michigan State University in 1985, and earned a Master of Business Administration from Wayne State University in 1998.

Q. Please describe your work experience?

A. I began working for the Company in 1987. Since that time, I have held positions of increasing responsibility including Marketing Consultant, Customer Energy Specialist, Senior Business Support Consultant in the financial area, Gas Budgeting Director, and Director of Rate Cases and Controls, a position I held beginning in 2008. As Director of Rate Cases and Controls, I was instrumental in the development of testimony and exhibits, and in supporting various witnesses in multiple gas and electric rate cases for the Gas and

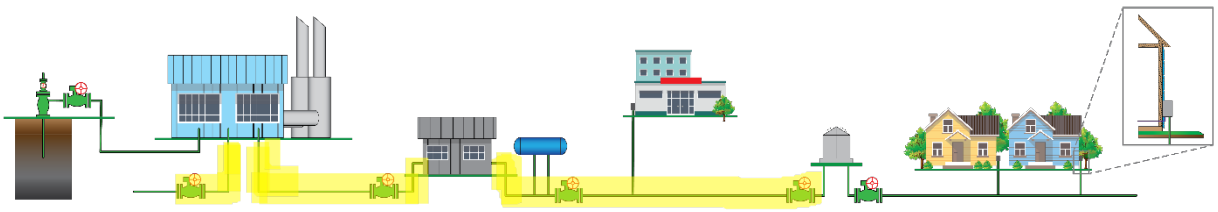
Electric Engineering, Operations, and Customer Operations departments. Since July 2021, I have held the role of Senior Strategy Manager for the Company's transmission assets.

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

A. Yes, I have recently provided testimony in MPSC Case No. U-21148, MPSC Case No. U21308 and MPSC Case No. U-21490.

Q. What is the purpose of your direct testimony?

A. My direct testimony explains the Company's request for rate relief as it relates to its Gas Transmission and certain Distribution capital expenditures and Operating and Maintenance ("O&M") expenses for the programs identified below. These expenditures are primarily related to operations of the Company's high-pressure distribution and transmission systems. Specifically, these investments relate to the portion of the Company system that receives the high-pressure gas at the outlet of the Compressor Stations, and delivers the gas to the city gates, and from the city gates to the regulator stations. In the diagram below, these investments are inside the yellow highlighted section. These investments will help the Company meet its objectives of supplying safe, reliable, affordable, and clean energy to customers as described in the NGDP, Exhibit A-42 (NPD-1), sponsored by Company witness Neal P. Dreisig.



My direct testimony is divided into three sections: (i) Asset Relocation Transmission capital expenditures; (ii) Regulatory Compliance O&M and capital costs; and (iii) Capacity/Deliverability capital expenditures.

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

A. Yes. I am sponsoring the following exhibits:

Exhibit A-58 (MPG -1)		Summary of Actual & Projected Regulatory Compliance O&M Expenses;
Exhibit A-12 (MPG-2)	Schedule B-5.5	Summary of Actual and Projected Capital Expenditures Transmission & Distribution Plant - Summary of Actual & Projected Gas Capital Expenditures;
Exhibit A-59 (MPG-3)		Actual & Projected Gas Transmission Capital Expenditures - Asset Relocation Transmission Program;
Exhibit A-60 (MPG-4)		Actual & Projected Gas Transmission Capital Expenditures – Regulatory Compliance Program;
Exhibit A-61 (MPG-5)		Actual & Projected Gas Transmission and Distribution Capital Expenditures - Capacity/Deliverability Program;
Exhibit A-62 (MPG-6)		Actual & Projected Gas Capital Expenditures - Transmission & Distribution Plant - TED-I Program Detail; and
Exhibit A-63 (MPG-7)		Projected Capital Expenditures - Transmission & Distribution Plant, Summary of Actual & Projected Gas Capital Expenditures.

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

A. Yes.

Q. Please describe Exhibit A-58 (MPG-1).

A. Exhibit A-58 (MPG-1) shows the total O&M expenses for the Regulatory Compliance Program that I am sponsoring. In my testimony, I will describe the program expenses and projects contained within this program. As shown on line 5 of Exhibit A-58 (MPG-1), the total O&M expenses I am sponsoring were $20,034,000 in 2023 and are projected to be $26,737,000 in 2024, $28,512,000 in 2025, and $23,129,000 for the 12 months ending October 31, 2026.

Q. Please describe Exhibit A-12 (MPG-2), Schedule B-5.5.

A. Exhibit A-12 (MPG-2), Schedule B-5.5, shows the total capital expenditures I am sponsoring. In my testimony I will describe each of the programs, any sub-programs, and corresponding expenditures for these items. As shown on line 4 of Exhibit A-12 (MPG-2), Schedule B-5.5, the capital expenditures for the programs I am sponsoring were $350,582,000 in 2023, and are projected to be $313,829,000 in 2024, $176,781,000 for the 10 months ending October 31, 2025, and $219,855,000 for the 12 months ending October 31, 2026.

Q. Does the NGDP discuss the Company's gas transmission assets?

A. Yes, it does.

Q. Please describe the Company's 10-year investment plan for its gas transmission and distribution assets that you are sponsoring.

A. Over the next 10 years, the Company will focus its transmission efforts to continue improving on inspections, reducing risk, and increasing its remediation pace for critical assets. To reach these objectives, the Company has completed the planned Transmission Enhancements for Deliverability & Integrity ("TED-I") pipeline projects and will be moving forward with smaller-scale infrastructure projects like valve replacements and

upgrades, along with line lowerings and the re-build schedule for city gate facilities. This information can be found in Exhibit A-42 (NPD-1), Section IV.C Transmission Asset Plan of the NGDP. The Company is also rebuilding distribution regulator station facilities. This information can be found in Exhibit A-42 (NPD-1), Section IV.D of the NGDP.

I. ASSET RELOCATION TRANSMISSION PROGRAM

Q. Please describe the capital expenditures related to the Asset Relocation Transmission Program as shown on Exhibit A-12 (MPG-2), Schedule B-5.5, line 1.

A. The Asset Relocation Transmission Program includes gas transmission infrastructure replacement projects that are required due to civic improvement activities, initiated by federal, state, or local governmental units. This program also includes projects where transmission pipeline location or depth of cover requires relocation of an existing pipeline to prevent third-party damage, eliminate physical conflicts with other utilities, and ensure continued safe operation. Civic improvement projects replace or improve aging public infrastructure such as roadways, bridges, sewer lines, water lines, and drainage ditches. The Transmission Pipeline Engineering Department reviews all civic improvement projects to determine if conflicts require pipeline relocation. The Asset Relocation Transmission Program also includes relocation and lowering of natural gas transmission infrastructure to remediate reduction in cover due to grading and/or erosion.

For actual and potential asset relocation projects reviewed as a result of civic improvement projects, to minimize scope and expense, the Company works with the governmental units involved to coordinate work and to negotiate design criteria wherever possible. For instance, the Company reviews municipal project plans and tries to negotiate design changes to eliminate potential direct conflicts with Company facilities, such as gas

transmission lines, valve sites, or city gate stations. These negotiations reduce overall project scope and thus reduce the costs to both the taxpayer and the customer.

In addition, to further reduce costs, the Company coordinates project timelines with municipalities to align construction and restoration schedules. An example of the Company's ongoing coordination with municipalities in which civic improvement projects required pipeline relocation was in Oakland County when lowering segments of Line 1600 along Taft Road ahead of scheduled municipal road improvements planned by the City of Novi. This effort was undertaken to minimize disturbance and impact to the community. Furthermore, additional coordination in Saginaw County allowed the Company to lower a segment of Line 300 within the Parker Swamp Drain to safely facilitate scheduled drain maintenance activities.

Projects are also scoped as a result of instances where location or lack of depth of cover requires the relocation of an existing transmission pipeline to ensure continued safe operation and for damage prevention purposes. Projects are evaluated to determine if the reestablishment of cover can be a long-term, viable remediation option. Most projects are not selected for this type of remediation method given the likelihood of continued cover degradation over a period of time. The Asset Relocation Transmission Program projects are designed and constructed to comply with minimum soil cover requirements specified by State and Federal regulations, see, e.g., 49 CFR 192.317, 49 CFR 192.327(a), Michigan Gas Safety Standards, and Company requirements. These project types are described in more detail later in my direct testimony.

As shown on Exhibit A-12 (MPG-2), Schedule B-5.5, line 1, the capital expenditures for this program were $6,168,000 in 2023, and are projected to be

$17,389,000 in 2024, $19,138,000 for the 10 months ending October 31, 2025, and $24,726,000 for the 12 months ending October 31, 2026.

Q. Please describe the development of the Company's Asset Relocation Transmission Program capital expenditure projections.

A. These projections are based upon knowledge of specific projects planned for the next several years and prioritized accordingly by established risk and/or external third-party/civic schedule commitments. Examples of asset relocation projects included in these projected expenditures include:

- Line 300 Parker Swamp Drain Lowering civic improvement in Saginaw County;
- Line 1300 114th Ave line lowering in Allegan County;
- Line 100B Sleepy Hollow State Park ("SHSP") re-route in Clinton County;
- Lines 100A/B/C Chippewa River line lowerings in Isabella County;
- Line 1100 Rabbit River line lowering in Allegan County;
- Line 1200A line lowerings at Wetlands BR014 and BR017 in Branch County;
- Line 1200A Townline Road line lowering in Branch County; and
- Line 1200A Needham Road line lowering in Branch County.

The Company's projected expenditures are required to complete the level of asset relocations for known transmission line lowerings and civic improvement projects. Exhibit A-59 (MPG-3) provides further details on the expenditures included in this program.

Q. Please describe the Line 100B SHSP re-route project.

A. The Company filed for a certificate of public convenience and necessity pursuant to 1929 Public Act 9 ("Act 9") in MPSC Case No. U-21179 on December 15, 2021, for this project. The Act 9 was approved on March 3, 2022. The project was completed in 2024. As described in the Company's Application, page 2, in that case:

> In Case No. U-20618, Consumers Energy received Commission approval pursuant to Act 9 to construct and operate the Mid-Michigan Pipeline to replace the existing Line 100A pipeline between Chelsea and Ovid, Michigan… The Mid-Michigan Pipeline includes a reroute of Line 100A in SHSP away from the campground and beach area to allow for construction during the busy use of the park and removal of the pipeline from heavily used areas… Line 100B is a 26-inch natural gas pipeline that runs parallel to Line 100A through SHSP. Consumers Energy proposes to reroute Line 100B at the same time, and along the same route, as Line 100A. Just as with Line 100A, rerouting Line 100B will remove the pipeline from the heavily used beach and campground areas, and as a result will remove the addition of a valve site due to the reroute being located in a Class 2 area. Removal of the valve site will save approximately $1 million. The reroute away from the beach and campground areas will also result in less impact to park users in the event of future pipeline maintenance or remediation. The reroute of Line 100B will allow Line 100B to continue to parallel Line 100A, which will provide for more efficient and cost-effective maintenance of the pipelines in a single pipeline corridor. Line 100B is currently buried deeper than normal in the park, and rerouting Line 100B will allow the pipeline to be brought to normal depth allowing for improved operations and maintenance.

Q. Please explain the methodology for selecting the Company-initiated projects in the Asset Relocation Transmission Program.

A. Company-initiated projects executed under the Asset Relocation Transmission Program are selected based on a variety of considerations, including physical depth of cover, customer notifications, and Consumers Energy transmission pipeline risk model results, as determined by the Gas Asset Management System Integrity group. Risk modeling for the Asset Relocation Transmission Program involves determining the anticipated overall risk reduction that would result from reducing the relative risk score for third-party damage (by a percentage commensurate with increased depth of cover) and holding all other individual threat risk scores constant. Segments showing a higher overall risk reduction as a result of

increased depth of cover are graded as higher priority within the Asset Relocation Program. Prioritization may also be adjusted based on availability of transmission pipeline outages, continued coordination with local municipalities or governing authorities for civic-related work, and anticipated future replacement under another program (such as TED-I).

Q. Please describe the customer benefits attained from the projects in this program.

A. For Company-initiated Asset Relocation Transmission Projects, replacing and lowering pipeline segments in locations where grading or erosion has reduced cover to less than the depths specified by 49 CFR 192.327(a) and Company standard requirements provides benefits to customers by reducing the potential for third-party damage from activities such as plowing and drain maintenance. For example, industry data for risk management indicates that increasing the depth of cover from 3.0 feet to 4.5 feet reduces the threat of third-party damage occurrence by up to 56% (Muhlbauer, Pipeline Risk Management Manual). These projects also mitigate the risks of additional reduction in cover and future exposure of pipelines, which may in turn result in increased risk of vehicle damage, external loading, coating damage, pipe scouring, washouts, sinking, and corrosion at the soil-to-air interface. For Asset Relocation Transmission Projects initiated by civic improvement projects, customer benefits include reduced risk of third-party damage, maintenance of underground clearances specified by 49 CFR 192.325, and facilitation of the civic improvement projects. Customers also benefit when the Company coordinates with civic improvement projects as street and road disruptions are minimized.

II. REGULATORY COMPLIANCE PROGRAM

Q. Please describe the capital expenditures related to the Regulatory Compliance Program as shown on Exhibit A-12 (MPG-2), Schedule B-5.5, line 2.

A. As shown on Exhibit A-12 (MPG-2), Schedule B-5.5, line 2, the capital expenditures for this program were $36,139,000 in 2023, and are projected to be $26,078,000 in 2024, $24,285,000 for the 10 months ending October 31, 2025, and $24,807,000 for the 12 months ending October 31, 2026.

I am sponsoring the following four programs in the Regulatory Compliance capital program:

- Pipeline Integrity Transmission Program;
- Pipeline Integrity Transmission Operated by Distribution ("TOD") Program;
- Cathodic Compression, Storage and Pipeline Program; and
- Maximum Allowable Operating Pressure ("MAOP") Compliance Pipeline Program.

Q. Please describe the O&M expenses related to the Regulatory Compliance Program as shown on Exhibit A-58 (MPG-1).

A. As shown on line 5 of Exhibit A-58 (MPG-1), the O&M expenses for this program were $20,034,000 in 2023 and are projected to be $26,737,000 in 2024, $28,512,000 in 2025, and $23,129,000 for the 12 months ending October 31, 2026.

I am sponsoring the following four programs in the Regulatory Compliance O&M program:

- Pipeline Integrity Transmission O&M Program;
- Pipeline Integrity TOD O&M Program;
- Corrosion Control Transmission O&M Program; and

- MAOP Transmission O&M Program.

As these O&M expenses are primarily tied to the capital expenditures in the capital programs described above, they will be consolidated below to describe the overall program spending.

A. PIPELINE INTEGRITY TRANSMISSION PROGRAM AND PIPELINE INTEGRITY – TOD PROGRAM

Q. Please describe the Pipeline Integrity Program.

A. The Pipeline Integrity Program represents the necessary inspections and remediation O&M expenses and capital expenditures that allow the Company to remain compliant with regulations mandated by the federal Pipeline & Hazardous Materials Safety Administration ("PHMSA") and the Commission. The program costs are a function of the overall number of assessments, inspection tool types, baseline assessments, or reassessments to be completed in accordance with the Company's Pipeline Integrity Program.

Q. Please describe PHMSA's requirements for a Pipeline Integrity Program.

A. Federal Regulation, 49 CFR Part 192, Subpart O, specifies how pipeline operators must identify, prioritize, assess, evaluate, repair, and validate the integrity of natural gas transmission pipelines that could, in the event of a leak or failure, affect High Consequence Areas ("HCA"). These are areas where pipeline releases could have greater consequences to health, safety, or the environment. As a transmission pipeline operator, Consumers Energy must comply with these minimum federal safety standards. Under 49 CFR 192.907, by December 17, 2004, all pipeline operators, including Consumers Energy, were required to develop and follow a written Transmission Integrity Management Program ("TIMP") that addresses the risks on each covered transmission pipeline segment. In addition, Consumers Energy has updated its standards, procedures, and processes to adhere

to the additional requirements in Safety of Gas Transmission Pipelines, including Repair Criteria, Integrity Management Improvements, Cathodic Protection, Management of Change, and Other Related Amendments ("RIN2") by May 24, 2023, and other dates as outlined in the final rule.

Q. Please describe the MPSC's requirements for a Pipeline Integrity Program.

A. The MPSC has adopted and is the enforcement agency for the federal regulations. Additionally, the MPSC has published the Michigan Gas Safety Standards. These standards are additional rules the Company is required to follow.

Q. What is the importance of a Pipeline Integrity Program?

A. As stated above, a Pipeline Integrity Program is in place to validate and ensure the integrity of pipelines in HCA and outside of HCA, including inline inspectable Moderate Consequence Areas ("MCA") and segments within a Class III or Class IV location operating above 30% specified minimum yield strength ("SMYS"). This program provides a critical avenue that increases public safety through the identification and remediation of potentially hazardous conditions on the pipelines. Additionally, the program is important to ensure the reliability of the Company's transmission system remains intact by taking measures to prevent an unexpected failure on the system.

Q. How was the Company's Pipeline Integrity Program developed?

A. Consumers Energy's TIMP contains information related to how the Company identifies, prioritizes, assesses, evaluates, repairs, and validates the integrity of its gas transmission pipelines that could, in the event of a leak or failure, affect HCA. The TIMP is updated based upon regulations that have become effective since the inceptions of the program. To

minimize environmental and safety risks, Consumers Energy's TIMP delivers the following:

- Identifies HCA, required assessments Outside of HCA, and threats to covered pipeline segments:
  - Assessments Outside of HCA
    - Inline Inspectable MCA; and
    - Segments located within a Class III or IV location operating above 30% SMYS;
- Establishes a baseline assessment plan, including criteria for establishing reassessment intervals, a direct assessment plan, and a communication plan;
- Remediates conditions found during assessments;
- Specifies continual evaluation and assessment of the overall TIMP;
- Establishes a plan for confirmatory direct assessment;
- Requires additional preventative and mitigative measures, recordkeeping, and management of change; and
- Establishes a Quality Assurance process.

Pursuant to the federal regulations, this written document has been modified over the years for various reasons. Some of the reasons for modification include changes in inspection technology, changes or clarifications received from PHMSA, feedback from the MPSC Staff ("Staff"), and Company-driven changes.

Q. Is the TIMP Manual provided to Staff?

A. Yes. Staff has access to the Company's TIMP Manual, and when revisions to the TIMP Manual are made, a copy is sent to Staff.

Q. As part of Transmission Integrity Management, do companies need to continuously improve their program?

A. Yes, 49 CFR 192.907 and 49 CFR 192.911 require that an operator must make continual improvements to the program.

Q. Does the Company's NGDP, Exhibit A-42 (NPD-1), discuss Consumers Energy's 10-year plan related to the Pipeline Integrity Program?

A. Yes. Over the 10-year period of the NGDP, the Company is focusing on improving inspections, de-risking, and increasing its remediation pace for critical assets. The Company is continuing its current practice of striving toward six-year inspection and remediation cycles. The Company is updating its risk ranking methodology and transitioning its current relative risk model into a probabilistic risk model to ensure investments are concentrated on the right assets. As discussed in the NGDP, the Company will undertake the following:

- Complete baseline inspections for approximately 25 miles of the Company's mainline transmission system pipeline by year-end 2025 and maintain that plan based on a reassessment plan;
- Assess and develop a plan to proactively remediate high-risk pipe segments that are prone to higher risk threats like Stress Corrosion Cracking ("SCC") and corrosion; and
- Evaluate transmission-classified segments embedded in the distribution system—referred to as TOD—to determine if a baseline assessment or replacement is needed on a prioritized basis.

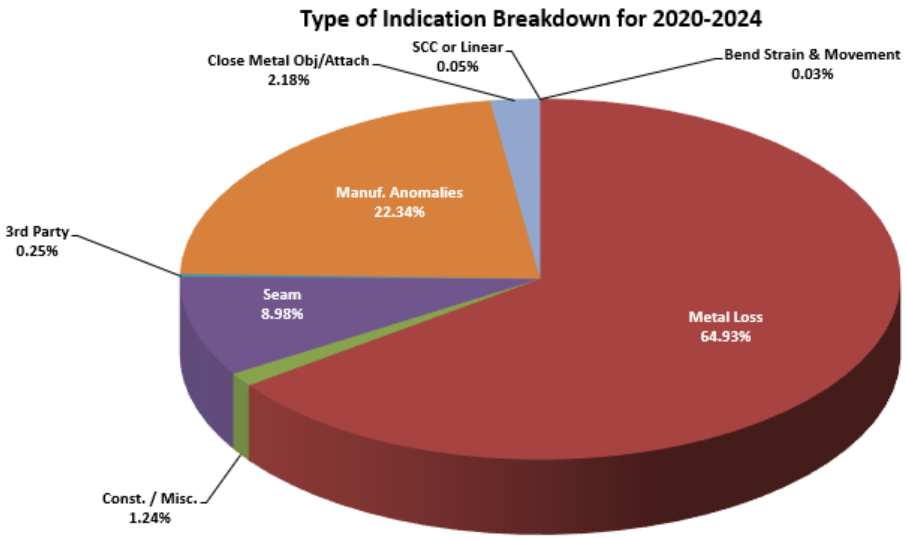
Exhibit A-42 (NPD-1), Section IV.C.2, provides additional information on these objectives.

Q. What types of anomalies and threats has the Company experienced on its gas transmission system?

A. Consumers Energy's TIMP has proven to find anomalies the Company is able to remediate, providing safe and reliable operations for customers. The Company has experienced several different types of anomalies on its gas transmission system, and continues to find new pipeline safety threats that require mitigation, as detailed later in my direct testimony. A breakdown of the type of anomalies found through traditional in-line inspection ("ILI") tool runs from 1999 to 2024 is shown in the Figure 1 below:

Figure 1

Type of Anomalies Found Through ILI Tool Runs 2020 through 2024



The anomaly indications are as follows:

1. Metal Loss encompasses all external and internal corrosion in the body of the pipe that has been predicted by the ILI tools;

2. Manufacturing anomalies include metal loss due to the manufacturing of the pipe and other manufacturing anomalies predicted in the body of the pipe;

3. Seam anomalies covers all external and internal corrosion in the seam weld, crack indications in the seam, and metal loss in the seam weld due to manufacturing processes;

4. Construction and Miscellaneous category include reinforced girth welds, sleeves, and other items that appear on or near the pipeline;

5. Metal Object and Attachment category includes extra metal and close metal objects to the pipelines;

6. Third-Party Damage includes any dents, deformations, and gouges on the pipelines;

7. SCC or Linear includes crack indications found in the body of the pipe and not on a seam; and

8. Locations on the system that have indication of Bend Strain or pipeline movement due to geohazards or construction activities.

As illustrated in the chart, the largest percentages of anomalies are metal loss or corrosion. From an industry perspective, corrosion is the number one threat to a transmission pipeline system. In keeping with regulatory and industry requirements, the Company promptly addresses this threat through a strong TIMP, and a robust corrosion control process that reduces the corrosion rate on pipelines.

The Company's TIMP program also addresses the threat of SCC. Many factors can affect the initiation and propagation of SCC, but a primary barrier to SCC is a pipeline's coating system. A secondary barrier is a cathodic protection system. When the coating on a pipe is compromised, the environmental factors that support SCC can develop under the right conditions. Since 2015, the Company has been assessing its pipelines that have the highest potential for SCC to occur, and there have been instances where SCC was found and remediated.

The Company also continues to conduct bending strain analyses and pipe movement studies on sections of its natural gas transmission system to identify potential

areas of high strain on its transmission pipelines. Since 2017, the Company has performed 62 bending strain analyses and performed remediation based on those results to improve the safety and reliability of the system.

Q. Is a probabilistic risk model recommended by federal or state regulators?

A. Yes, both. PHMSA has identified the probabilistic risk model as a potential best practice for pipeline operators over other risk models, as discussed in the technical information document, Pipeline Risk Modeling: Overview of Methods and Tools for Improved Implementation, published February 1, 2020, by PHMSA. Additionally, the MPSC recommended the transition in its September 11, 2019 Michigan Statewide Energy Assessment Final Report ("SEA").

Q. What are the additional benefits of a probabilistic risk model for the safety and reliability to customers?

A. When transmission risk modeling was first required by PHMSA, the industry explored the best options available to comply with regulations. The best option available at that time was a relative risk model, which uses a scoring system to weight the different threats to the pipeline to rank the pipelines within a transmission system relative to each other. The scoring system used values based upon subject matter expert opinion and experience, and therefore, the model was not a true statistical model. A true statistical model, or probabilistic model, had not yet been developed for the industry due to its complexity. Therefore, the relative model provided the best method to assess risk and is what the Company has been using.

In the last several years probabilistic models have been developed, and show great promise as a tool in more accurately assessing pipeline risk. The use of a model that is

entirely data driven provides a more accurate representation of the risks associated with pipelines. This in turn will allow the Company to more precisely mitigate risks associated with its transmission system to improve customer safety and reliability. While the inputs of the model are data driven, the model results will still require subject matter expert interpretation, verification, and understanding of those results. The Company has completed extracting, transforming, and loading of the data in addition to the asset configuration, training, and testing of the probabilistic risk model. The first run of the model was completed in 2023, The probabilistic risk model is utilized to prioritize work, to ensure the urgency of action taken is appropriate to mitigate the threats on that segment, and to ensure the correct mitigative actions are taken to ensure safe operation of the asset. This is a fully quantitative approach to risk modeling allowing an objective view of the risk, threats, and impacts related to the gas assets. The Company intends to implement probabilistic risk models in the future for other asset classes so that risk and risk reduction measures can be prioritized across the entire system using a more common scale, beginning with Storage assets with the probabilistic risk model implementation complete by year end 2024.

Q. Please explain the development of the Pipeline Integrity Transmission O&M expenses.

A. As shown on Exhibit A-58 (MPG-1), line 4, the Company's Pipeline Integrity - Transmission O&M expense was $17,089,000 in 2023, and is projected to be $22,275,000 in 2024, $23,110,000 in 2025, and $17,128,000 for the test year ending October 31, 2026. The mileage the Company intends to inspect in 2023 through 2026 is shown in Table 1 below. The O&M cost projections for remediation digs are based upon recent inline

inspection results. The O&M includes costs for inspections, remediation, and where applicable material verification and MAOP reconfirmation.

Table 1

Inspection Mileage			
2023	2024	2025	2026
266.5	374.6	320.7	206.4

Additionally, there are certain baseline assessments on longer pipeline segments that will lead to additional digs. These expenses were not projected utilizing inflation factors.

Consumers Energy recognizes there is risk related to public safety and employee safety on pipelines outside of HCA, and is inspecting and remediating those segments, which are also included in the expenses in this program. Through previous inspections performed on non-HCA segments of pipeline, the Company has been able to gather additional data regarding the integrity of its overall transmission system. Similar anomalies are found in both non-HCA and HCA because the pipeline characteristics are the same. The data shows that most of the anomalies found and remediated on Consumers Energy's transmission system are in non-HCA.

Q. Are there additional activities included in the Company's Pipeline Integrity Transmission O&M expenses?

A. Yes. The Company's projection also includes the performance of geohazard assessments of the Company's transmission pipeline systems. These geohazard assessments will provide additional information on potential geohazard outside force threats to the Company's transmission pipelines. This additional information will inform the Company's risk/threat assessments and potential mitigative measures the Company can

take to minimize those threats on the transmission system. Included in the projection is additional material testing on remediation digs where the Company does not have all necessary material properties as required by the Material Verification section of the Safety of Gas Transmission Pipelines: MAOP Reconfirmation, Expansion of Assessment Requirements, and Other Related Amendments rule.

The Company's projection also includes the performance of bending strain analyses and pipe movement studies. Additionally, running Electro Magnetic Acoustic Transducer ("EMAT") tools on pipelines that are susceptible to SCC is part of this projection. Through the use of EMAT tools, the Company has detected and remediated different anomalies than what has previously been found using more traditional ILI tools.

Q. Please describe the Pipeline Integrity – TOD Program.

A. In addition to ILIs and remediation on the transmission system, the Company performs assessments of TOD pipe. These pipeline segments are operated on the distribution system above 20% Specified Minimum Yield Strength and thus are covered under the Transmission regulations. As shown on Exhibit A-58 (MPG-1), line 3, the Company's Pipeline Integrity – TOD Program O&M expenses were $812,000 in 2023, and is projected to be $1,059,000 in 2024, $1,085,000 in 2025, and $1,420,000 for the test year ending October 31, 2026. For pipe within HCA, the Company assessed 14.8 miles in 2023 and will assess 15.6 miles in 2024, 23.1 miles in 2025, and 11.8 miles in 2026. Assessments include inspection digs for External Corrosion Direct Assessment ("ECDA"), inspection digs for Internal Corrosion Threat Evaluation, or Internal Corrosion Direct Assessment ("ICDA"). Dig locations are determined from analysis of survey and historical corrosion issues. In addition, starting in 2023, the Company began performing ECDA assessments

on non-HCA segments to reduce overall risk on TOD assets. The additional survey and assessment digs are why there is an increase in O&M expense between 2023 and 2026. The indirect surveys needed to perform the direct assessments are included in the O&M expense. Also, ECDA digs that result in coating repairs only, verification digs, and additional assessments on non-HCA pipelines are included in the projection.

Q. Please explain the development of the Pipeline Integrity - Transmission capital expenditures.

A. As shown on Exhibit A-60 (MPG-4), line 1, the capital expenditures for this program were $16,148,000 in 2023, and are projected to be $13,381,000 in 2024, $10,504,000 for the 10 months ending October 31, 2025, and $5,144,000 for the 12 months ending October 31, 2026, as set forth on this exhibit on line 1, column (b); line 1, column (c); line 1, column (d); and line 1, column (f), respectively.

Pipeline Integrity - Transmission expenditures include remediation of pipeline anomalies where 50 feet or more of pipe is replaced, the installation of Ultrasonic Thickness ("UT") sensors, corrosion coupons, and robotic ILIs. Both UT sensors and corrosion coupons allow the Company to measure and determine the corrosion rate to determine current condition and potential replacement. Internal UT sensors physically measure the pipe wall and allow the Company to obtain this information without physically digging up the location. This reduces the need to re-excavate the same locations every seven years to evaluate the condition of the pipe as would be required if the sensor was not installed, thus reducing costs to determine the integrity of the pipe at that location. Corrosion coupons (external corrosion) tell the Company the corrosivity of the soil and the

adequacy of the cathodic protection to help ensure system integrity. The Company anticipates 15% of the remediation digs will be capital.

Q. Please explain the development of the Pipeline Integrity – TOD Program capital expenditures.

A. As shown on Exhibit A-60 (MPG-4), line 2, the capital expenditures for this program were $9,274,000 in 2023, and are projected to be $6,119,000 in 2024, $5,593,000 for the 10 months ending October 31, 2025, and $9,998,000 for the 12 months ending October 31, 2026, as set forth on this exhibit on line 2, column (b); line 2, column (c); line 2, column (d); and line 2, column (f), respectively.

As part of the direct assessments performed, UT sensors (for internal corrosion) and UT coupons (for external corrosion) are frequently installed to monitor corrosion rates. The corrosion rate information is then reviewed and evaluated to determine the effectiveness of corrosion control measures. To date, approximately 1,457 UT sensors and 916 UT coupons have been installed. Typical remediation of pipe found during the inspections involves pipe replacements.

Q. Are there any additional details you would like to provide regarding significant projects included in the Pipeline Integrity – TOD Program?

A. Yes. In 2023, new requirements were implemented that increased requirements for ICDA assessments. These changes increased the number of excavations required to complete an ICDA assessment. While there was an increase in dig requirements, installation of UT sensors during prior assessment digs reduce the total number of excavations being perform since many of the required locations were already being monitored.

B. CORROSION CONTROL – TRANSMISSION PROGRAM AND CATHODIC COMPRESSION, STORAGE, AND PIPELINE PROGRAM

Q. Please describe the Corrosion Control – Transmission O&M Program.

A. The O&M expense for the Corrosion Control – Transmission Program was $947,000 in 2023, and is projected to be $1,505,000 in 2024, $1,955,000 in 2025, and 2,210,000 for the test year ending October 31, 2026, as shown on Exhibit A-58 (MPG-1), line 2. O&M expenses for corrosion control on the transmission system include special projects like large atmospheric painting projects, pipeline recoating projects, shorted casing remediation and close interval surveys. Similar to the capital program (Cathodic Protection – Compression, Storage and Pipeline), O&M projects are typically identified during yearly surveys and typically occur in a short timeframe. The Company's projected expense amount is based on historical averages (100 miles of close interval survey), the re-coating of pipeline sections that have poor coating conditions based on the close interval surveys, and work to clear shorted casings. The projected expense also includes additional atmospheric painting projects at sites that have not been painted in several years and that have had numerous small touch-ups done to prevent corrosion. This additional work will not only allow the Company to continue to meet the regulatory obligations for corrosion control, but also will ensure and enhance the safety of its natural gas delivery systems. These expenses were not projected utilizing inflation factors.

Q. Please describe the Cathodic Compression, Storage, and Pipeline Capital Program.

A. The Cathodic Compression, Storage, and Pipeline Capital Program allows the Company to maintain compliance with federal regulations for cathodic protection of facilities. As shown on Exhibit A-60 (MPG-4), line 3, the capital expenditures for the Cathodic

Compression, Storage, and Pipeline Capital Program were $5,931,000 in 2023, and are projected to be $6,526,000 in 2024, $5,779,000 for the 10 months ending October 31, 2025, and $6,649,000 for the 12 months ending October 31, 2026, as set forth on this exhibit on line 3, column (b); line 3, column (c); line 3, column (d); and line 3, column (f), respectively. The capital activities included in this program are the installation of new or replacement rectifiers and anode beds, the installation of UT Coupon Test Stations and Remote Monitoring Units ("RMUs"), installation of Alternating Current ("AC") mitigation, the installation of insulators, and installation of permanent UT sensors and coupons for monitoring corrosion rates for its Transmission system. The projects undertaken are identified during yearly routine inspections of the cathodic protection systems. When issues are identified, like pipe-to-soil potentials below criteria, repairs typically must occur within one year of identification. As such, the dollar amounts identified for these programs are based on historical averages. One area that has increased in this program is the installation of AC Mitigation. These projects are intended to mitigate stray AC voltages on the pipeline that can cause corrosion or a shock hazard. Additionally, new rules implemented by PHMSA in 2022 require additional testing and mitigation for possible stray current issues. As a result of these additional requirements, the Company has increased monitoring and identified projects to mitigate stray AC voltages.

C. MAOP COMPLIANCE PIPELINE PROGRAM AND MAOP TRANSMISION PROGRAM

Q. Please describe the MAOP Compliance Pipeline Program.

A. The MAOP Compliance Pipeline Program involves MAOP verification and remediation of the Company's transmission pipelines, including Transmission Operated by Distribution pipelines. This work initially began in 2012, in response to the Pipeline Safety, Regulatory

Certainty, and Job Creation Act of 2011, which required the PHMSA to direct each owner or operator of a natural gas transmission pipeline and associated features to provide verification that their records accurately reflect a pipeline's MAOP. This will improve compliance with state and federal pipeline records requirements and confirm historic system MAOP values. On October 1, 2019, PHMSA published the Safety of Transmission & Gathering Lines Rule which codifies the requirement for MAOP establishing documentation to meet traceable, verifiable, and complete criteria. This rule is also identified starting on page 83 of the SEA, which states:

> In 2016, PMHSA published a proposed rulemaking titled "Pipeline Safety: Safety of Gas Transmission and Gathering Pipelines" to update 49 CFR Part 192. This proposed rule included significant changes to the transmission integrity management requirements, along with other general changes to transmission and gathering pipelines with enhancements to the following areas:
> 1. Re-establishing maximum allowable operating pressure.
> 2. Verifying material properties.
> 3. Performing integrity assessments outside of high-consequence areas.
> 4. Management of change enhancements.
> 5. Corrosion control enhancements.
> 6. Modifying the regulation of onshore gas gathering lines.

Q. How will the Company verify and adequately document the MAOP of these pipelines?

A. This will be accomplished with a detailed engineering analysis or Standardized Engineering Analysis of the Company's Transmission System. The analysis will determine where work is required to meet the traceable, verifiable, and complete criteria, and upgrade the documentation archiving from a historical perspective to a newly developed engineering content management database integrated with the Company's geospatial information system database. The record database will link record files to the data mined from those records and entered into the geospatial information database for

MAOP calculation from those design and testing values. For each transmission pipeline segment identified as not meeting the record criteria established by the newly published rule, the Company will address these segments through an engineering evaluation that will consider the six regulatory methods of MAOP Reconfirmation identified in 49 CFR 192.624 in conjunction with a solution that provides benefits in regard to pipeline safety, reliability, and deliverability. The six methods are:

1. Pressure Test;
2. Pressure Reduction;
3. Engineering Critical Assessment;
4. Pipe Replacement;
5. Pressure Reduction for Pipeline Segments with Small Potential Impact Radius; and
6. Alternative Technology.

Material verification will require a management program for identifying pipeline segments for which the material property value documents necessary to calculate MAOP are not Traceable, Verifiable, or Complete. The management program will provide identification of those segments for when the Company may expose pipe for purposes other than the 49 CFR 192.614 Damage Prevention Program. When exposed, these segments would require either destructive or nondestructive testing to attain material property values. Evaluation is based on an analysis including, but not limited to, the following factors:

- Nature of the records gap identified (e.g., segments with material verification issues prioritized for replacement);
- Pipeline performance history and pipeline field evaluations;
- Minimizing the impact of service to customers;

- Coordination with other planned work and the need to maintain service to customers; and
- Pipeline location and cost to replace (i.e., population density).

Depending upon the work performed, the project would be an O&M expense or a capital expenditure. The Company's MAOP Reconfirmation capital expenditure projections are based on previously completed work orders of similar magnitude and requirements when pipe replacements are performed. As shown on Exhibit A-60 (MPG-4), line 4, the capital expenditures for the MAOP Compliance Pipeline Capital Program were $4,786,000 in 2023, and are projected to be $51,000 in 2024, $2,409,000 for the 10 months ending October 31, 2025, and $3,016,000 for the 12 months ending October 31, 2026, as set forth on this exhibit on line 4, column (b); line 4, column (c); line 4, column (d); and line 4, column (f), respectively. The projects in 2023 include replacement of piping on Line 1400 underneath Milford Rd and replacement of piping and valves on Line 100A at Mt. Pleasant Station. The capital project planned for 2024 is the retirement of drain piping at the Mt. Clemens City Gate on Line 1060. Capital projects planned for 2025 include the replacement of valves and piping at Metamora City Gate on Line 1900. The Company continues to monitor the gas system for segments without Traceable, Verifiable, and Complete pressure tests to comply with the new PHMSA-published Safety of Transmission & Gathering Lines Rule. Future projects will be identified from the above-mentioned Standardized Engineering Analysis.

Q. Are there any proposals the Company is requesting the Commission to approve that would impact future expenditures in this program?

A. Yes. Company witness Heather L. Rayl describes in her direct testimony a request for the Commission to approve the capitalization of hydrotesting of pipelines, in certain

circumstances, to re-confirm the MAOP of these pipelines. The Company does not have any of these projects that would be impacted by this request included in this docket, but anticipates there could be projects in the near future for which it would.

Q. Please describe the O&M expenses related to the Regulatory Compliance - MAOP Transmission Program as shown on Exhibit A-58 (MPG-1), line 1.

A. As shown on Exhibit A-58 (MPG-1), page 1, line 1, the O&M expenses for this program were $1,187,000 in 2023, and is projected to be $1,898,000 in 2024, $2,361,000 in 2025, and $2,370,000 for the test year ending October 31, 2026. The test year O&M expense comprises four parts.

The first part is an annual expense of $489,000 for an Aerial population density survey to fulfill the Federal Regulations within 49 CFR 192, more specifically 49 CFR 192.609 and 49 CFR 192.611.

Second, there are two projects occurring on Line 1500 and two on Line 1060 ~~1900~~. These projects involve pressure testing the launcher and receiver barrels at St. Clair compression station, Rochester valve site, Grand Blanc valve site, and Atlas valve site to re-establish MAOP.

The third part of the test year expense is an annual expense of $50,000 for Third Party Coordination Surveys. To limit risk, both physically and/or fiscally, this expense will utilize survey data to collect information to determine location (vertical and horizontal) during the pre-planning period. The information gathered through survey data can proactively provide details of Company facilities and will be incorporated into third party plans where potential conflicts can be identified and mitigated prior to the third party construction. This data will primarily be utilized for Asset Relocation projects.

The fourth part of the test year expense is due to expensing the O&M portion of the Standardized Engineering Analysis costs. In 2021, in response to a Staff recommendation in MPSC Case No. U-20650, the Company moved the SEA expenditures to Account 183.2 - Other Preliminary Survey and Investigation Account. The Company is proposing in this proceeding to expense the O&M portion of this account for the 2023 time period, based upon the percentage of orders that resulted in an O&M or capital replacement. The Company proposes to continue the practice of expensing a portion of the Account 183.2 balance in subsequent general rate case proceedings. The capital portion of the account will be allocated to future capital projects. In 2024, the Company expensed $743,971 for the 2022 SEA expenditures. Table 2 below shows the SEA amounts expensed in 2024, and the SEA amount to be expensed in the test year.

Table 2

SEA Expensed in 2024 and the Test Year

Year	Direct Cost	O&M %	O&M Cost
2022	1,323,792	56%	743,971
Amount Expensed in 2024			**$ 743,971**
Year	Direct Cost	O&M %	O&M Cost
2023	1,328,265	85%	1,122,384
Test Year Amount			**$ 1,122,384**

The projects and expenses in 2024 and 2025, for the MAOP Transmission O&M Program and for the test year are shown in Table 3 below. These expenses were not projected utilizing inflation factors.

Table 3

Regulatory Compliance O&M Expenses by Project

Regulatory Compliance - MAOP Transmission O&M Expenses	2025	2026	12 Months Ending Oct 31, 2026
Aerial High Resolution Imagery Survey for Class Location Studies	489,000	489,000	489,000
STC-LN 1060 Mt. Clemens LR Pressure Test	-	369,000	322,875
STC-LN 1060 St. Clair LR Pressure Test	-	341,000	298,375
STC - Line 1500 St Clair LR Pressure Test	350,000	-	43,750
STC - Line 1500 Rochester LR Pressure Test	350,000	-	43,750
3rd Party Coordination Survey Studies	50,000	50,000	50,000
MSEA O&M Projects	1,122,384	1,043,645	1,122,384
Total MAOP Transmission Expense	**2,361,384**	**2,292,645**	**2,370,134**

Company witness Rayl discusses the reduction to rate base for the 2024 amount.

Q. Please explain page 2 of Exhibit A-58 (MPG-1).

A. Page 2 of Exhibit A-58 (MPG-1) presents an illustration of the amounts of the O&M expenses I am sponsoring if one were to apply an inflation rate to the historical O&M expenses. The expenses that I am supporting are based upon the expenses necessary to comply with regulations and improve system safety as described for the programs above, and have not been projected utilizing inflation factors.

III. CAPACITY/DELIVERABILITY PROGRAM

Q. Please describe the capital expenditures relating to the Capacity/Deliverability Program as shown on Exhibit A-12 (MPG-2), Schedule B-5.5, line 3.

A. As shown on Exhibit A-12 (MPG-2), Schedule B-5.5, line 3, the capital expenditures for this program were $308,275,000 in 2023, and are projected to be $270,362,000 in 2024, $133,358,000 for the 10 months ending October 31, 2025, and $170,322,000 for the 12 months ending October 31, 2026. These capital expenditures address needed increases

in transmission pipeline capacity and ensure measurement accuracy, which help ensure adequate capacity and deliverability throughout the system. These expenditures are driven by projects in TED-I, Deliverability Base Field Measurement, Deliverability Base Pipeline, Regulator Stations – Distribution, and Transmission and Storage ("T&S") City Gates as further described below.

Q. Why are Capacity/Deliverability projects necessary?

A. Capacity requirements can increase due to changes in customer population density in specific locations, and also because of changes in system requirements. Examples of changes in system requirements include the need to support load and maintain pressure (both base and peak day), as well as the need to ensure pipeline configuration to allow for in-line inspection through the Pipeline Integrity Program. Deliverability Program expenditures include city gate and regulation station rebuilds and improvements. This program also includes expenditures for the TED-I projects to ensure continued safe, reliable, and deliverable operation of transmission pipelines. Other project work in this program includes investments to ensure gas quality and gas measurement accuracy. Natural gas quality is critical to ensuring that customers' equipment functions properly and safely. Natural gas measurement accuracy ensures that Consumers Energy is properly measuring and accounting for gas purchased for and delivered to customers, as detailed below.

A. TED-I PROJECTS

Q. Please explain the TED-I projects shown on Exhibit A-61 (MPG-5), line 1.

A. The TED-I projects are focused on maintaining deliverability and integrity, and on improving the ability to control gas flows. As shown on Exhibit A-61 (MPG-5), line 1, the

capital expenditures for the TED-I Program were $216,361,000 in 2023, and are projected to be $146,790,000 in 2024, $20,192,000 for the 10 months ending October 31, 2025, and $19,145,000 for the 12 months ending October 31, 2026. Major projects include replacing transmission pipeline segments that contain higher-risk type pipe to ensure integrity and safe operation. In certain cases, city gate stations may be upgraded to enable abandonment of a pipeline or to reduce pressures on pipeline segments to comply with any new MAOP requirements of replacement pipelines. Also included in TED-I are the installation of Remote Control Valves ("RCVs") and Pressure-Limiting Devices ("PLDs") to control pressure and flows during normal operations and in the event of abnormal operation.

Q. Please describe Consumers Energy's investments in its natural gas transmission system as part of the TED-I projects and how they benefit customers.

A. As described in the NGDP, Exhibit A-42 (NPD-1), Section IV.C.2, TED-I pipeline projects improve customer reliability and advance public safety by replacing or retiring higher relative risk pipe segments and, in some cases, increase capacity. Additionally, the replaced pipelines also have enhanced pipeline pressure control and isolation capabilities.

Q. Please explain the TED-I major pipeline projects.

A. TED-I major pipeline projects focus on maintaining integrity and deliverability, and include transmission pipeline replacements of higher relative risk pipe to ensure integrity and safe operation. Higher relative risk pipe includes segments with previous anomalies or stress characteristics related to integrity management risk mitigation. Capacity requirements are factored into line replacements to ensure customer deliverability. The major TED-I construction project included in this filing is the Mid-Michigan Pipeline project which was put into service in 2024.

Q. Please describe the Mid-Michigan Pipeline project.

A. The Mid-Michigan Pipeline project replaced approximately 55 miles of Line 100A, between Ovid City Gate in Clinton County and Chelsea Interchange in Washtenaw County. The project addresses integrity and deliverability concerns with the current pipeline and increase the diameter of the pipeline, from 20-inch to 36-inch within existing pipeline right-of-way ("ROW").

Q. Has the Company received Commission approval to construct and operate the Mid-Michigan Pipeline?

A. Yes. The Commission issued an Order in MPSC Case No. U-20618, on November 19, 2020, approving the Mid-Michigan Pipeline, which authorized Consumers Energy to construct and operate this pipeline.

Q. Please identify capital expenditures for the Mid-Michigan Pipeline.

A. Exhibit A-62 (MPG-6), line 1, identifies the total capital expenditures for the Mid-Michigan Pipeline project. The capital expenditures for this project were $201,391,000 in 2023, and are projected to be $145,589,000 in 2024, $6,935,000 for the 10 months ending October 31, 2025, and $389,000 for the 12 months ending October 31, 2026 (please see Table 4 with detailed expenditures by year). In 2023 through October 31, 2026, projected costs will be incurred for construction, engineering and design, environmental assessment, surveying, and real estate. A summary of this information is provided in the Table 4 below:

Table 4

Mid-Michigan Pipeline Annual Projects & Expenditures

Year	Segment	Length	Projected Spend
2023	Pipeline Construction Phase 1, Additional pipe needed for phases 1 & 2, Stockbridge City Gate & Pleasant Lake City Gate Rebuilds, Long Lead Material Procurement for Phase 2, Engineering, Real Estate, Environmental, Permitting on multiple projects	Approx 30 miles	$201. million (actual)
2024	Pipeline Construction Phase 2, Restoration on Phase 1, Ovid City Gate Rebuild, Engineering, Real Estate, Environmental, Permitting	Approx 25 miles	$146 million (full year projection)
2025	Restoration on Phase 2 and EGLE permitting requirements for wetlands & streams	n/a	$7 million (full year projection)
2026	EGLE permitting requirements & any remaining restoration	n/a	$389 thousand

Major construction commenced in 2023 and concluded in 2024. Site restoration and environmental monitoring will continue beyond 2024.

Q. Why was the Mid-Michigan Pipeline project necessary?

A. The Mid-Michigan Pipeline project is part of the Company's transmission enhancement plan to ensure system safety, integrity, and deliverability. The Line 100A project involved the replacement of 1949 vintage pipe that had demonstrated integrity issues. In May 2015, this line experienced a rupture just north of Chelsea. The project also increased the capacity of the Company's natural gas transmission system. The increased capacity provides a more resilient and flexible system capable of supporting the continued increase in system outage days required by regulatory requirements and other operational maintenance needs.

Q. What other projects are included in the TED-I Program?

A. As described above, also included in TED-I are the installation of RCVs and PLDs to control pressure and flows during normal operations, and in the event of abnormal

operation. The installation of these devices is consistent with federal and state guidance. In the SEA, at page 200, the Commission recommended that "utilities continue to conduct analyses to evaluate increasing the number of remote shutoff valve systems in high consequence areas to minimize the impact during emergency events." Further, in April 2022, PHMSA promulgated regulations requiring operators to install automatic shutoff valves or RCVs on new and entirely replaced transmission pipelines as a means of rupture detection and mitigation. Recognizing the significance of these devices, the Company has developed a comprehensive RCV installation plan as outlined in of the NGDP, Exhibit A-42 (NPD-1), Section IV.C.2.

Q. Please explain the RCV expenditures.

A. The Company is planning to install RCVs on complete pipeline replacements, such as Line 100A (Mid-Michigan Pipeline Project). The costs for those RCVs are included in the project expenditures. RCVs are also being installed to reduce response time on certain Class 4 locations and Class 3 locations within HCAs to improve public safety. The costs for those RCVs are included in the Deliverability Base Pipeline Program. The valves do not prevent failures from occurring but are intended to minimize the time gas flows after a failure and any subsequent fire that would prevent emergency first responders from entering the impacted area. RCVs reduce the loss of natural gas should a pipeline failure occur and can be operated remotely by Gas Control for potential reduction in response times. RCVs will not close inadvertently due to load changes, purging activities, or failure of sensing lines. In 2023, the Company installed 37 RCVs and is projected to install 17 in 2024, 17 in 2025, and 16 in 2026. These installation numbers represent all RCVs installed in all programs and projects. Exhibit A-62 (MPG-6), line 3, identifies the total capital

expenditures for RCVs not otherwise installed in other programs. The capital expenditures for these RCVs were $2,253,000 in 2023, and are projected to be ($103,000) in 2024, $8,717,000 for the 10 months ending October 31, 2025, and $18,074,000 for the 12 months ending October 31, 2026.

Q. Please explain the reason for the variability in expenditures for RCVs from 2023 to the test year.

A. As explained above, RCVs are also installed in other programs and projects. In 2023, nine RCVs were commissioned (programming and remote testing) but installed in 2022. There were also 18 RCVs installed as part of the Mid-Michigan Pipeline project. In 2024, all of the RCVs installed were either on the Mid-Michigan Pipeline or in the Deliverability Base Pipeline program. In 2025, many of the RCVs are being installed alongside other projects so some of the costs are shared with those projects. In 2026, the majority of RCVs will be stand-alone projects with most of cost being charged to the TED-I program.

Q. Please explain the PLD expenditures.

A. The PLD installation locations are selected pursuant to 49 CFR 192.619 and 49 CFR 192.195. As modification of the Consumers Energy pipeline system occurred due to class location changes, system additions, and purchases over the years, the MAOPs were impacted. Historically, Consumers Energy's Gas Transmission System used pressure drop on pipelines when related to MAOP pressures differences, as outlined within 49 CFR 192.619 and 49 CFR 192.609(e), which states that: "[t]he maximum actual operating pressure and the corresponding operating hoop stress, taking pressure gradient into account, for the segment of pipeline involved;". Additionally, Consumers Energy's Gas Control Operations used remotely operated valves for MAOP protection of the Company's

system. As technology has advanced, the industry has recognized that a better and safer way to control pressures is through the use of on-site overpressure protection devices using a pressure-regulated monitor valve/worker valve arrangement, commonly referred to as PLDs. These configuration enhancements automate the device and allow for quicker response and improved safety on the gas transmission system. Public safety risk is reduced when PLD equipment is installed, which is reliable and adequately protects against potential over pressurization. The Company continually analyzes the pipeline system for areas where the operational safety of the system should be enhanced. As a result of this analysis, the Company identified a need to install PLDs and established a prudent plan to improve the system and customer safety. The 2023 projects included:

- Line 4060 Vector Hartland, Howell;
- Line 1200A CE-ANR Stag Lake, White Pigeon; and
- Line 2700 Squirrel Rd Valve Site, Lake Orion;

The installation of PLDs improves the operation of the system and provides enhanced public safety. Exhibit A-62 (MPG-6), line 2, identifies the total capital expenditures for PLDs. The capital expenditures for PLDs were $12,156,000 in 2023, and are projected to be ($133,000) in 2024, $0 for the 10 months ending October 31, 2025, and $0 for the 12 months ending October 31, 2026. The PLD installation program was completed in 2024.

Q. What other projects are included in the TED-I Program?

A. Also included in this program are projects that are smaller in scope and related to other TED-I projects that are not RCVs nor PLDs. These include valve site junctions so the Company can use the existing pipelines for outage or other emergent situations and final

restoration, property acquisition, and closure of environmental permit requirements related to completed pipeline and other major projects. As part of this program the Company is planning a transmission interconnect with DTE Gas Company in 2025 that will improve overall system resiliency to benefit customers of both utilities. Exhibit A-62 (MPG-6), line 4, identifies the total capital expenditures for Pipeline & Other Installations/ Modifications. The capital expenditures for these projects were $561,000 in 2023, and are projected to be $1,437,000 in 2024, $4,540,000 for the 10 months ending October 31, 2025, and $682,000 for the 12 months ending October 31, 2026.

Q. Please provide further information concerning the transmission interconnect project.

A. The transmission interconnect project, which the Company calls the Oakland Resilience Interconnect, is a project the Company is coordinating with DTE Gas and is for the benefit of both utilities' customers. This project is part of the Company's response to Natural Gas Recommendations for Mitigating Risk, found within the SEA. Once built, this facility will allow either utility to provide natural gas to the other utility to address an emergency, as defined in 18 CFR 284.262, that poses a risk to the ability to provide natural gas service for customers in the State of Michigan. Natural gas supply through this interconnect in response to an emergency will be provided in a best-efforts manner. DTE Gas and Consumers Energy received a certificate of necessity to construct and operate the interconnect through an Act 9 filing on October 10, 2024 in Case No. U-21510. The Commission approved the capital spending for DTE Gas Company's portion of the interconnect in its order in Case No. U-21291 on November 7, 2024. The Company's capital expenditures for this project were $53,000 in 2023, and are projected to be $1,161,000 in 2024, $4,466,000 for the 10 months ending October 31, 2025, and $45,000

for the 12 months ending October 31, 2026. These expenditures are included in the Pipeline & Other Installations/ Modifications expenditures discussed above.

B. DELIVERABILITY BASE FIELD MEASUREMENT PROGRAM

Q. Please describe the Deliverability Base Field Measurement Program investments.

A. The Deliverability Base Field Measurement Program is essential to ensure accurate gas quality and measurement. Exhibit A-61 (MPG-5), line 3, identifies the total capital expenditures for the Deliverability Base Field Measurement Program. The capital expenditures for this program were $5,319,000 in 2023, and are projected to be $6,774,000 in 2024, $10,255,000 for the 10 months ending October 31, 2025, and $19,890,000 for the 12 months ending October 31, 2026. Field measurement projects are associated with remote gas measurement equipment monitoring, gas volume calculations, gas transmission metering, Transport Metering Stations ("TMS"), Interstate Interconnection sites, gas quality improvement and processing, gas sampling systems, and other ancillary equipment. These investments directly impact the Company's ability to conform to the MPSC technical standard requirements concerning natural gas quality, measurement accuracy, and Lost and Unaccounted For ("LAUF") gas. Additional projects in this program include measurement equipment upgrades that allow for improvements in American Gas Association volume calculation algorithms, fuel usage report automation, and transducer replacements. The placement of measurement facilities and equipment at appropriate locations can assist in reducing LAUF gas volumes and improve gas quality monitoring. For additional information on LAUF, please see the direct testimony of Company witness Timothy K. Joyce.

Q. Are there any other activities involved in the Deliverability Base Field Measurement Program?

A. Yes. The Deliverability Base Field Measurement Program also involves the installation of meter facilities to validate delivery volumes from interstate suppliers. These projects help improve measurement accuracy of volumes received. The Company is also installing gas quality and gas processing equipment such as chromatographs and water and hydrogen sulfide analyzers to verify gas received from suppliers or withdrawn from storage meets the requirements of pipeline quality gas in accordance with regulatory requirements. The Company is also planning to construct the Williamston Transmission Meter Proving, Testing, and Development Station in the test year. This station will allow a testing environment for gas transmission measurement technology to comply with API-1164, which requires any new protocol, application, or software proposed to be added to the Supervisory Control and Data Acquisition ("SCADA") network should be run in a test-bed or development environment to evaluate the potential for impairing the performance of the SCADA system. Further, the Transportation Security Administration ("TSA") requires the management of software/credentials on measurement devices and a physical testing laboratory with functional versions of all equipment subject to hardware/firmware upgrades to enable testing/validation of firmware in a controlled/non-production environment. The Company currently does not have a test environment for transmission meters or gas analytical equipment.

Major projects included in this filing include:

- Chelsea Meter Replacement. Project year 2023;
- Summerton Road Gas Quality, valve replacement and metering upgrades. Project year 2023;

- White Pigeon 1200A Meter Installation. Project year 2024;
- Lahser USM Installation. Project year 2025;
- Perry Morrice USM Installation. Project year 2025;
- Laingsburg LN 400 Meter Installation. Project year 2025;
- Grand Blanc LN 500 Meter Installation. Project year 2025;
- Rose Center City Gate Meter Replacement. Project year 2026;
- Northville Line 1200A Meter Installation. Project year 2026;
- Chrysler Tech Meter Upgrade. Project year 2026;
- SCADA Gas Quality Hydraulic Modeling. Project year 2026;
- Eureka City Gate Meter Upgrade. Pre-engineering 2026 and Project year 2027;
- Williamston City Gate Chromatograph Upgrade. Pre-engineering 2026 and Project year 2027;
- Winterfield 12 Chromatograph Upgrade. Pre-engineering 2026 and Project year 2027; and
- Ovid Chromatograph Upgrade. Pre-engineering 2026 and Project year 2027.

C. DELIVERABILITY BASE PIPELINE PROGRAM

Q. Please explain the Deliverability Base Pipeline expenditures.

A. The Deliverability Base Pipeline expenditures support maintaining operations in accordance with the Michigan Gas Safety Standards ("MGSS"). Types of projects include: (i) the replacement of valves, and if necessary, the associated valve operators, when inspection determines that the valves no longer perform as needed, which may mean valves no longer turn or they may not fully seal off the flow of gas (MGSS Rules 192.145, 192.150, 192.179); (ii) the replacement of piping due to MAOP revisions identified as a result of class location changes (49 CFR 192.5 and 192.611); (iii) construction of new sectionalizing valves and tap valves to improve system deliverability, and help meet valve

spacing requirements defined by 49 CFR 192.179; (iv) reconfiguration of tap piping (i.e., laterals) and associated valving upstream of city gate facilities as companion projects to city gate rebuilds; and (v) installation or retirement of pipeline taps to TMS facilities being attached to the Company's system. Exhibit A-61 (MPG-5), line 4 identifies the total capital expenditures for the Deliverability Base Pipeline Program. The capital expenditures for this program were $18,757,000 in 2023, and are projected to be $18,173,000 in 2024, $19,403,000 for the 10 months ending October 31, 2025, and $25,023,000 for the 12 months ending October 31, 2026.

Q. Please explain why the Deliverability Base Pipeline expenditures have increased in recent years.

A. The Deliverability Base Pipeline expenditures have increased from historical levels due to a number of factors. In 2019, the Company began conducting annual aerial surveys to enhance the GIS data set to provide more accurate building data along with more accurate occupancy data. There have been a number of class location changes indicated by the aerial survey. Per 49 CFR 192.611, these are segments of pipeline that need to be replaced within 24 months of the change in class location in order to operate the pipeline under the published MAOP. These segment replacements are included in the projection for this program.

Secondly, the Company began conducting annual system wide valve spacing studies in 2021 that review each Transmission Pipeline segment against the current class location to determine if the pipeline segments are in compliance with 49 CFR 192.179. These studies identify the valve(s) required to be compliant with 49 CFR 192.179.

D. REGULATOR STATIONS - DISTRIBUTION

Q. Please describe the regulator station investments.

A. Distribution regulator stations reduce pressure supplied from a higher pressure distribution system to another with a lower pressure distribution system. For example, a regulator station could be used to supply a medium pressure (60 psig MAOP) system from a high pressure system (400 psig MAOP). Exhibit A-61 (MPG-5), line 5, identifies the total capital expenditures for the Regulator Station Program. The capital expenditures for this program were $36,262,000 in 2023, and are projected to be $45,690,000 in 2024, $36,039,000 for the 10 months ending October 31, 2025, and $47,274,000 for the 12 months ending October 31, 2026. The scope of the expenditures in this program is aimed at maintaining the integrity of 648 regulator stations. Additional benefit is realized by the modernization of the fleet of regulator station through the reduction of unintended methane emissions. The Company's regulator station installation plan is further described in Section IV.D.6 of the Company's NGDP, Exhibit A-42 (NPD-1), sponsored by Company witness Dreisig. The Company currently has 94 odorizers, which are considered distribution assets funded as part of this program as well, despite the fact that they are often co-located at city gate sites. These odorizers add odor to the downstream gas systems, which is a critical safety element and is required by code (49 CFR 192.625). Planned projects, location, and project type are listed below. This program also funds emergent issues, as well as SCADA installations, retrofitting of existing gas heaters with modern burner management systems ("BMS"), installation of slam-shut overpressure protection devices and electrical improvements at regulator stations. Investments being made to regulator stations improve employee safety and ergonomics. Regulator stations located in

pits may be difficult to enter and pose risk for operators. These projects are selected based on discussions with subject matter experts and major stakeholders, which include Operations and Engineering, but are also based on asset performance and age of the facility. The major projects in this filing include:

2023

- Verlinden & Shiawassee (Rebuild -Lansing);
- Montrose & Ridgeway (Rebuild – Mount Morris Twp);
- Riverside Dr. (Rebuild – Ionia);
- 21st & Jefferson (Rebuild – Bay City);
- Columbus & Trumbull (Rebuild – Bay City), Functional replacement of 10th & Trumbull;
- Cedar Lake (Rebuild – Day Twp);
- Marshall-Butterfield (Rebuild – Olivet);
- Chicago & Ballenger (Rebuild – Flint); and
- St. Clair Line 1060 distribution odorizer (Rebuild – Ira).

2024

- 21 Mile & Romeo Plank Rd. (Rebuild – Macomb Twp);
- Selfridge – Rosso Hwy. (Rebuild – Mt. Clemens);
- Ithaca Reg Station (Rebuild – Ithaca);
- State & Hemmeter (Rebuild – Saginaw);
- Grand River & Mechanic (Rebuild – Williamston);
- Lake Lansing & Rutherford (Rebuild – East Lansing);
- Attica & Lake Pleasant (Rebuild – Attica Twp); and
- Plainwell Valve Site Odorizer (Rebuild – Plainwell).

2025

- Hotchkiss & M-84 (Rebuild – Bay City);
- Poseyville (Rebuild – Midland);
- Center & Boltwood (Rebuild – Hastings);
- Hogsback & Pryor (Rebuild – Mason);
- Sheridan & Lansing (Rebuild – Gaines Twp.);
- Silver Lake & Dixie (Rebuild – Waterford Twp.);
- Gardner & 7 Mile (Rebuild – Northville); and
- Clintonia Rd. Valve Site Odorizer (Rebuild – Danby Twp.)

2026

- Pitcher & Lovell (Rebuild – Kalamazoo)
- Shepherd & Horatio (Rebuild – Charlotte)
- Sohn Rd. Regulator St. (Rebuild – Vassar)
- Corunna Ave. Regulator St. (Rebuild – Corunna)
- Corunna & M-71 (Rebuild – Corunna)
- Oakland & Sarasota (Rebuild – Pontiac)
- Ruth & Atwater (Rebuild – Ruth)
- Central Odorant Operations Hub (Odorant storge facility – Mid-Michigan).

E. T&S CITY GATES

Q. Please further describe the T&S City Gate investments.

A. City gate stations are the delineation point between the transmission and distribution systems. Gas pressure is reduced to distribution pressure, often 400 psig or less, through pressure regulation. Over-pressure protection, including relief valves, monitor regulators, or emergency shutdown valves (ESD) are installed at these locations to ensure a safe limit

to pressure in the distribution system exists. Odorizer stations are often installed at city gates; although these are distribution assets, they are co-located due to Federal code requirements (49 CFR 192.625) to odorize distribution systems. Odorizers are funded in the Regulator Station Program unless they are installed as part of a complete city gate rebuild. Exhibit A-61 (MPG-5), line 6, identifies the total capital expenditures for the T&S City Gate Program. The capital expenditures for this program were $31,320,000 in 2023, and are projected to be $52,913,000 in 2024, $47,469,000 for the 10 months ending October 31, 2025, and $58,991,000 for the 12 months ending October 31, 2026. The scope of the city gate program allows for the rebuilding or other improvements to existing city gate facilities to ensure system reliability and in response to increased customer load demands. City gate stations allow for certain system safety controls during critical system incidents. City gates can have set pressures lowered or increased to restrict flow into the distribution system, allowing for a greater degree of security, redundancy, and resiliency. Valves, including installation of over pressure protection such as an Emergency Shut-Down Valve ("ESD"), can also be closed to restrict delivery as a mitigation if serious situations develop and to prevent an MAOP exceedance. The Company has developed a city gate work plan as outlined in Section IV.C.2 of the Company's NGDP, Exhibit A-42 (NPD-1). As identified in the NGDP, many city gates are 40 to 50 years old. This makes it challenging to acquire parts and rebuild material for the critical equipment located within the city gate. These projects are selected based on discussions with subject matter experts and major stakeholders, which include Operations and Engineering, but are also based on asset performance and age of the facility. This program also includes expenditures for heater and separator reliability projects. Additionally, this program funds remote terminal

units ("RTU") and electrical improvements at transmission sites, which include replacing or updating RTUs, safety measures associated with lighting, gas detection, or security, and other modernization electrical and instrumentation efforts. Obsolete programming logic controllers also require replacement due to being unsupported and reaching the end of their manufactured recommended life. Many of the City Gates contain this legacy equipment which will need to be updated to modern equipment to prevent downtime in the event of a failure. As emergent projects arise, priority is given to the most important to help ensure safety and reliability, which can result in deferring a planned project. The major city gate projects in this filing include:

2023

- Akron City Gate (Rebuild - Akron);
- Galesburg City Gate (Rebuild – Galesburg);
- Kalamazoo – M Ave City Gate (Rebuild - Kalamazoo); and
- Pontiac Walton ESD (Auburn Hills).

2024

- Excelsior City Gate (Pipe install and City Gate Retirement - Excelsior);
- Orion City Gate (Rebuild - Lake Orion);
- Leonard-Lakeville City Gate (Rebuild – Leonard);
- Blissfield Panhandle Eastern Pipeline ("PEPL") City Gate (Rebuild - Blissfield);
- Dorr City Gate (Partial Rebuild & Modernization - Dorr);
- Jackson Park Rd City Gate (ESD Installation & Electrical Upgrade) - Jackson); and

- Laingsburg City Gate (ESD Installation & Electrical Upgrade - Laingsburg) ;

2025

- Bancroft City Gate (Rebuild - Morrice);
- Lahser City Gate (ESD Installation & Electrical Upgrade - Beverly Hills);
- Flint Torrey City Gate (Rebuild - Flint);
- Macomb City Gate (ESD Installation & Electrical Upgrade - Macomb)
- Hanover Horton City Gate (Rebuild);
- Jackson Hart PEPL City Gate (Rebuild);
- Highland City Gate and odorizer (Rebuild); and
- Overisel Compression (Electrical Upgrade)

2026

- Novi-Wixom City Gate (ESD Installation and modernization);
- Spring Arbor PEPL City Gate (Rebuild);
- Flint CG Irish Rd City Gate;
- Dixie Waterford (ESD Installation & Electrical Upgrade);
- Climax City Gate (Rebuild);
- South Lyon – Whitmore Lake City Gate (Rebuild);
- Mendon Leonidas City Gate (Rebuild); and,
- Northville Compression (Electrical Upgrade)

F. MISCELLANEOUS TRANSMISSION AND COMPRESSION

Q. Please explain the Miscellaneous Transmission and Compression Expenditures shown on line 2 of Exhibit A-61 (MPG-5).

A. This line represents legacy expenditures in programs no longer used, and final settlement costs for projects as they are closed out. In 2023 and 2024, the expenditures are for legacy program costs related to measurement and regulation projects.

Q. Are there contingency costs included in these capital expenditures?

A. No. Although it is a common and prudent practice to include project contingency costs for these types of projects, and is recognized as an accepted Project Management practice, especially when contingency covers the expansion of work approved, contingency costs have not been included in these projections. While contingency costs are a real item in a project estimate, like any other cost, and should be included in estimates of major projects, due to past Commission orders concerning the inclusion of project contingency, the Company has not included those costs in this filing.

Q. Please describe Exhibit A-63 (MPG-7).

A. Exhibit A-63 (MPG-7), in accordance with Attachment 11 to the filing requirements prescribed in Case No. U-18238, provides the variances in the capital program amounts for the distribution and transmission programs, which I sponsored in the Company's most recent general gas rate case, Case No. U-21490.

Q. Can you explain why columns (c), (d), (e), and (f) of Exhibit A-63 (MPG-7), do not contain any data?

A. Yes, the information for column (c), the "Last Rate Case Approved Spending Plan Case No. U-21490," cannot be provided because Case No. U-21490 resulted in a settlement

agreement that did not specifically state approved capital spending amounts for the programs I am supporting. Thus, column (c), the "Last Approved Spending Plan" cannot be calculated. Since there is no data to display in column (c), the information for columns (e) and (f) that seek information concerning the variances from (c), cannot be completed. As for the information for column (d), the "Actual Spending in the Test Year," cannot be completed as the test year in Case No. U-21490, which was the 12 months ending September 30, 2025, is a time period that has yet to transpire as of the filing of this case.

Q. Can you summarize your direct testimony?

A. Yes. The three programs described in my direct testimony span the major areas of Gas Transmission and Distribution operations. These programs eliminate depth of cover issues and physical conflicts with other utilities to ensure continued safe operation, ensure MAOP verification and remediation of the Company's transmission pipelines, and address needed increases in transmission pipeline capacity, all of which help to ensure adequate capacity and deliverability throughout the system. These investments will help the Company meet its objectives of supplying safe, reliable, affordable, and clean energy to customers as described in the NGDP.

Q. Does this complete your direct testimony?

A. Yes, it does.

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

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

REVISED DIRECT TESTIMONY

OF

JAMES P. PNACEK, JR.

ON BEHALF OF

CONSUMERS ENERGY COMPANY

December 2024

Q. Please state your name and business address.

A. My name is James P. Pnacek, Jr., and my business address is 1945 West Parnall Road, Jackson, Michigan 49201.

Q. By whom are you employed and in what capacity?

A. I am employed by Consumers Energy Company ("Consumers Energy" or the "Company") as a Principal Strategy Analyst.

Q. What are your responsibilities as Principal Strategy Analyst?

A. In addition to being a rate case witness, I am responsible for performance-based and Lean initiatives. I support the Company's Gas Strategy, which includes the development, recommendation, and administration of the Natural Gas Delivery Plan ("NGDP").

Q. Please describe your educational background.

A. I received a Bachelor of Science degree, with Honors, in Mechanical Engineering from Michigan State University in 1992.

Q. Please describe your business experience.

A. I joined Consumers Energy in 1992 as a Graduate Engineer in the Natural Gas Compression Department, where I was responsible for providing project management and operational support to the Company's seven compressor stations. I transferred to the St. Clair Compressor Station in 1996, where I supervised operations and maintenance employees, and had responsibility for operating and maintaining the Station. In 1998, I joined the Gas Operations Technical Support Department where I was responsible for the Gas Transmission and Storage capital budget and prioritization of the capital projects. In 2001, I joined the Gas Engineering, Regulatory, and Operating Services - Codes and Standards Group.

In this position, I was Chairman of the Gas Transmission and Storage Standards Committee, responsible for maintaining the Michigan Gas Safety Code-based standards and addressing Michigan Gas Safety Code compliance questions. In 2005, I transferred to the Electric Generation Operations Department. In this position, I was responsible for implementing and managing a Health and Safety Compliance program for Consumers Energy's electric generating plants. In 2008, I joined the Gas System and Operations Planning section of Gas Management Services and was responsible for the Gas Cost Recovery ("GCR") purchase recommendations and management of Storage Field Inventory. I assumed my current duties and responsibilities in Gas Strategy in September 2021.

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

A. Yes. I have filed testimony and/or testified in GCR Reconciliation Case Nos. U-16924-R, U-17133-R, U-17334-R, U-17693-R, U-17943-R, U-20075, U-20209, U-20233, and U-20542. I have also filed testimony in Gas Rate Case No. U-21490 and End-Use Transportation proceeding in Case No. U-17900.

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

A. My direct testimony provides a detailed description of the projected Operating and Maintenance ("O&M") expenses for the Company's Gas Operations Division that are necessary to allow the Company to meet public safety, compliance, and operating requirements, while delivering an excellent level of service to customers. I will explain the Company's Gas Operations Division O&M expenses for the projected test year 12 months ending October 31, 2026, to be referred to as "test year" or "2025 – 2026 Test year" in my

testimony. My direct testimony is divided into two parts: (i) Gas Operations O&M expenses and (ii) Information Technology ("IT") projects.

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

A. Yes. I am sponsoring the following exhibits:

Exhibit A-86 (JPP-1)	Summary of Actual & Projected O&M Expenses: Operations, Maintenance & Metering, Field Services, Other Operations;
Exhibit A-87 (JPP-2)	Summary of Actual & Projected O&M Expenses: Operations, Maintenance & Metering Programs;
Exhibit A-88 (JPP-3)	Summary of Actual & Projected O&M Expenses: Field Operations Services; and
Exhibit A-89 (JPP-4)	Summary of Actual & Projected O&M Expenses: Other Operations.

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

A. Yes.

GAS OPERATIONS O&M EXPENSES

Q. Please describe the Gas Operations Division.

A. The Gas Operations Division is committed to meeting the needs of Consumers Energy's natural gas customers through the delivery of services in a safe, reliable, cost-effective, and timely manner. The division manages the routine, ongoing customer-facing operations and maintenance of the Company's distribution and transmission systems. The O&M expenses for Gas Compression will be covered in Company witness Timothy K. Joyce's testimony. The Gas Operations Division manages the O&M programs described more fully below.

Q. What are the major O&M programs that are managed within the Gas Operations Division?

A. The four major O&M programs within the Gas Operations Division are as follows:

1. Operations, Maintenance, and Metering
2. Field Operations Services
3. Work Management and Customer Delivery
4. Operations Management

Q. Were there any changes to the major O&M programs within the Gas Operations Division for this case?

A. Yes. The Operations Performance program that was formerly part of the Gas Operations Division testimony was reorganized with a portion moving to the IT and to Lean organizations. However, a new program called Work Management and Customer Delivery was created from the remaining Operations Performance organization, and that portion of the former organization remains in my testimony.

Q. Please define and discuss the term Standard Labor Rate ("SLR") as it is used within the context of your testimony.

A. The SLR is a cost allocation mechanism used by the Company to assign a direct labor dollar value to an individual work order. A direct labor dollar value is calculated starting with the direct labor hours spent completing a work order, then multiplying those hours by the SLR. The SLR represents an average payroll cost that considers regular time payroll costs, overtime payroll costs, and paid absence payroll costs. The specific dollar value of an SLR is reviewed periodically to update the rate for any changes in regular time, overtime, and paid absence payroll costs. For forecasts developed for future years, SLRs generally reflect current payroll costs levels with an annual forward-looking adjustment of 3% per year, which is consistent with the contractual labor agreement between the Company and its operating employees' union.

Q. Please define and discuss the term Indirect Labor as it is used within the context of your testimony.

A. Indirect Labor is a cost allocation mechanism used by the Company to assign payroll costs to a work order for periods of operating employee working time not directly attributed to a specific work order. Examples of these indirect working time costs include beginning of day or end of day administrative tasks, travel time between job sites, and meetings. Indirect Labor costs are allocated to specific work orders using indirect labor loading rates. These loading rates vary across different operating employee work groups and are reviewed periodically to manage any variances between actual indirect labor costs incurred and the amounts applied to work orders.

Q. Please describe how vehicle costs are generally applied to a work order.

A. Vehicle costs are allocated to work orders using vehicle loading rates, which are applied to the Direct Labor costs of a work order. Vehicle loading rates will vary between the various operating employee work groups, and these rates are reviewed periodically to manage any variances between actual vehicle costs and the amounts applied to work orders.

Q. How has the Company projected its Gas Operations Division O&M expenses for the test year?

A. The Company has identified the O&M expenses for the test year that are necessary to meet public safety and customer service requirements. The total amount of Gas Operations O&M expenses for which I am requesting recovery during this time period is $133,635,000 as shown on Exhibit A-86 (JPP-1), line 6, column (e). These forecasts reflect the Company's expectations for work activity as measured in units and/or orders, resource

requirements as measured by jobsite hours for each program, and the associated expense amount for each program.

Q. Please explain the source of the 2023 actual and derivation of the projected test year O&M expenses for the Gas Operations expenses shown on Exhibit A-86 (JPP-1).

A. The 2023 actual O&M expense amount of $111,299,000 as shown on Exhibit A-86 (JPP-1), line 6, column (b), for Gas Operations is derived from Consumers Energy's internal records. The projected test year expense levels for the Gas Operations Division programs were derived as explained below for each program. Unless otherwise noted, the program projections for the test year were calculated using a weighted average of the 2025 and 2026 forecast amounts, which reflect the Company's recent historical experience of monthly O&M expenses for individual programs.

The projected test year expense level of $133,635,000 will allow the Company to meet customer service, deliverability, and safety requirements.

Q. Please explain the merit increase and inflation calculations that have been provided in Exhibit A-87 (JPP-2), page 2; Exhibit A-88 (JPP-3), page 2; and Exhibit A-89 (JPP-4), page 2.

A. These specific pages of my exhibits present the anticipated amount of O&M expense increases that can be expected by applying either an inflation rate or a merit increase rate, or both, to historical O&M expense. Inflation was not used to determine the program funding in this case, however the following is an explanation of the exhibit.

Column (b), which is titled "Actual 12 Mos Ending Dec 31, 2023" shows the historical O&M expense. Column (c), entitled "Base O&M for Merit and Inflation 12 Mos Ending Dec 31, 2023" shows the amount of historical expense the Company believes

should be used as the base for calculating merit and inflation adjustments. The Company has excluded Operating Maintenance & Construction ("OM&C") employee direct labor and indirect labor from the base for merit and inflation calculations because the future increases in those costs reflect the current working agreement the Company has with its OM&C workforce. Columns (d), (f), and (h) show the merit and inflation amounts calculated for each respective period. Increases or decreases that have been projected using other methods, such as changes in OM&C labor rates applied to work orders or other workload changes, are included in column (i). Column (j) is the projected test year O&M and is the sum of columns (b), (d), (f), (h), and (i); column (j) is aligned with the Company's projected expenses for each sub-program for the test year, as shown on page 1 of my respective exhibits.

The inflation values in Exhibit A-87 (JPP-2), page 2; Exhibit A-88 (JPP-3), page 2; and Exhibit A-89 (JPP-4), page 2 were all set to 0.0% for 2024, 2025, and the test year. Therefore, column (i) represents the increase (or decrease) in O&M expenses when comparing the test year to 2023 Actuals. The projected increases from 2023 to the test year are explained for each sub-program as part of my direct testimony.

Q. Are there any Employee Incentive Compensation Program ("EICP") O&M expenses included in your exhibits?

A. No, there are not. The direct testimony and exhibits of Company witness Amy M. Conrad contain the Gas Operations Division EICP O&M expenses.

Q. Are there any Injuries and Damages expenses included in your exhibits?

A. No, there are not. The direct testimony and exhibits of Company witness Matthew J. Foster contain the Gas Operations Division Injuries and Damages expenses.

Proposed Leak Detection and Repair Regulations

Q. Does the Company anticipate any new regulations from the Pipeline and Hazardous Materials Safety Administration ("PHMSA") during the test year?

A. Yes. The Company anticipates that PHMSA will adopt proposed regulatory amendments that implement congressional mandates in the *Protecting the Infrastructure of Pipelines and Enhancing Safety Act of 2020* ("PIPES Act"). The objective of the PIPES Act is to reduce methane emissions from new and existing gas transmission pipelines, distribution pipelines, and underground natural gas storage facilities. PHMSA's proposed regulatory amendments are otherwise referred to as Leak Detection and Repair ("LDAR") rules.

Among the amendments for part 192 Regulated Gas Pipelines are:

- Strengthened leakage surveys, and patrolling requirements,
- Performance standards for advanced leak detection programs,
- Modified leak grading and repair criteria with mandatory repair timelines,
- Requirements for mitigation of emissions from blowdowns,
- Pressure relief device design, configuration, and maintenance requirements, and
- Clarified requirements for investigating failures.

Finally, PHMSA expanded reporting requirements for operators of all gas pipeline facilities within DOT's (Department of Transportation) authority.

More specifically, these mandated requirements will require the Company to perform the following tasks that will incur additional O&M expense:

- Increase the frequency of the periodic Leak Surveys the Company currently performs,
- Increase the frequency of Line Patrols the Company currently performs,

- Accelerate timeline for Leak Repairs,
- Perform Post Repair Inspection and any necessary remediation within the mandated period, and
- Conduct Environmental Change Surveys to investigate known leaks.

The Company expects the rule to be published by January 2025, with an anticipated effective date six months later. The Company anticipates that the LDAR rules will include a phase in period, with full compliance with these requirements expected in January 2028.

Q. Please describe the PHMSA's LDAR requirements the Company is expecting to be required to comply with during the test year.

A. PHMSA proposes to require operators to complete repairs of grade 2 leaks known to exist on or before July 2025, the Company's anticipated effective date of the rule, within one year from the date of publication of the final rule. The expected compliance date with this portion of the rule is January 2026. Also, PHMSA proposes to require a grade 3 leak known to exist on or before the effective date of the rule be repaired within three years from the date of publication of the final rule. The expected compliance date with this portion of the rule is January 2028. In addition, PHMSA proposes to require operators to complete repairs of any leak on a gas transmission line in a High Consequence Area (HCA), Class 3 or Class 4 location known to exist on or before the effective date of the rule within one year from the date of publication of the final rule. The expected compliance date with this portion of the rule is January 2026.

Q. Please describe the Company plan to comply with the leak backlog requirements of the proposed rule.

A. Based on the Company's understanding of the compliance timeline of the regulation, the Company will not request full compliance funding in this case for O&M expenses related

to the LDAR rule set forth in the Notice of Proposed Rulemaking and as modified from the Gas Pipeline Advisory Committee ("GPAC") LDAR meetings. However, based on the proposed known leak elimination requirements of the rule, considering the benefits to public safety, and the Company's desire to further reduce risk, the Company will ask for funding for this portion of the LDAR requirements. The Company plans to eliminate the backlog of known leaks on the system at an accelerated rate as part of the work plan, regardless of the timing of the LDAR rule publication. The Company plans to spend $1,300,000 to address the anticipated leak backlog on the system for the test year in the Leak Survey and Repair program section of my testimony. The Company realizes the final rule has not yet been published, and substantive changes could be made to the rule resulting in meaningful changes to the costs projected in this case. Therefore, the Company is requesting the Commission approve the ability to defer any test year O&M expense that occurs as a result of the requirements of the final rule that are above the requested funding in this case. It is important to note the regulation is expected to be published at or shortly after the filing of this case, therefore the Company expects to have additional data available during the discovery phase of this case.

Operations, Maintenance, and Metering

Q. Please describe the O&M expenses related to the Operations, Maintenance, and Metering sub-programs shown on Exhibit A-87 (JPP-2).

A. The Operations, Maintenance, and Metering sub-programs include the operation and maintenance of the Transmission and Distribution system. Major assets in these sub-programs include mains, services, pipelines, storage fields, meters, city gates, valves, and regulators. The sub-programs also include leak survey and repair, damage repair, odor

response, meter reading, meter services, right of way clearing, and staking. The Operations, Maintenance, and Metering sub-programs include several customer demand programs related to the front-line operations of the natural gas service and natural gas distribution areas of the Company. Gas Transmission employees focus on safely maintaining the Company's above and underground transmission system (pipelines, meters, regulators, city gates, and storage fields).

Gas Distribution employees primarily focus on safely maintaining the Company's underground facilities (gas mains and services), meter stands, and regulation facilities. Gas service employees focus on safely maintaining the Company's above ground facilities (such as meters and meter piping). Each sub-program is more fully described below.

Distribution Cathodic Protection

Q. Please describe the O&M expenses related to the Distribution Cathodic Protection sub-program.

A. This program is associated with regulatory-required corrosion control activities of the gas distribution system. Cathodic protection reduces the corrosion on steel main that could lead to natural gas leaks over time. The Company is projecting test year spending of $2,915,394 on Distribution Cathodic Protection.

Q. Please provide a breakdown of the work being performed in the test year for the Distribution Cathodic Protection sub-program.

A. This program includes O&M expenses for annual pipe-to-soil readings, bi-monthly rectifier and foreign bond readings, interference testing, diagnosis of sectors not meeting cathodic protection criteria, and repairs to downed sectors to meet code requirements. The Company currently has 49,447 test points read annually for pipe-to-soil readings, as well as an

additional 1,483 bi-monthly reads at rectifiers and designated bond points. The annual test point reads by Headquarters for this sub-program are summarized in the following table:

Table 1

2025 Annual Reads Per Headquarters	
Work Headquarters	**Annual Read at Designated Test Points Complete 100% of These Reads Impacts Year 2026**
Adrian	429
Alma	945
Bad Axe	617
Bay City	1,996
Cadillac	94
Flint	4,910
Greenville	606
Groveland	2,715
Hastings	575
Howell	1,061
Jackson	1,686
Kalamazoo	3,375
Lansing	3,795
Livonia	6,258
Macomb	7,945
Marshall	224
Midland	1,277
Owosso	905
Royal Oak	6,957
Saginaw	3,077
Total	49,447

For the test year, the Company will have approximately 49,447 test points to read for pipe-to-soil readings. The Company's test points vary from year to year as it installs new plastic main, which changes the design of cathodic protection for that section of pipeline.

For the test year, the Company will have 1,438 bi-monthly reads at rectifiers and designated bond points. The overall number of reads has reduced as the Company installs remote monitoring units ("RMUs") that reduced the bi-monthly requirements during the months of January, May, July, September, and November.

The bi-monthly reads by Headquarters for this sub-program are summarized in the following table:

Table 2

2025 Bi-monthly Reads (Includes Rectifiers and Bond Points)							
Work Headquarters	**Jan**	**Mar**	**May**	**Jul**	**Sep**	**Nov**	**Total**
Adrian	0	13	0	0	0	0	
Alma	7	41	7	7	7	7	
Bad Axe	0	14	0	0	0	0	
Bay City	2	41	2	2	2	2	
Cadillac	0	10	0	0	0	0	
Flint	2	87	2	2	2	2	
Greenville	0	15	0	0	0	0	
Groveland	6	79	6	6	6	6	
Hastings	2	27	2	2	2	2	
Howell	1	33	1	1	1	1	
Jackson	14	64	14	14	14	14	
Kalamazoo	15	164	15	15	15	15	
Lansing	9	88	9	9	9	9	
Livonia	5	68	5	5	5	5	
Macomb	5	38	5	5	5	5	
Marshall	3	16	3	3	3	3	
Midland	0	31	0	0	0	0	
Owosso	2	29	2	2	2	2	
Royal Oak	15	89	15	15	15	15	
Saginaw	0	51	0	0	0	0	
Total	88	998	88	88	88	88	1,438

In addition to the annual reads, the O&M expenses include dollars to complete three-year atmospheric above grade inspections at 2,103 locations and 120 bridge inspections in 2026. The atmospheric above grade and bridge inspection by Headquarters for this sub-program is summarized in the following table:

Table 3

2025 – 3-Year Inspections Including Contractor Bridge Inspections			
Work Headquarters	**Atmospheric Aboveground Corrosion Inspection (every 3 years) Impacts 2026**	**3-Year Bridge Inspections Impacts 2026**	**Total**
Adrian	22	2	24
Alma	35	0	35
Bad Axe	35	0	35
Bay City	103	0	103
Cadillac	6	0	6
Flint	194	11	205
Greenville	25	2	27
Groveland	62	17	79
Hastings	30	0	30
Howell	47	9	56
Jackson	142	2	144
Kalamazoo	231	4	235
Lansing	204	9	213
Livonia	128	14	142
Macomb	263	18	281
Marshall	20	2	22
Midland	38	0	38
Owosso	61	4	65
Royal Oak	233	24	257
Saginaw	224	2	226
Total	**2,103**	**120**	**2,223**

For the test year, the Company will have approximately 31 bridge locations to complete repairs on, based upon its 2023 bridge inspection results.

The Company anticipates that approximately 2,500 sectors will not meet cathodic protection requirements within the given test year based upon historical trends.

Sectors will not meet criteria for a variety of reasons, including third-party damages to cathodic bond wires, foreign utility crossings that draw cathodic protection voltage away from steel gas mains, and anode/groundbed lifespan deterioration. This historical trend in this sub-program is summarized in the following table:

Table 4

Historical Data 2023 and 2024 Downed Sectors	
2023	**2024 YTD September**
2,217 downed sectors	1,978 downed sectors

In addition to the annual reads, inspections, and diagnostic work, the O&M expenses also include dollars to complete approximately 700 repairs in combinations of coating repair, above and below grade short removal, test wire repairs, rectifier repairs, groundbed repairs, and atmospheric corrosion repairs on service risers. These expenses are projected based on historical information and include the number of annual and bi-monthly survey reads that must be completed each year/month in compliance with regulatory standards.

The historical year costs and projected test year costs for this sub-program are summarized in the following table:

Table 5

Distribution Cathodic Protection Projection Breakdown by Activity Type		
Work Type	**2023 Actual**	**2025-2026 Test year**
Distribution Cathodic Protection – Non-WBS	$220,837	$252,107
Cathodic Protection – Contractor; Material and Other Expenses	$505,839	$577,463
Cathodic Repairs	$198,640	$226,767
Sector Diagnosis	$254,433	$290,460
Annual Pipe to Soil Survey	$1,097,498	$1,252,899
Riser Wraps – Non-Leak Maintenance	$44,268	$50,536
Bi-Monthly Survey	$232,274	$265,163
Total Program	$2,553,789	$2,915,394

Q. What is the basis for determining the $2,915,394 of projected O&M expenses in the test year for this sub-program?

A. Projected test year spending in this sub-program is primarily driven by annual reads, inspections, repairs, reduced contractor utilization, and diagnostic work. The historical and projected activity for Company crews in this sub-program is summarized below in the following table:

Table 6

Distribution Cathodic Protection Units/Orders, Hours & Dollars			
Year (Jan-Dec)	**Units/Orders**	**Hours**	**Program Dollars**
2016	31,705	24,616	$2,377,667
2017	40,664	19,127	$2,783,055
2018	44,794	20,222	$3,762,986
2019	52,924	15,029	$2,477,811
2020	43,146	15,720	$3,190,166
2021	52,355	13,353	$3,140,486
2022	35,514	13,451	$2,677,564
2023	40,443	11,056	$2,553,789
2024 Projected	50,325	11,303	$1,988,742
2025 Projected	49,526	9,274	$1,835,255
2025-2026 Test year	49,874	9,474	$2,915,394

The Company's projection for Distribution Cathodic Protection test year spending is based on a weighted average of the 2025 (3%) and 2026 (97%) forecast amounts, which reflects the Company's historical experience of program expense timing.

Pipeline – Distribution

Q. Please describe the O&M expenses related to the Operations and Maintenance Pipeline – Distribution sub-program.

A. The Operations and Maintenance Pipeline – Distribution sub-program includes multiple activities that ensure safe and reliable delivery of gas to customers' homes. For this sub-program, the Company is projecting test year spending of $11,512,760.

Q. What work is undertaken as part of the Operations and Maintenance Pipeline – Distribution sub-program?

A. This sub-program includes customer-requested work requiring alterations to existing gas mains and services, including new business branch services, meter and service relocations (where the entire service from the main to the meter is not installed or replaced) and replacing risers for installation of new meters. Where the entire service from main to meter is installed or is replaced, the costs become capital and are not included in this program. With respect to the condition of Company assets, the work activities include designated valve repairs, cross bore repairs, inside meter inspection, no-gas investigation and repair, non-leaking maintenance activities such as repairing or replacing lockwing valves to allow emergency shut-offs, replacing mushroomed plastic risers, replacing copper risers due to atmospheric corrosion, lowering main or service facilities if grade has changed, installing and pumping drips on the standard (low) pressure system thereby helping to alleviate water infiltration and freezing of service lines and meters, and property restoration costs. This sub-program also includes site checking activities to ensure customer locations are ready for work and improve efficiency and on-time delivery by avoiding unnecessary field trips by distribution crews. Site check activities additionally include confirming all jobsite

requirements have been met, such as underground facility staking, sewer lead locations, final grade established, and site readiness prior to the arrival of distribution construction crews. In addition, electric usage utility costs for the gas distribution regulation facilities and the inspections at the Huron Compressor Station are both included in this sub-program. The historical year costs and projected test year costs for this program are summarized in the following table:

Table 7

Operation & Maintenance – Distribution Projection Breakdown by Activity Type		
Work Type	**2023 Actual**	**2025-2026 Test year**
Material Condition Emergent	$781,582	$1,008,223
Material Condition	$3,630,493	$4,683,256
Huron Compressor Station	$116,506	$150,290
Main & Services Alterations	$1,858,802	$2,397,813
Property Restoration	$1,036,362	$1,336,884
Site Checks	$225,909	$291,417
Pre-fabrication Costs	$738,160	$952,210
Other, including Non-WBS, Utilities	$536,961	$692,667
Total Program	$8,924,773	$11,512,760

Q. What is the basis for determining the $11,512,760 of projected O&M expenses in the test year?

A. Projected test year spending adjustments are driven by the following changes in the workplans:

- Adding the no-gas investigation and repair work,
- Increased number of non-leak maintenance (NLM) orders based on the rotation of area being surveyed and improved training to ensure all NLMs are identified,
- Alignment with customer-requested workload,

- Managing third-party contractor costs of performing this work, such as temporary traffic control and hydrovac usage.

The 2024 and 2025 projections anticipate increases to workload completion and increased labor rates for Distribution and Service employees.

Distribution and Service worker hourly standard labor rates are expected to be:

Table 8

	Distribution				Service			
	Standard Labor Rates	Indirect Labor Rates	Vehicle Rates	Total Rate	Standard Labor Rates	Indirect Labor Rates	Vehicle Rates	Total Rate
2023	$69.86	$37.72	$43.31	$150.90	$70.23	$105.35	$25.99	$201.56
2024	$73.41	$39.64	$33.77	$146.82	$73.80	$98.15	$22.14	$194.09
2025	$75.58	$40.81	$40.81	$157.21	$75.63	$102.86	$22.69	$201.18
2026	$78.47	$42.37	$42.37	$163.22	$78.52	$106.79	$23.56	$208.86

This historical and projected activity in this sub-program is summarized in the following table:

Table 9

Operations & Maintenance – Distribution Units/Orders, Hours & Dollars			
Year (Jan-Dec)	**Units/Orders**	**Hours**	**Dollars**
2016	10,612	37,298	$5,787,716
2017	9,415	40,679	$6,878,971
2018	10,023	43,952	$8,241,128
2019	10,722	40,430	$7,998,681
2020	9,064	43,157	$7,850,034
2021	13,755	59,207	$11,721,014
2022	9,983	47,774	$10,531,290
2023	9,370	40,741	$8,924,773
2024 Projected	17,132	45,017	$10,814,580
2025 Projected	14,708	41,450	$9,066,529
2025-2026 Test year	16,703	53,172	$11,512,760

The Company's projection for the Operations and Maintenance Pipeline – Distribution sub-program test year spending is a weighted average of the 2025 (7%) and

2026 (93%) forecast amounts, which reflect the Company's historical experience of program expense timing.

Pipeline – Transmission

Q. Please describe the O&M expenses related to the Operations and Maintenance Pipeline - Transmission sub-program.

A. The Operations and Maintenance Pipeline - Transmission sub-program includes expenses related to performing:

(a) Code Inspections,

(b) Third-party oversight and staking per MISS DIG 811 Underground Facility Damage Prevention and Safety Public Act 174 ("Act 174") of 2013, ("MISS DIG 811"),

(c) Demand Maintenance,

(d) Preventive Maintenance & Operations,

(e) Restoration/Right-of-Way ("ROW"), and

(f) Miscellaneous Expenses.

This sub-program ensures public safety by maintaining the integrity of the Company's gas transmission pipeline system through inspection and repair of all critical assets to sustain proper operating conditions. Sub-program funding also includes necessary maintenance of valves sites, buildings, fencing, and security systems and structures. For this sub-program, the Company is projecting test year spending of $3,741,356.

Q. Please provide a description of the work activities in the Operations and Maintenance Pipeline - Transmission sub-program.

A. This sub-program includes the following work activity categories.

- Code Inspections include completing Michigan Gas Safety Standards ("MGSS") and Michigan Department of Environment, Great Lakes, and Energy ("EGLE") code inspections associated with pipeline valves, pipe, and

associated assets. This work is generally completed by Company employees and code inspection orders typically include labor and ancillary material costs. Examples of these inspections include vehicle and foot patrol of pipelines, leak survey, valve inspections, Pressure Limiting Device inspections, Remote Control Valve inspection, corrosion inspections, maintenance pigging, and inspection of gas quality equipment, including drip logs and separators that protect pressure regulation and customer metering equipment. One key example is line patrols where, based on class location, the Company patrols the system from one to four times per year to investigate for new dwellings, leaks, and third-party activity. As part of these line patrols, the Company takes appropriate actions to repair equipment and/or remediate in compliance with the MGSS. (MGSS code/standard/section 192.705, 192.706, 192.613, 192.935). This sub-program also includes MGSS required pipeline maintenance cleaning pig runs on five transmission lines that need to be completed annually. These pig runs are coordinated with the Company's Pipeline Integrity Program to avoid duplicate pig runs in the same calendar year. This work is included as part of the Company's Transmission Integrity Management Program.

- The Pipeline Preventative Maintenance and Operations portion of the sub-program involves proactive and necessary inspections that do not fall under code requirements but are necessary for maintaining safe, reliable, and predictable system operations for customers. Such inspections include: (a) instrument calibration; (b) launcher and receiver inspections; (c) vehicle safety inspections; (d) general safety inspections; (e) liquid drip collection; (f) housekeeping; and (g) site maintenance and other general functions.

- The Demand Maintenance portion of the sub-program accounts for labor and materials, to address pipeline assets that require repair due to performance during annual inspections, outages, or other activities. These activities typically include: (a) maintenance of valves, cathodic protection test stations, rectifiers, liquid collection equipment, pipeline markers, metering equipment, communication equipment, calibration equipment, pipe coating, sites, and facilities; (b) leak repairs; (c) ROW access maintenance; (d) third-party damage repairs; and (e) snow plowing.

- The Facilities Locating for Third Parties (MISS DIG 811) portion of the sub-program is primarily comprised of labor hours required to evaluate, locate, stake, and oversee third-party activities near transmission pipelines.

- Non-Work Breakdown Structure ("Non-WBS") portion of the sub-program includes labor, internal departmental chargebacks, contractors, and materials not directly associated with a specific work order. These costs include OM&C travel and meal charges, Company Laboratory labor for equipment calibration, storeroom stock and non-stock material issues, equipment rental charges, storage space rental, electric bills for rectifiers, and other site equipment.

- Contractor Materials, Credits and Other Expenses portion of the sub-program includes Contractor labor, credits, and materials for Code Inspection, Preventive Maintenance & Operations, Demand Maintenance, and Facilities Locating for Third Parties (MISS DIG 811) that are directly associated with a specific work order.

The historical year costs and projected test year costs for this sub-program are summarized in the following table:

Table 10

Operation & Maintenance – Pipeline- Transmission Projection Breakdown by Activity Type		
Work Type	**2023 Actual**	**2025-2026 Test year**
Non-WBS	$710,866	$754,752
Contractor; Materials, Credits and Other Expenses	$392,062	$377,963
Code Inspections	$871,321	$782,592
Preventive Maintenance & Operations	$385,434	$365,210
Demand Maintenance	$380,031	$417,383
Facilities Locating for Third Parties (PA 174)	$1,090,828	$1,043,456
Total Program	$3,830,542	$3,741,356

Q. What is the basis for determining the $3,741,356 of projected O&M expenses in the test year for this sub-program?

A. The Company's projection for the Operations and Maintenance Pipeline – Transmission sub-program test year spending is a weighted average of the 2025 (10%) and 2026 (90%) forecast amounts, which reflect the Company's historical experience of program expense timing. As shown in the table above, projected spending in this sub-program is primarily driven by known hours for regulatory driven code inspections, preventative maintenance, and maintenance pigging activities. Demand maintenance (conditions requiring short-term response), and facility locating for third parties (MISS DIG 811), are projected based on historical trends and anticipated needs. The projected labor hour allocations for Code

Inspections are based on historical time to perform required inspections and maintenance to the assets on the transmission pipeline system.

The projected expenses associated with Facilities Locating for Third Parties (MISS DIG 811) activities are comprised of historical data and projected trends. Historically, ticket volumes have trended down due to a greater volume of tickets being processed in the office, and only actionable tickets being sent to the operational groups.

Based on the trend experienced in 2023 and the current economic growth, ticket volumes and hours are expected to be flat through 2026 (see below table).

Table 11

Miss Digs 811 Tickets and Associated Hours		
Year	**Orders**	**Hours**
2016	12,538	6,119
2017	14,440	7,000
2018	18,412	8,327
2019	20,531	10,181
2020	20,150	10,274
2021	15,931	8,633
2022	9,562	7,801
2023	9,337	8,115
Trend 2024	9,000	8,000
Trend 2025	9,000	8,000
Trend 2026	9,000	8,000

Gas Transmission worker hourly standard labor rates are expected to be:

Table 12

Transmission				
	Standard Labor Rates	**Indirect Labor Rates**	**Vehicle Rates**	**Total Rate**
2023	$69.18	$24.90	$36.67	$130.75
2024	$72.53	$23.93	$34.81	$131.28
2025	$76.37	$26.73	$32.08	$135.17
2026	$79.28	$27.75	$33.30	$140.33

The historical and projected activity in this sub-program is summarized in the following table:

Table 13

Operations–& Maintenance - Pipeline Hours & Dollars		
Year (Jan-Dec)	**Hours**	**Dollars**
2016	24,033	$2,675,390
2017	21,865	$2,131,709
2018	23,556	$2,670,236
2019	26,639	$3,121,709
2020	23,634	$3,012,604
2021	20,676	$3,198,861
2022	21,783	$4,221,974
2023	17,879	$3,830,542
2024 Projected	14,253	$3,456,218
2025 Projected	14,212	$3,017,218
2025-2026 Test year	18,631	$3,741,355

Regulation Distribution

Q. Please describe the O&M expenses related to the Operations and Maintenance - Regulation Distribution sub-program.

A. The Operations and Maintenance - Regulation Distribution sub-program is responsible for delivering safe and reliable gas service pressure to customers. For the test year, the Company is projecting spending $8,496,643 for this sub-program. This program consists of all code compliance requirements for regulation stations and odorant facilities statewide. This includes all required annual inspections, and maintenance and repairs of these facilities. The sub-program ensures gas delivery to customers with a detectible odor required for public safety. Inspection of critical designated valves that isolate sections of the distribution pipeline system during planned outages or emergencies is also included in this sub-program. This is critical for system operations and public safety. The Regulation

Distribution sub-program is responsible for the statewide inspection, maintenance, and repair of:

- 662 Distribution Regulation Stations,
- 1,660 1-inch and larger high-pressure regulation stands,
- 100 Odorant Injection Facilities, and
- 7,270 Designated Pipeline Valves.

The historical year costs and projected test year costs for this sub-program are summarized in the following table:

Table 14

Operation & Maintenance – Regulation Distribution Projection Breakdown by Activity Type		
	2023 Actual	**2025-2026 Test year**
Designated Valves	$1,409,923	$1,420,059
Regulation Inspection	$3,924,357	$3,952,570
Regulation Repairs	$2,425,685	$2,443,123
Vegetation Management	$676,030	$680,891
Total Program	**$8,435,995**	**$8,496,643**

Q. What is the basis for determining the $8,496,643 projected O&M expenses in the test year for this sub-program?

A. To efficiently and safely operate the distribution pipeline system, the Company continues to invest in new regulation facilities (city gates and distribution regulator stations). These investments are sponsored by Company witness Michael P. Griffin. These new or upgraded facilities have additional equipment and technology installed that requires annual inspection and maintenance. Examples include Supervisory Control and Data Acquisition ("SCADA") communication components, transducers, catalytic heaters, gas pipeline filter separators, odorant pump injection systems, additional designated blow-down valves on

Transmission Operated as Distribution pipe ("TOD"), and poly valves as required on all new gas main installed.

The historical and projected activity in this sub-program is summarized in the following table:

Table 15

Operations & Maintenance – Regulation Distribution Units/Orders, Hours & Dollars			
Year (Jan-Dec)	**Units/Orders**	**Hours**	**Dollars**
2016	5,129	41,366	$4,609,086
2017	5,009	38,058	$4,330,964
2018	6,240	40,943	$6,169,182
2019	7,672	40,350	$5,909,548
2020	8,246	42,432	$6,363,894
2021	13,651	43,728	$7,662,838
2022	10,701	52,315	$9,126,940
2023	10,641	47,443	$8,435,995
2024 Projected	12,118	45,774	$8,078,355
2025 Projected	12,785	44,291	$8,048,289
2025-2026 Test year	13,435	45,433	$8,496,643

The projection for the test year is a weighted average of the forecasts for 2025 (9%) and 2026 (91%), which reflects the Company's recent historical experience with the timing of program expenses.

Measurement and Regulation Transmission

Q. Please describe the O&M expenses related to the Operations and Maintenance - Measurement and Regulation Transmission sub-program.

A. The Operations and Maintenance - Measurement and Regulation Transmission sub-program is primarily responsible for gas measurement, pressure control, and gas quality for the Company's transmission system, which feeds the distribution system as well. This work is driven by MGSS, EGLE, Department of Transportation, Federal Energy

Regulatory Commission ("FERC"), PHMSA, Occupational Safety and Health Administration, and Sarbanes Oxley ("SOX") controls. This includes third-party supplies and metering to meet SOX requirements as well as lost and unaccounted fuel custody requirements. This sub-program also includes expenses relating to the inspection and repair of data acquisition systems, metering, pressure control valves and regulators, overpressure protection, odorization, gas quality analyzers, and gas conditioners. These inspections can include piping, regulators, transducers, SCADA, valves, operators, emergency shut down devices, separators, heaters, meters, relief valves, and odorizers. Also included are monitoring and operating gas quality and analysis equipment such as chromatographs, which measure for water (H_20), hydrogen sulfide (H_2S), carbon dioxide (CO_2), oxygen (O_2), and testing for Polychlorinated Biphenyls (PCB). Other expenses include vehicles, maintenance equipment, utility bills, regulatory permits, and general cost to maintain city gate sites, buildings, fencing, and security. This sub-program ensures the safety and compliance of Company gas transmission and distribution pipeline systems through inspection and repair of all critical assets to meet federal, state, and local agencies' regulatory requirements.

Q. Please provide a description of the work activities in the Operations and Maintenance - Measurement and Regulation Transmission sub-program.

A. This sub-program includes the following work activity categories.

- The Demand Maintenance projected expense accounts for labor, material, and contractor supported activities to perform repairs on measurement and regulation assets. These repairs can arise from code inspections or failed equipment that requires immediate or scheduled actions. This activity covers all required emergent work relating to safety or system improvements to ensure the flow of gas and material readiness. Examples include driveway stone and repairs, filters for separators and liquid extraction, building repairs and permitting, painting, brush and tree removal, landscaping, fencing, lighting, RTU repairs, transducer and ultrasonic instrumentation, and required

investigations to respond to gas control alarms, including RTU device communication failures. The additional equipment added to the system results in the increased units.

- The Preventative Maintenance projected expense supports performing proactive and necessary inspections that do not fall under the code requirements but are necessary for maintaining safe, reliable, and predictable system operations. Such inspections include Remote Terminal Unit ("RTU") inspections, instrument calibration, liquid drip collections, pilot filter replacements, winter system operational checks, non-code valve inspections, general site inspections, pressure changes, heater maintenance, orifice plate inspections, painting, and grade work. Additionally, preventative maintenance includes labor hours and material costs to maintain site access and conditions including access drive and site stone, grass and weed spraying and mowing, and fence condition. These costs are forecasted based on the number of facility locations that require regular maintenance as well as condition-based needs.

- The Inspections projected expense primarily consists of Company employee labor hours, services, and necessary material costs. Labor hour projections are based on historical time to perform inspections, required maintenance, and standard work initiatives to meet code, manufacturer recommendations, deliverability, and reliability of gas systems. Inspection units increase as new equipment (gas filtration, liquid separation, gas analyzers, chromatographs, and regulation) is being added to the system. Also, regulation and other ancillary equipment has been added, such as filter-separators and multiple station outputs to meet customer demands. The Inspection activity levels satisfy safety and compliance regulatory requirements of our gas transmission and distribution pipeline systems through inspection and repair of all critical assets to meet regulatory requirements.

- The Non-WBS portion of the sub-program is comprised of labor, materials, and services not associated with a work order. These costs include (a) travel and meal charges, (b) Company laboratory labor for equipment calibration, (c) stock and non-stock material, (d) heater glycols, (e) valve grease, (f) equipment rental charges, (g) storage space rental, (h) purchase power, (i) SCADA cellular bills, (j) repair parts, (k) outside services, (l) contractors, (m) buildings, (n) testing in laboratory services, and (o) parts and materials to support system operations and code work. This portion of the sub-program also includes actions needed to comply with governmental agencies and local ordinances. Costs here are projected based on historical spend.

- Contractor Materials, Credits and Other Expenses portion of the sub-program includes contractor labor, credits, and materials for inspections, preventive maintenance and operations, demand maintenance, and third-party contracts which are directly associated with a specific work order.

The historical year costs and projected test year costs for this program are summarized in the following table:

Table 16

Operation & Maintenance – Transmission Measurement & Regulation Projection Breakdown by Activity Type		
Work Type	**2023 Actual**	**2025-2026 Test year**
Non-WBS	$27,634	$206,363
Contractor; Materials, Credits and Other Expenses	$632,804	$655,373
Demand Maintenance	$597,885	$529,575
Preventative Maintenance	$1,352,067	$1,210,456
Inspections	$649,098	$580,010
Third Party Contracts	$237,088	$201,743
Total Program	$3,496,577	$3,383,519

Q. What is the basis for determining the $3,383,519 of projected O&M expenses in the test year for this program?

A. The test year amount of $3,383,519 is a weighted average of the 2025 (15%) and 2026 (85%) forecast amounts shown above. This reflects the Company's historical experience of program expense timing. Much of the projected expense in this sub-program is derived from the Company's estimated gas transmission field worker jobsite hours.

Each activity includes a forecasted number of units and associated expected average amount of time to complete each unit. The units multiplied by the time to complete, along with anticipated labor rates, account for much of the cost projection. In total, the Company projects jobsite labor hours to be 17,737 hours during the test year in this proceeding.

Gas Transmission worker hourly standard labor rates are expected to be:

Table 17

Transmission				
	Standard Labor Rates	**Indirect Labor Rates**	**Vehicle Rates**	**Total Rate**
2023	$69.18	$24.90	$36.67	$130.75
2024	$72.53	$23.93	$34.81	$131.28
2025	$76.37	$26.73	$32.08	$135.17
2026	$79.28	$27.75	$33.30	$140.33

The historical and projected activity in this program is summarized in the following table:

Table 18

Operations & Maintenance – Measurement & Regulation Transmission Hours & Dollars		
Year (Jan-Dec)	**Hours**	**Dollars**
2016	18,233	$4,609,086
2017	20,497	$3,461,000
2018	20,497	$3,074,000
2019	20,722	$3,005,000
2020	18,540	$2,897,776
2021	17,795	$3,188,919
2022	17,197	$4,339,305
2023	20,394	$3,496,577
2024 Projected	17,936	$3,433,865
2025 Projected	17,737	$3,258,089
2025-2026 Test year	17,737	$3,383,519

Odor Response

Q. Please describe the O&M expenses related to the Odor Response sub-program.

A. This sub-program provides for around-the-clock response to odor calls and other emergencies, including initial response to third-party damages. The Company has been achieving an average annual response time of 30 minutes or less, to ensure the safety of customers and the public.

The Commission monitors the Company performance on response times to ensure the safety of customers and the public. The program consists of Company employee labor costs inclusive of material and fleet costs.

This sub-program deals with initial response to odor calls from customers and the general public. Final resolution of the odor calls, if determined to be caused by leaking gas from Company facilities, may be an O&M repair or a capital asset replacement. The costs of this sub-program cover the O&M portion of the final resolutions. The O&M portion is based on a historical two-year analysis, which is reviewed every year (using a rolling two-year average). This portion/average will fluctuate based on whether the leaks found on gas services and mains are repaired or replaced.

The Odor Response sub-program consists of labor costs that are based on the Reasonable Expectancy to complete each work activity along with known labor rates for the personnel completing the activity. Activities such as the leak investigation standard (six-house check) implemented by the Company in 2018, provides for a more thorough leak investigation. The standard requires Company employees to check the house for which the leak was called in as well as a six-house check, including the buildings next to the reported address and the three buildings on the other side of the main (which are often across the street). They check for leak sources at the service riser/entrance of these buildings.

The historical year costs and projected test year costs for this sub-program are summarized in the following table:

Table 19

Odor Response Projection Breakdown by Activity Type		
Work Type	**2023 Actual**	**2025-2026 Test year**
Odor Response	$6,308,854	$6,440,887
Total Program	**$6,308,854**	**$6,440,887**

Q. What is the basis for determining the $6,440,887 of projected O&M expenses in the test year for this sub-program?

A. The Company has projected the costs of the Odor Response sub-program based on expected workload associated with 42,222 O&M odor response orders.

Each odor response call is expected to require gas service worker jobsite time of 0.75 hours, or about 45 minutes. This expected time requirement is based on reviews during 2023 and 2024 of jobsite time per order completed.

The test year also reflects projected gas service worker hourly standard labor rates, indirect labor rates, and vehicle rates.

Gas Service worker hourly standard labor rates are expected to be:

Table 20

Service				
	Standard Labor Rates	**Indirect Labor Rates**	**Vehicle Rates**	**Total Rate**
2023	$70.23	$105.35	$25.99	$201.56
2024	$73.80	$98.15	$22.14	$194.09
2025	$75.63	$102.86	$22.69	$201.18
2026	$78.52	$106.79	$23.56	$208.86

The historical and projected activity in this sub-program is summarized in the following table:

Table 21

Odor Response Program O&M Units/Orders, Hours & Dollars			
Year (Jan-Dec)	**O&M Units/Orders**	**Jobsite Hours**	**Dollars**
2016	78,719	51,429	$6,339,803
2017	58,892	34,012	$4,521,650
2018	54,743	35,587	$5,265,338
2019	56,755	40,061	$6,146,752
2020	51,500	36,442	$5,506,217
2021	48,248	36,057	$6,159,004
2022	44,729	34,770	$6,445,000
2023	42,023	32,402	$6,308,854
2024 Projected	43,444	32,619	$6,259,031
2025 Projected	37,359	28,020	$5,640,958
2025-2026 Test year	42,000	31,020	$6,440,887

The projection for the test year, is a weighted average of the 2025 (10%) and 2026 (90%) forecast amounts, which reflect the Company's historical experience of program expense timing.

Leak Repair and Survey

Q. Please describe the O&M expenses related to the Leak Repair and Survey sub-program.

A. The Leak Repair and Survey sub-program includes Company labor and contractor services for annual mobile and walking leak surveys, and classification of leaks on mains, services, and meter stands called in by customers or found during leak survey activity.

The sub-program also includes leak repairs to mains, services, and meter stands, including installation of leak repair fittings and clamps, tightening of fittings and clamps, partial service replacement, and rebuilds of meter installations. This work is on the Company's distribution system and helps to ensure public safety. This program includes the costs associated with contracts for maintenance of customer-owned fuel lines and will continue to include those costs as well, in compliance with regulations for master meters operators. In accordance with Mich Admin R 460.20335, the costs associated with central meters, otherwise referred to as master meter systems, run through this Leak Repair and Survey sub-program. These costs are offset by the owner of the master meter system as specified under Mich Admin R 460.20335(d)(4).

The historical year costs and projected test year costs for this sub-program are summarized in the following table:

Table 22

Leak Repair and Survey Projection Breakdown by Activity Type		
Work Type	**2023 Actual**	**2025-2026 Test year**
Leak Survey	$5,339,146	$5,000,000
Leak Classification	$1,573,968	$1,884,986
Leak Assessments	$517,381	$619,616
Leak Repairs – Meter Stands and Regs	$3,286,805	$4,510,960
Leak Repairs – Services	$1,553,816	$2,132,528
Leak Repair – Mains	$2,594,560	$3,531,910
Total Program	**$14,865,676**	**$17,680,000**

Q. What is the basis for determining the $17,680,000 of projected O&M expenses in the test year for this sub-program?

A. The projected expense in this sub-program is primarily driven by:

- Leak survey requirements,
- Leaks found during leak survey,
- Current actionable leaks,
- Leaks requiring repair, and
- Reducing the known leak back log.

Leak surveys are compliance driven per MGSS 192.481, 192.557, 192.613, 192.705, 192.706, 192.721, 192.723, and 192.935, which require line patrol and leak survey frequency for mains, services, and customer-owned gas systems. The frequency of leak surveys is determined by the survey type:

- Scheduled leak surveys - Required on a quarterly, semiannual, annual, three-year, or five-year basis,
- Non-scheduled leak surveys - Required on an as-needed basis,
- Contracted Customer-Owned Gas System Leak Surveys - Varies per contract,

- Discretionary leak surveys - Performed on an as-needed basis.

The Leak Surveys expense for the test year is forecasted to be higher than the previous two years with approximately 400,000 units and 10,000 miles of main. This is based on the code-required schedule and frequency of the gas facilities to be surveyed. The historical and projected **Number of Leaks found during Leak Survey** in this sub-program is summarized in Table 23. The 2024 Projected leaks in the table are based on actuals and a forecasted data.

Table 23

Leaks Found During Survey			
Year (Jan-Dec)	**Above Grade**	**Below Grade**	**Total**
2017	5,220	1,555	6,775
2018	7,931	1,715	9,646
2019	18,393	2,697	21,090
2020	9,842	1,589	11,431
2021	12,009	1,577	13,586
2022	9,714	1,516	11,230
2023	9,151	343	9,494
2024 Projected	19,478	850	20,328

The increase in leaks found, per Table 23, drives the increased required leak repairs. The historical and projected Leak Survey Units, which represents the number of services, in this sub-program is summarized in Table 25. As shown in Table 25, the 2024 projected survey units are 166,433 units higher than 2023 due to the five-year survey schedule. This increased number of surveys is the main contributor to the increase in the number of leaks found for 2024.

Leak Repair Scheduling is required per code by MGSS 192.703, 192.709, 192.711, and Michigan Admin Code R. 460.20318 - 460.20318 - Gas leak investigation;

establishment of service; Michigan Admin Code R. 460.20327 - Section R. 460.20327 - Distribution system; leakage surveys and procedures. Each leak must have a complete leak analysis completed to determine the appropriate leak classification for repair scheduling. As a result of the new leak-found trend, and an initiative to reduce the overall leak backlog, leak repair units are forecasted to be higher than average. Forecasts are based on:

(1) Code requirements regarding leak classifications and repairs on active leaks,

(2) Code requirements on leak survey frequency,

(3) Resource availability, and

(4) Historical averages.

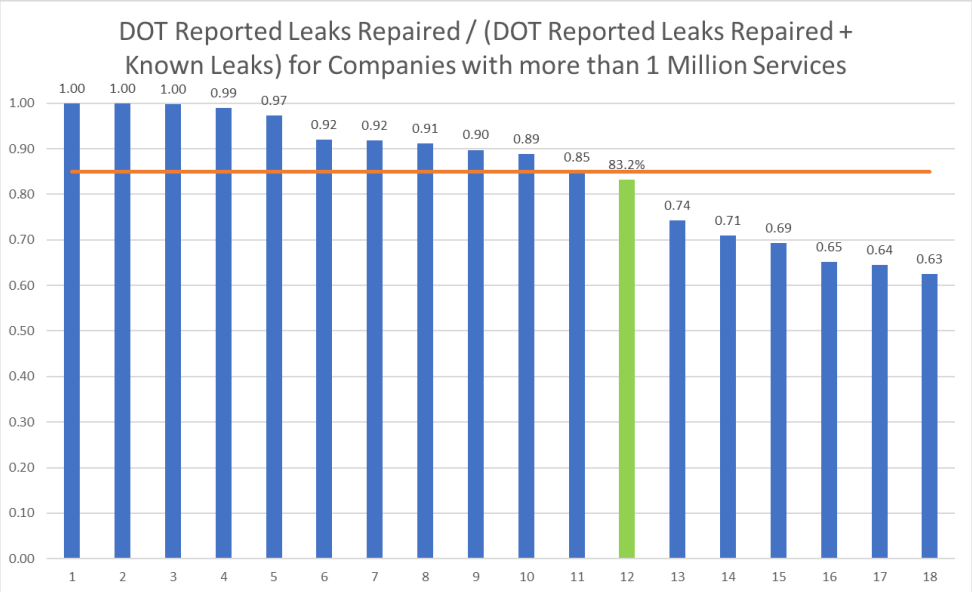
The historical and projected **Leak Repair Units** in this sub-program are summarized in Table 25. The historical and forecasted **Leak Classification** units are shown in Table 25.

The graph below depicts a comparison of natural gas utilities with more than one million customers with vintage main and is based on leaks repaired per leaks repaired and actionable leaks at year end (see the below formula).

$$\% = \frac{Leaks\ repaired}{Leaks\ repaired + Actionable\ Leaks}$$

Consumers Energy is depicted in green, and was at 83% as of year-end 2023, which is just below industry average of 85%. Based on benchmarked data, shown in Figure 1 below, the Company is seeking to position itself in the top of the first quartile, which drives improved system integrity and public safety.

Figure 1



The **leak repairs planned** for 2025 and 2026 will ensure the Company maintains a safe and reliable natural gas system by permanently repairing leaks. and working to eliminate our current leak backlog. Doing so, the Company can enhance public safety, increase the integrity of the natural gas system, reduce methane emissions, and lower long-term costs. With this plan, the Company will eliminate Grade 2 leaks by January 2026 and continue to reduce Grade 3 leaks through the test year. The NGDP will address long-term system integrity.

The projection for Company labor and vehicle costs are primarily based on the projected hours for each year. Increases in labor and vehicle costs from 2023 to the test year also reflect projected gas distribution worker hourly standard labor rates, indirect labor rates, and vehicle rates.

Gas Distribution worker hourly standard labor rates are expected to be:

Table 24

Distribution ($/hr)				
	Standard Labor Rates	**Indirect Labor Rates**	**Vehicle Rates**	**Total Rate**
2023	$69.86	$37.72	$43.31	$150.90
2024	$73.41	$39.64	$33.77	$146.82
2025	$75.58	$40.81	$40.81	$157.21
2026	$78.47	$42.37	$42.37	$163.22

The historical and projected activity in this program is summarized in the following table:

Table 25

Leak Repair and Survey Units/Orders, Hours & Dollars					
Year (Jan-Dec)	**Survey Units**	**Classification Units**	**Repair Units**	**Jobsite Hours**	**Dollars**
2016	462,334	18,734	15,814	96,196	$13,510,903
2017	556,249	13,079	13,815	67,091	$10,908,621
2018	457,641	12,650	18,556	83,858	$16,087,691
2019	480,394	13,374	21,970	98,567	$20,232,711
2020	415,305	12,923	23,649	110,011	$19,802,868
2021	491,858	7,438	18,612	97,692	$21,786,507
2022	352,437	4,695	16,537	83,987	$18,941,796
2023	368,287	3,981	14,132	60,650	$14,865,676
2024 Projected	534,720	5,566	21,402	64,244	$16,714,729
2025 Projected	350,968	5,095	21,331	64,061	$16,760,000
2025-2026 Test year	400,000	5,095	21,594	66,719	$17,680,000

The projection for the test year is a weighted average of the 2025 (5%) and 2026 (95%) forecast amounts, which reflect the Company's historical experience of program expense timing.

Q. Please describe the LDAR Rule impacts to this program.

A. As talked about previously in my testimony, the Company plans to reduce the known leaks on the system, at an accelerated rate, as part of planned work, regardless of the timing of

the rule. The Company has included $1,300,000 is this program, which was allocated among the three Leak Repair work types in Table 2~~2~~1.

Q. Please describe Advanced Methane Detection.

A. In 2024, the Company conducted leak surveys with handheld instrumentation through foot patrol of gas service lines and infrastructure. Advanced Methane Detection uses higher sensitivity instrumentation to detect smaller amounts of gas release than traditional tools. During the test year, the Company plans to use a Grid based approach combined with Advanced Methane Detection to perform leak survey on a portion the Company's natural gas system. Advanced Methane Detection is further explained in Company witness Kristine A. Pascarello's testimony.

Damage Repair

Q. Please describe the O&M expenses related to the Operations & Maintenance - Damage Repair sub-program.

A. The Operations & Maintenance - Damage Repair sub-program involves repairing natural gas mains, services, and meter installations from third-party damages (such as excavators, other utilities, municipalities, and homeowners). These expenses are necessary to ensure public safety, and to bring the system back into service in a timely manner. Consumers Energy's operating employees assess the site, mitigate the gas leak caused by the damage, and make necessary repairs to the system. In addition, the program is the recipient of credits from billing (less write-offs) from these third parties. These credits have shown variability year over year for several reasons, such as volume of damages, third-party response (willingness or ability to pay), and market and economic conditions.

The historical year costs and projected test year costs for this sub-program are summarized in the following table:

Table 26

Operation & Maintenance – Damage Repair Projection Breakdown by Activity Type		
Work Type	**2023 Actual**	**2025-2026 Test year**
Service/Meter Stand Repair	$2,265,200	$2,161,752
Main Repair	$512,158	$488,768
Damage Assessment	$199,067	$189,976
Credits	($1,561,893)	($1,459,000)
Total Program	**$1,414,532**	$1,381,496

Q. What is the basis for determining the $1,381,496 of projected test year O&M expenses for this sub-program?

A. Spending in this sub-program is primarily driven by the number of damages recorded on the system. Projected costs consider historical volume and Company efforts to reduce damages to the gas system. The Company maintains a Public Safety Outreach ("PSO") function, using damage prevention liaisons, that seek to work with third parties through various channels to provide awareness of the gas system, and to prevent damages. Through PSO efforts, damage repairs are projected to be lower in 2025 and 2026. These efforts are meant to reduce costs for the damage repair portion of this program. Offsetting these cost reductions is a reduced level of damage credits being collected from or paid by third parties. A common reason for not billing a third party for damage is that the damaging party is unknown, such as when gas damage occurs, and the party leaves the scene prior to the Company arriving.

Gas distribution worker hourly standard labor rates are expected to be:

Table 27

Distribution ($/hr)				
	Standard Labor Rates	**Indirect Labor Rates**	**Vehicle Rates**	**Total Rate**
2023	$69.86	$37.72	$43.31	$150.90
2024	$73.41	$39.64	$33.77	$146.82
2025	$75.58	$40.81	$40.81	$157.21
2026	$78.47	$42.37	$42.37	$163.22

This historical and projected activity in this sub-program is summarized in the following table:

Table 28

Operations & Maintenance – Damage Repair		
Hours & Dollars		
Year (Jan-Dec)	**Hours**	**Dollars**
2016	17,486	$1,209,306
2017	17,497	$624,348
2018	18,685	$683,225
2019	18,471	$1,102,498
2020	23,753	$2,550,320
2021	19,644	$1,379,759
2022	23,854	$1,574,894
2023	18,402	$1,414,532
2024 Projected	17,615	$1,448,021
2025 Projected	15,898	$1,255,351
2025-2026 Test year	16,298	$1,381,496

The test year projection is a weighted average of the 2025 (18%) and 2026 (82%) forecast amounts, which reflect the Company's historical experience of program expense timing.

Staking & Locating

Q. Please describe the O&M expenses related to the Staking & Locating sub-program.

A. The Staking & Locating sub-program involves Company labor and contractor services for the staking and locating of the Company's gas distribution pipeline facilities in accordance with Act 174 of 2013, MISS DIG 811 Underground Facility Damage Prevention and Safety Act, a key component of securing public and employee safety. Work is typically performed by a contracted outside service vendor on a multi-year contract with the Company.

Q. Please discuss the work activities in the Staking and Locating Sub-Program.

A. The Staking and Locating sub-program includes the following work activity categories:

- Outside Services – Staking and Locating: contractor costs are included for staking and locating activities that are performed under the shared resource model and advanced locating for abnormal operating conditions.

- Outside Services - Dedicated Contractor: contractor costs are included in the test year projection for staking and locating activities that will be performed under the Dedicated Contractor staking program.

- Company Labor: volumes and hours are included in the test year projection for Company labor to support standby inspections, and abnormal operating condition efforts. Included are the projected increases in labor and vehicle costs from 2023 to the test year for gas distribution worker hourly standard labor rates, indirect labor rates, and vehicle rates. The projection for Company labor and vehicle costs are primarily based on the projected hours for each year.

- Licenses, Permits & Fees: This includes the fees that Consumers Energy pays to the state MISS DIG 811 system as part of Act 174.

Q. Please provide a breakdown of the Staking and Locating sub-program expense.

A. The Staking & Locating sub-program expenses for 2023 and the test year expenses are identified in the table below:

Table 29

Staking and Locating Sub-program Projection Breakdown by Activity Type		
Work Type	**2023 Actual**	**2025-2026 Test year**
Outside Services - Staking and Locating (Shared)	$7,865,196	$0
Outside Services - Staking and Locating (Dedicated Oakland and Kent)	$2,766,691	$6,703,509
Outside Services - Staking and Locating (Dedicated remainder of service territory)	$0	$15,112,608
Company Labor	$1,401,778	$1,802,959
Licenses, Permits & Fees	$373,380	$838,409
Total Program	**$12,407,045**	**$24,457,485**

Q. What is the basis for determining the $24,457,485 of projected O&M expenses for this sub-program?

A. Spending in this sub-program is primarily driven by staking request volume (units) and the cost of staking contractors. Table 32 shows the change in staking volumes realized year over year. The primary drivers for this increase include:

(a) Increase of $1,712,991 based on anticipated contractor volume increases of 66,379,

(b) Increase of $401,181 based on Company labor standard labor rate change and increased hours,

(c) Increase in MISS DIG 811 membership fees of $465,029, and

(d) Increase of $9,470,757 based on dedicated model expansion and contractor rate increases.

- The 2024 expansion of Oakland County from 67% to 100% of the dedicated staking ticket volumes, and the 2024 addition of Kent County under the dedicate model accounts for $2,179,247 of the increase.

- The 2025 expansion of the dedicated model to the remainder of the Company's Gas Service Territory, based on performance and the staking Request for Proposal (RFP) results, accounts for $7,291,510 of the increase. The Company is mitigating a higher increase by expanding its Dedicated Contractor approach, which is available at a lower unit cost

than continued use of the Shared Contractor approach and also provides numerous other benefits to customers described in more detail below.

Historical and forecasted expenses for the Staking sub-program are provided in the table below.

Table 30

O & M – Staking & Locating Total Program	
Year (Jan-Dec)	**Dollars**
2016	$5,145,070
2017	$5,828,563
2018	$6,754,042
2019	$8,200,186
2020	$7,306,455
2021	$10,982,945
2022	$10,309,238
2023	$12,407,527
2024 Projected	$15,213,591
2025 Projected	$22,653,823
2025-2026 Test year	$24,457,485

The test year expense projection is based on a weighted average of the 2025 (12%) and 2026 (88%) forecast amounts, which reflect the Company's historical experience of program expense timing.

Q. Please describe the test year cost forecast for volume and unit cost.

A. An anticipated unit cost increase is included in the test year projection for contractor services and with the requirement for enhanced capability to manage increased demand in performance and increasing labor costs.

The staking completed by an outside contracted vendor is billed based on contractual unit costs. An anticipated volume increase of 7.0% is included in the test year projection relative to 2024 contractor services. This is in alignment with the trend of the

historical data and staking forecasts for the state of Michigan. The anticipated contractor unit cost and staking volume increases is shown in the following table.

Table 31

Contractor Stake & Locate Services		
	Base Unit cost ($/unit)	**Base Unit Forecast (units)**
2022	$21.83	407,551
2023	$26.71	412,008
2024 Projected	$30.49	437,004
2025 Projected	$44.66	450,823
2026 Projected	$45.67	482,380

The Statewide MISS DIG 811 Annual Ticket Requests table below shows the change in staking volumes realized year over year.

MISS DIG 811 data (www.missdig811.org/about/who-we-are/about-miss-dig.html) shows a continuous growth in staking and locating ticket requests for the entire State of Michigan, except for a small decline in 2020, which appears to be a temporary result of COVID-19 pandemic business impacts.

The following is the historic and projected Statewide MISS DIG 811 annual ticket requests:

Table 32

Statewide MISS DIG 811 Annual Ticket Requests		
Year	**Annual Ticket Requests**	**% Change From Prior Year**
2016	814,303	
2017	872,896	7.2%
2018	923,993	5.8%
2019	1,015,753	9.9%
2020	994,573	-2.1%
2021	1,088,030	9.4%

2022	1,093,021	1.0%
2023	1,202,992	10.1%
2024 Forecast	1,323,291	10.0%
2025 Forecast	1,415,921	7% Assumed

Q. Please describes the Company's concerns with the increase in staking ticket volumes and proposed recommendation.

A. The Company has estimated staking tickets for the test year based on the best information available at this time. With staking requests increasing due to fiber optic and other infrastructure work, the actual staking demand the Company experiences in 2026 could be above the company's staking volume forecast. While the Company attempts to forecast staking volumes with a high degree of accuracy, the largest factors influencing expenditures in these programs are externally driven. As a result, the Company requests it be allowed to defer for refund or recovery any O&M expenses for this program, below or above amounts included in rates for the test year. The request would avoid a potential budgetary impact on important programs in order to cover the required staking volume costs. It would also prevent customers from paying for costs that were not incurred if staking volumes are below forecasted levels.

Q. Please describe the change in the Company's standard labor rate and volume increase.

A. The projection for Company labor is primarily based on the projected hours for each year. Increases in labor also reflect projected gas distribution worker hourly standard labor rates. The table below shows historic and projected volumes and hours for Company crews.

Table 33

OM&C Labor Breakdown – Advanced Locating & Inspections		
Year (Jan-Dec)	**Units/Orders**	**Hours**
2017	2,771	7,262
2018	2,988	7,281
2019	10,390	13,739
2020	2,366	10,933
2021	11,168	14,877
2022	2,298	8,962
2023	2,692	9,033
2024 Projected	3,436	9,197
2025 Projected	3,453	10,704
2025-2026 Test year	3,606	11,180

Gas distribution worker hourly standard labor rates are expected to be:

Table 34

Distribution ($/hr)				
	Standard Labor Rates	**Indirect Labor Rates**	**Vehicle Rates**	**Total Rate**
2023	$69.86	$37.72	$43.31	$150.90
2024	$73.41	$39.64	$33.77	$146.82
2025	$75.58	$40.81	$40.81	$157.21
2026	$78.47	$42.37	$42.37	$163.22

Q. Why did the Company initially implement the Dedicated Contractor staking strategy?

A. The Company's Dedicated Contractor staking strategy is to hire a contractor that is dedicated to staking only the Company's gas and electric assets. This was originally implemented in a limited portion of the Company's gas service territory because changes in the program were necessary to improve timeliness and accuracy of staking for public safety, especially given the continued ticket volume. Consumers Energy and the State of Michigan are in the fourth quartile for third-party gas distribution damages per

1,000 tickets. When accuracy and timeliness of staking are off target, this creates negative behaviors with third-party excavators, resulting in unsafe digging practices. A critical step in ensuring safe digging practices is having excellence in stake-and-locate timeliness and accuracy.

With a Dedicated Contractor staking strategy, the Company is looking to achieve the following key pillars in support of safe digging and the excavating community.

- The first key objective is *timeliness*. Through the dedicated workforce, the Company will see improved timeliness compared to historical performance to support the excavating community. This will be achieved by having a single utility focus for ticket management. This model improves the ability to manage ticket volume fluctuations throughout the year due to not having the risk of completing all other commitments on the ticket in the shared resource model.

- Another key objective is *quality*, with improved staking accuracy performance compared to recent historical data. This is expected to be achieved as stakers need only focus on one utility type, compared to the shared resource model, where stakers are responsible for all assets (electric, gas, communications, water). This will lead to increased staking proficiency.

- The last key objective is *improved excavator communications* on projects. Improved communications with the excavating community will be enabled by use of enhanced positive response, which provides additional information and pictures to the ticket initiator, and an additional payment type for 180-day project tickets to assist in mitigating the risk of rushing.

Q. Please describe the test year costs for the Dedicated Contractor asset locating program.

A. In the interest of public safety, damage prevention, and in compliance with a facility owner's obligation under Act 174, the act of placing marks to indicate approximate facility location in response to a MISS DIG 811 ticket requested in advance of excavation activity, an anticipated increase in volume and costs are included in the test year projection for gas-only locating. This includes resources to locate *only* gas facilities for Consumers Energy compared to the existing method of vendors locating several other additional

external facilities. Additionally, based on the existing benefits realized and lower comparative costs to the Shared Contractor resources, the Company plans to expand the program in 2025 to include all of the Company's statewide gas service territory.

Q. Please describe the Company's plan to expand the Dedicated Contractor staking program.

A. Based on existing benefit realization for the Dedicated Contractor staking program, the Company plans to expand the program to continue to improve public safety, reduce damages, mitigate communication risks with excavators, improve quality, and comply with timeliness requirement within Public Act 174. Beginning February 21, 2023, the Dedicated Contractor staking program covered two-thirds of Oakland County, which is 20% of the total staking tickets. The plan for 2024 has the Dedicated Contractor staking program covering 31% of the total staking tickets. In 2025, the Company plans to expand the Dedicated Contractor staking Program to include the Company's entire statewide gas service territory and cover up to 100% of the total staking ticket volume.

Q. Please explain why the company accelerated the implementation of the Dedicated Contractor staking model to up to 100% of the total ticket volume in 2025.

A. The staking contract with the contractor that the Company uses for its Shared Contractor approach expires in the first quarter 2025. In anticipation, the Company sent out a request for proposal in the third quarter of 2024 for staking services for the Company's remaining gas service territory that at the time was under the Shared Contractor resource model. The request included options for both shared and dedicated services. The bids yielded an average unit cost for the Dedicated Contractor resource model that was below the average unit cost of the Shared Contractor staking model. Based on the lower unit cost, the realized

timeliness, and quality improvement from the Dedicated Contractor resource model, the Company plans to pursue the lower cost Dedicated Contractor option and implement a statewide Dedicate Contractor staking approach for its gas service territory for up to 100% of the total staking ticket volume.

Q. Please describe the benefits the Company has seen since implementing the Dedicated Contractor staking program.

A. The Company has seen benefits to overall accuracy, timeliness, and excavator communications on projects since the implementation in February 2023.

In 2023, with the Dedicated Contractor resource model in place, two-thirds of Oakland County (compared to the Shared Contractor resources model in 2022) yielded the following results:

- Accuracy related to at-fault damage reduction improved by 87.3%.
- Field timeliness for the Dedicated Contractor model averaged 98.7% compared to 97.3% for the Shared Contractor resource model in 2023.

For 2024, year-to-date month ending September, the Dedicated Contractor model in place for Oakland and Kent County's compared to the Shared Contractor resources model yielded the following results:

- Accuracy related to at-fault damage reduction improved by 78.6% from 2022.
- Field timeliness for the Dedicated Contractor model averaged 99.5% (including 24 hour re-transmits) compared to 95.2% for the Shared Contractor resource model in 2024.

These results are anticipated to continue due to improvement in staking and locating performance. Additionally, excavator communication on projects has improved through enhanced positive response, which provides an overview of staking and associated pictures to the ticket requester.

Q. Please describe the cost difference between the Shared Contractor resource model and Dedicated Contractor resource model after the RFP.

A. The RFP bids were evaluated using actual 2024 ticket type data with redline and performance incentive adjustments made to provide an accurate comparison between the Shared Contractor resource model and Dedicated Contractor resource model bids. The analysis shows the Dedicated Contractor model is on average $10.90 less on a per unit basis when compared to the Shared Contractor model. Continuing with the Shared Contractor model, and not transitioning to the Dedicated Contractor resource model, would increase program cost by $3,667,000 for the Company's remaining gas service territory in the test year.

Q. Has the Company added communication audits to assist in validating appropriate positive response code utilization as a result of the MPSC Safety Staff's recommendations in the Company's previous gas rate case?

A. Yes. The Company is enhancing communication audits executed by the Company's Damage Prevention Field Liaisons as well as updating timeliness reporting to include county level data in addition to statewide, to assist in identifying incorrect positive response code utilization.

Q. What other activities does the Company perform to reduce dig-in damages besides stake and locate?

A. In addition to the stake and locate program, the Company has a robust damage prevention program that includes damage prevention and public safety liaisons, and public awareness activities.

Damage prevention and public safety liaisons focus on proactive support for the excavating community, including but not limited to training, troubleshooting locating needs, and communications and issues management for all involved stakeholders. The liaisons also play a critical role in the Company's damage investigation program, repeat damager program, and no-call program, where the liaisons follow up on damages in which MISS DIG 811 was not called. Additionally, they perform quality assurance audits on the Company's staking contractors for accuracy in locates. The Company has eight public safety liaisons, with the most recent being a dedicated individual for the gas transmission system due to an increasing number of near misses on the transmission pipelines. The Company has implemented the Irth Solutions UtiliSphere solution as a critical part of the damage prevention 811 ticket management. It enables standardization for field processes and supporting data. It can prioritize tickets and field activities, which help to mitigate the highest risks.

Customer Requested Services

Q. Please describe the O&M expenses related to the Operations & Maintenance – Customer Requested Services sub-program.

A. This sub-program includes the following work activity categories:

- Customer and Company Requested Service activities include Company labor and contractor services for meter and meter stand work, and appliance re-lights after interruptions. Interruptions may be customer driven or related to Company work such as gas facility replacement projects. This category also includes gas meter investigations associated with operational and billing issues.

- Charts and Inspection activities include gas meter inspections and battery exchanges. This work is associated with the metering equipment for commercial and industrial customers. The charts and inspection requirement helps to ensure accuracy in gas flow and utilization.

- Gas Meter Routine activity includes scheduled and companion gas meter exchanges. This work fulfills the Company's Routine Meter Exchange Program. Every year, the Company removes (exchanges) a sample of meters (specific years and types) and tests them for billing accuracy to fulfill MPSC requirements. The number of exchanges required annually is determined according to the testing procedures currently in effect, which specifies how meters are grouped and how many meters of each lot are to be removed and tested annually.

- Meter Work activities including gas turn-ons, turn-offs, investigative tests, as well as setting and removing meters. This work is both emergent and customer committed and is planned based on historical levels; transportation customer meter reads are part of this activity. Also, Smart Energy Advanced Metering Infrastructure ("AMI")/Automated Meter Reading ("AMR") activities were added to the program in 2017 with the implementation of the Gas AMI/AMR project. All activities associated with the gas communication modules are included in this activity, which are investigations, removals, exchanges, and installations of gas communication modules. Deployment has completed, and work has shifted to troubleshooting communication issues with the AMI/AMR meters.

- Non-WBS portion of the sub-program includes labor, internal departmental chargebacks, contractors, and materials not directly associated with a specific work order.

- Contractor Materials, Credits and Other Expenses portion of the sub-program includes Contractor labor, credits, and materials for work associated with the activities below.

The historical year costs and projected test year costs for this sub-program are summarized in the following table:

Table 35

Operations & Maintenance – Customer Requested Services Projection Breakdown by Activity Type		
Work Type	**2023 Actual**	**2025-2026 Test year**
Non-WBS	$908,747	$1,083,169
Contractor; Materials, Credits and Other Expenses	$339,204	$553,924
Cust Req Services	$4,262,969	$4,501,755
Charts & Inspections	$2,061,833	$2,250,878
Routines	$2,860,814	$3,001,170
Meter Work	$8,443,283	$9,003,511
Total Program	**$18,876,849**	**$20,394,406**

Q. What is the basis for determining the $20,394,406 of O&M expenses in the test year as requested for this sub-program?

A. The costs of the sub-program are primarily driven by Company gas service worker labor, materials, and vehicle expenses. Labor costs consider the amount of jobsite time needed to complete each work activity along with standard labor rates and indirect labor rates for the personnel completing the activity. The Company moved the work type no-gas investigation and repair from this program in 2024 to the Operations and Maintenance – Distribution sub-program. For this sub-program, the units and hours from 2023 to the test year are higher due to the increase in inactive meter removal, routine exchanges associated with rebuilds to top connect stands, and seal for non-pay turn on. Gas Service worker hourly standard labor rates are expected to be:

Table 36

Service ($/hr)				
	Standard Labor Rates	**Indirect Labor Rates**	**Vehicle Rates**	**Total Rate**
2023	$70.23	$105.35	$25.99	$201.56
2024	$73.80	$98.15	$22.14	$194.09
2025	$75.63	$102.86	$22.69	$201.18
2026	$78.52	$106.79	$23.56	$208.86

This historical and projected activity in this program is summarized in the following table:

Table 37

Operations & Maintenance – Customer Requested Services Units/Orders, Hours & Dollars			
Year (Jan-Dec)	**Units/Orders**	**Hours**	**Dollars**
2016	216,935	105,474	$14,468,136
2017	229,333	110,080	$15,410,859
2018	211,300	106,027	$15,885,423
2019	186,242	102,968	$16,711,353
2020	134,870	73,132	$12,113,609
2021	150,212	82,741	$15,519,751
2022	160,647	92,868	$19,198,250
2023	153,649	87,195	$18,876,849
2024 Projected	169,468	87,508	$18,258,562
2025 Projected	173,310	89,816	$19,679,376
2025-2026 Test year	174,514	90,356	$20,394,406

The test year expense projection is based on a weighted average of the 2025 (16%) and 2026 (84%) forecast amounts, which reflect the Company's historical experience of program expense timing.

Meter First Set Credits

Q. Please describe the Operations & Maintenance – Meter First Set Credits sub-program.

A. The Operations & Maintenance – Meter First Set Credits sub-program offsets the initial labor costs to install a newly purchased natural gas meter (or First Set Cost), and the final

labor costs to remove the meter from service prior to retiring and scrapping the meter (or Cost of Removal). Meters are capitalized on purchase, per FERC accounting rules, and these credits offset the installation costs of the meters upon purchase and final disposal of meters.

The Company establishes an annual meter purchase plan for each year in June of the preceding year. That purchase plan provides for meter quantities and types, broken into periodic releases from meter manufacturers throughout the year, to meet all business requirements. Those requirements include new business sets, service upgrades, for-cause exchanges (such as damage, leak, and obsolescence), project work such as Enhanced Infrastructure Replacement Program ("EIRP"), and regulatory testing requirements. Factors considered when establishing the annual plan include current levels of inventory by meter type, assumptions of new business services expected in the coming year, historical for-cause exchange data, project work projections, historical trending for meter retirements, and regulatory program (i.e., the Routine Meter Exchange Program) projections. The plan calls for receiving shipments of meters at different points throughout the year, so the Company can adjust the orders as actual inventories are observed.

Q. What is the basis for determining the $7,959,910 projected O&M credit in the test year?

A. This O&M offset is primarily driven by the purchase of new gas meters. During the test year period, the Company plans to purchase 47,043 new gas meters. The expected credit from these purchases during the test year is $4,419,910. The credit is calculated monthly based on the standard labor rate of employees performing the work, the vehicle loading rate, and the indirect labor costs such as travel time that an employee spends performing

their work. This rate is applied to each meter purchased during that month based on the average time required to install the meter to determine the O&M first set credit.

During the test year period, the Company plans to retire 42,000 existing gas meters. The expected credit from these meter retirements is $3,540,000.

The cost of removal credit rate is calculated monthly based on the standard labor rate of employees performing the work, the vehicle loading rate, and the indirect labor costs incurred as employees perform the work. This rate is applied to each meter retired from service during that month based on the average time required to remove the meter from service to determine the O&M cost of removal credit. The annual dollar amount of first set credits is tied directly to the number of units of natural gas meters purchased.

The annual dollar amount of the cost of removal credits is directly tied to the number of units of natural gas meters retired from service during the year. Actual and projected amounts for 2016 through the test year are shown in the table below:

Table 38

Operations & Maintenance – Meter Credits Units/Orders, Hours & Dollars			
Year (Jan-Dec)	**Units Purchased**	**Units Retired**	**Dollars**
2016	73,707	53,518	($4,918,315)
2017	77,380	55,846	($6,782,867)
2018	65,471	50,654	($6,636,758)
2019	61,570	43,207	($7,064,014)
2020	58,997	42,471	($6,810,432)
2021	49,759	38,230	($7,062,668)
2022	20,902	39,631	($5,451,241)
2023	35,200	65,222	($6,942,199)
2024 Projected	43,107	48,480	($8,104,000)
2025 Projected	47,546	42,000	($8,490,090)
2025-2026 Test year	47,043	42,000	($7,959,910)

The test year expense projection is a weighted average of the 2025 (17%) and 2026 (83%) forecast amounts, which reflect the Company's historical experience of program expense timing.

ROW Clearing

Q. Please describe the O&M expenses related to the ROW Clearing sub-program.

A. The ROW Clearing sub-program expenses are needed for clearing and vegetation management for the Company's nearly 2,800 miles of natural gas transmission and storage field pipelines. The Company has historically performed minimum clearing necessary to complete inspections, repairs, replacement of pipe, and limited demand clearing for emergent work.

ROW clearing for gas transmission lines at a cyclical program level began in 2020. The projected test year amount of $2,047,934 will permit the continued clearing and herbicide treatment of approximately 400 miles of transmission line ROW per year.

This will place the natural gas transmission and storage pipeline system on an approximate seven-year clearing cycle to optimize the resources needed to maintain the ROW and prevent the growth of large trees that require hand cutting. A seven-year clearing cycle will allow the Company to create a sustainable integrated vegetation management program to minimize woody vegetation growth. This will also allow the gas transmission ROWs to be maintained at full width, increasing awareness for nearby property owners, and making encroachments on the ROW more visible. This seven-year cycle represents the maximum period between clearings to permit aerial patrol and ground line patrol, leak survey, and identify encroachments. The integrated vegetation management program promotes pollinator species and bird species dependent on early successional habitat, whose populations have been on the decline in the United States due to habitat loss. This additional environmental benefit does not affect the cost of the clearing program.

Table 39

Right-of-Way Clearing		
Projection Breakdown by Activity Type		
Work Type	**2023 Actual**	**2025-2026 Test year**
Salary & Expenses	$219,714	$254,637
Mechanical Clearing Treatments	$1,274,254	$1,476,792
Herbicide Treatments	$273,097	$316,505
Total Program	**$1,767,066**	**$2,047,934**

Q. What is the basis for determining the $2,047,934 of projected O&M expenses in the test year for this sub-program?

A. The projected expenses in this sub-program are primarily driven by the planned miles to be cleared and maintained. In Case No. U-20322, the Company proposed increased funding to implement a vegetation management program with a seven-year clearing cycle.

For the fourth full year of the plan implementation in 2023, the Company spent $1,767,066 and is targeting and on track to spend $1,623,888 in 2024.

The 2024 program includes the continued implementation of the herbicide treatment portion of the integrated vegetation management program, which is offset one year following mechanical clearing treatments. The Company is on track to continue to clear 400 miles annually, including herbicide as part of the integrated vegetation management program for ROW Clearing at the projected test year spending of $2,047,934. The projected cost increase reflects the program theoretically getting on cycle. So rather than continuing to reclaim the ROW as in previous years, the Company's intent is to reach a managing phase of the program. The 2020 actual miles and expense through the test year plan miles and expense are shown in the table below.

Table 40

Right of Way Clearing		
Miles & Dollars		
	Miles	
Year (Jan-Dec)	Cleared	Dollars
2016	n/a	$86,364
2017	n/a	$535,582
2018	n/a	$1,095,233
2019	n/a	$358,880
2020	412.6	$1,147,835
2021	423.0	$1,844,924
2022	304	$1,827,267
2023	424	$1,767,066
2024 Projected	400	$1,623,888
2025 Projected	400	$1,613,888
2025-2026 Test year	400	$2,047,934

The test year expense projection is a weighted average of the 2025 (9%) and 2026 (91%) forecast amounts, which reflect the Company's historical experience of program expense timing.

Meter Reading

Q. Please describe the O&M expenses related to the Meter Reading sub-program.

A. The Meter Reading sub-program includes Company employee labor, business expenses (such as fleet costs, and training), and technology expenses (hardware and software maintenance, cellular, and system improvements) for purposes of obtaining meter indexes for the calculation of customer bills.

The Company obtains meter indexes by three methods:

1. The mobile collection of meter indexes using AMR equipped vehicles on scheduled routes.
2. The automated collection of meter indexes using the Company's AMI meters.
3. The manual collection of meter indexes by walking up to meter installations to obtain reads.

The Company achieved overall year-end gas meter read rates of 99.76% in 2022 and 99.73% in 2023. The year-end meter reading results for 2022 and 2023 for the various processes used by the Company are as follows:

Table 41

	Meters Available		Meters Read		Meter Read Rate	
Year	**2022**	**2023**	**2022**	**2023**	**2022**	**2023**
Gas AMR	13,699,110	13,787,192	13,685,051	13,767,861	99.90%	99.86%
Gas AMI	8,006,601	8,047,105	7,986,287	8,023,901	99.75%	99.71%
Manual Gas Reads	168,382	159,831	150,886	143,063	89.61%	89.51%

The Meter Reading sub-program is managed jointly for the Company's electric and natural gas operations. As a result, the total meter reading costs are allocated between

electric and natural gas. The average gas/electric allocation for the test year is projected to be 39% electric and 61% gas; in 2023, the allocation was split 38.8% electric and 61.2% gas. The difference between the 2023 actual and projected test year electric and gas allocation considers the optimization of AMR and manual routes.

A comparison of the 2023 actual and test year projection is provided below:

Table 42

Meter Reading		
Projection Breakdown by Activity Type		
Work Type	**2023 Actual**	**2025-2026 Test year**
Meter Reader Salaries	$294,822	$317,050
Supervision & Administration Salaries	$1,555,897	$1,673,203
Meter Reading Expenses	$756,696	$813,747
Total Program	$2,607,415	$2,804,000

Q. What is the basis for determining the $2,804,000 of projected O&M expenses in the test year for this sub-program?

A. Spending in this sub-program is primarily driven by Company employee labor, business, and technology expenses. The test year projected expense is $2,804,000, which is an increase of $196,585 because of increased technology fees and annual labor salary increases.

For the test year, the number of gas meter reader operating employees is projected to be 22 employees. These employees will navigate AMR mobile collection vehicles and continue to manually read approximately 14,790 gas meters.

The manual reads occur for the following reasons: opt-out customers (Opt Out Not Cut Over), out of scope meters (i.e., commercial/industrial meters) (Not Cut Over), and rate not eligible accounts (Rates ineligible).

The table below shows this breakdown as well, separated between Legacy and Smart meter customers:

Table 43

August 2024	
Gas Customers Not Cut Over To AMI/AMR	
Description	**Manually Read Meters Count**
Legacy Not Cut Over	4,162
Legacy Opt Out Not Cut Over	5,293
Legacy Rates Ineligible for GCM	2,649
Total Legacy Not Cut Over	**12,104**
GCM AMR Not Cut Over	941
GCM AMR Opt Out Not Cut Over	0
GCM AMR Rates Ineligible	903
GCM AMI Not Cut Over	608
GCM AMI Opt Out Not Cut Over	0
GCM AMI Rates Ineligible	160
Total Smart Not Cut Over	**2,612**
GRAND TOTAL NOT CUTOVER	**14,716**

The following table provides the actual meter reading O&M cost for 2016 through 2023, as well as forecasted amounts for 2024 through the test year:

Table 44

Meter Reading		
Equivalent Staffing & Dollars		
	Average	
Year (Jan-Dec)	Gas Staff	Dollars
2016		$13,582,033
2017		$12,328,228
2018	112	$10,499,528
2019	67	$7,633,272
2020	31	$4,097,383
2021	23	$2,830,688
2022	22	$2,592,247
2023	22	$2,607,415
2024 Projected	22	$2,567,867
2025 Projected	22	$2,624,385
2025-2026 Test year	22	$2,804,000

The expense projection for the test year is a weighted average of the 2025 (17%) and 2026 (83%) forecast amounts, which reflect the Company's historical experience of program expense timing.

Meter Technology and Management System Support

Q. Please describe the O&M expenses related to the Meter Technology and Management System Support sub-program.

A. The Meter Technology and Management System Support sub-program ensures the safety, accuracy, maintenance, and stability of the Company's natural gas metering equipment. This program supports the verification of meter accuracies for all customer classes. The program costs are associated with testing and refurbishing gas meters, instrument correctors, gas communication modules, and regulators in response to the Company's Routine Meter Exchange Program.

In July of 2020, the Company combined the Meter Technology Center ("MTC") and the Smart Energy Operations Center ("SEOC") into one combined operation. The

SEOC Program includes the gas portion of the labor and expenses relating to the SEOC daily responsibilities in connection with obtaining AMR meter reads. This includes troubleshooting the equipment, order creation, and IT system demand requirements.

The SEOC is responsible for the reliability and data delivery of the AMI electric meters and AMR gas communication modules. Electric-related costs are not included in this filing. The SEOC benefits customers by providing actual meter reads, minimizing the number of estimated bills, and providing reliable and timely data through daily AMI and monthly AMR meter interrogations.

The 2023 historical expense and the test year projected expense are summarized in the following table:

Table 45

Meter Tech & Mgmt Sys Support		
Projection Breakdown by Activity Type		
Work Type	**2023 Actual**	**2025-2026 Test year**
Exempt/Non-Exempt Salaries	$206,101	$224,490
OM&C Salaries	$740,763	$806,857
Expenses	$338,454	$368,652
Meter Correctors (began to purchase as O&M in 2022)	$246,460	$2,598,000
Total Program	$1,531,778	$3,998,898

Q. What is the basis for determining the $3,998,898 projected O&M expenses in the test year for this sub-program?

A. This sub-program expense is primarily driven by labor, operating, and material costs.

In 2021, a determination was made relative to stand-alone natural gas meter correctors, which had previously been purchased under the Gas Meters capital program, that the components were considered replacement parts and would be purchased under the O&M program going forward, starting in 2022. The change in purchasing instrument

correctors in this program represents a $2,598,000 impact in the test year, purchasing 4,354 ~~2,190~~ stand-alone units. The test year projected program requirement represents normal business expenses with the change in categorization of the gas meter corrector purchases. The following table provides the actual O&M cost for 2016 through 2023, as well as forecasted amounts for 2024 through the projected test year:

Table 46

Meter Tech & Mgmt Sys Support Dollars			
	Labor	Other	Total
Year (Jan-Dec)	Dollars	Dollars	Dollars
2016	$1,198,957	$67,162	$1,266,120
2017	$1,218,563	$64,613	$1,283,175
2018	$1,265,965	$82,867	$1,348,832
2019	$1,227,567	$85,006	$1,312,573
2020	$1,040,289	$45,134	$1,085,423
2021	$1,055,672	$213,094	$1,268,766
2022	$1,106,459	$320,326	$1,426,785
2023	$950,010	$581,768	$1,531,778
2024 Projected	$1,048,202	$1,059,850	$2,109,560
2025 Projected	$1,119,870	$2,711,130	$3,831,000
2025-2026 Test year	$1,031,348	$2,967,550	$3,998,898

The test year expense projection is a weighted average of the 2025 (19%) and 2026 (81%) forecast amounts and reflect the Company's historical experience of program expense timing.

Smart Energy Metering Technology Center

Q. Please describe the O&M expenses related to the Smart Energy Metering Technology Center sub-program.

A. The Smart Energy Metering Technology Center sub-program includes:

(i) The gas portion of expenses related to software maintenance for gas communications modules installed on locations in which the module communicates data through the electric meter.

(ii) The gas portion of the cellular communication expenses allocated to gas communication modules that pass data through the electric meter.

(iii) The gas portion of a technical support contract with the Company's AMI/AMR vendor.

These costs are contractually based through 2032 on a per meter or communication module basis.

Table 47

Smart Energy MTC – Gas		
Projection Breakdown by Activity Type		
Work Type	**2023 Actual**	**2025-2026 Test year**
Communication Charges	$250,982	$255,609
GCM Software Maintenance	$167,860	$170,954
Technical Support Services Contract	$125,000	$127,304
Total Program	$543,842	$553,867

Q. What is the basis for determining the projected O&M expenses in the test year for this sub-program?

A. The projected expense is based on the number of units of AMI-programmed gas modules installed in the field and in inventory to support operations.

With the completion of deployment, the AMI gas module population, subject to a portion of the cellular and software maintenance expenses, has stabilized at a level to include all installed meters and inventory required to support new installations going forward. This should also provide for replacement of existing meters for cause (an error/malfunction) or routine exchange requirements. In addition, per the contract that runs through 2032, the software maintenance expense per unit increases 3% per year. Actual and projected amounts for 2016 through the test year, are shown in the table below:

Table 48

Smart Energy MTC – Gas Dollars	
	Total
Year (Jan-Dec)	Dollars
2016	0
2017	$846,677
2018	$598,586
2019	$606,147
2020	$542,619
2021	$565,536
2022	$542,948
2023	$543,842
2024 Projected	$554,888
2025 Projected	$553,867
2025-2026 Test year	$553,867

The test year expense projection is a weighted average of the 2025 (13%) and 2026 (87%) forecast amounts, which reflect the Company's historical experience of program expense timing.

Gas Storage

Q. Please describe the O&M expenses related to the Gas Storage sub-program.

A. Gas Storage sub-program O&M expenses are directly associated with various maintenance and operational tasks purposed to ensure the predictable and safe operation of the natural gas storage system. The natural gas storage system includes 15 gas storage fields, 808 gas storage wells, and 244 miles of gathering lines, with associated valving, conditioning systems, and access roads. The program funds critical tasks associated with operability and regulatory compliance. Tasks that are executed annually through this sub-program include valve and operator inspections, line patrol and leak survey, integrity monitoring, inspection and maintenance of regulators and relief valves, surface and subsurface safety valves,

isolation valves, fluid separators, and fluid disposal systems. In addition, the Gas Storage O&M sub-program ensures near real-time emergency response preparedness.

This sub-program includes the following work activity categories:

- Non-WBS portion of the sub-program includes labor, internal departmental chargebacks, contractors, and materials not directly associated with a specific work order.

- Contractor Materials, Credits and Other Expenses portion of the sub-program includes contractor labor, credits, and materials for Code Inspection, Facilities Locating for Third Parties (MISS DIG 811), Demand/Preventive/Compliance Maintenance and Operations which are directly associated with a specific work order.

- Code inspections and compliance work is in adherence to all applicable local, state, and federal laws, including those implemented by the MPSC, EGLE, PHMSA, Environmental Protection Agency, Bureau of Land Management, and Michigan Occupational Safety and Health Administration. Regulatory Maintenance activities include pigging activities, corrosion prevention, dehydrator and separator preventative maintenance, valve and operator inspection and repair, access road maintenance, regulator and relief inspections, pipeline patrol, and leak survey to ensure public safety.

- Operation and integrity work includes the bi-annual pressure survey of all 15 fields for reservoir integrity and inventory verification, monthly wellhead pressure monitoring to ensure asset integrity and deliverability, configuring of gas storage fields for injection/withdraw cycles, and routine inspection of assets during winter operations/peak demand.

- Demand maintenance has trended consistent historically. Drivers of these costs include gas storage well intervention, integrity demonstration, and issues affecting gas flow deliverability. This may include well intervention, well logging, freezes in pipelines, snow plowing to ensure access facilities, and response to periodic equipment and system failures requiring intervention and corrective measures to maintain reliability and public safety.

The historical year costs and projected test year costs for this program are summarized in the following table:

Table 49

Gas Storage O&M Projection Breakdown by Activity Type		
Work Type	**2023 Actual**	**2025-2026 Test year**
Non-WBS	$1,699,628	$1,456,458
Contractor; Materials, Credits and Other Expenses	$909,821	$910,911
Code Inspections	$1,559,900	$1,548,457
Facilities Locating for Third Parties (MISS DIG 811)	$828,615	$822,537
Demand/Preventive/Compliance Maintenance	$890,681	$884,147
Operations	$53,032	$52,643
Less: Facility Chargebacks	($202,567)	($202,567)
Total Program	$5,739,110	$5,472,586

Q. What is the basis for determining the $5,472,586 of projected O&M expenses in the test year for this sub-program?

A. The projected expense for this sub-program is historically based, and primarily driven by known units (labor hours) and historical actuals execution of tasks associated with the following activities: compliance inspections, maintenance inspections, operation of the gas storage facilities to meet gas flow deliverability needs and third-party damage prevention tasks (such as locate/stake, crossings, and contractor oversight) to ensure public safety, code compliance, maintenance of critical assets, and operation of the system to deliver natural gas across the state.

These tasks include monthly well site visits and operational support of the Annular monitoring program, including well intervention. Gas transmission worker hourly standard labor rates are expected to be:

Table 50

Transmission ($/hr)				
	Standard Labor Rates	**Indirect Labor Rates**	**Vehicle Rates**	**Total Rate**
2023	$69.18	$24.90	$36.67	$130.75
2024	$72.53	$23.93	$34.81	$131.28
2025	$76.37	$26.73	$32.08	$135.17
2026	$79.28	$27.75	$33.30	$140.33

The historical and projected activity in this sub-program are summarized in the following table:

Table 51

Gas Storage O&M Dollars	
Year (Jan-Dec)	**Dollars**
2016	$7,062,022
2017	$5,667,339
2018	$6,305,807
2019	$6,187,826
2020	$5,821,338
2021	$5,860,452
2022	$6,338,065
2023	$5,739,110
2024 Projected	$5,355,743
2025 Projected	$4,771,940
2025-2026 Test year	$5,472,586

The test year expense projection is a weighted average of the 2025 (12%) and 2026 (88%) forecast amounts, which reflect the Company's historical experience of program expense timing. The test year expense is lower due to the following factors: maintenance is decreasing due to abandonment of some facilities (wells), and increased compliance inspections leading to less equipment-related failure.

Replace Vintage Services

Q. Please describe the O&M expenses related to the Replace Vintage Services ("RVS") sub-program.

A. The O&M expenses for RVS sub-program occur because a small percentage of planned capital RVS orders are not able to be completed as planned.

Reasons for these orders not being completed include field crew identification of services that are already plastic, construction barriers such as service connections to mains that exist under construction barriers such as poles or trees, field crew identification of forced sewer facilities, meters that are not reasonably accessible, excessive main depth, high ground water conditions, evidence of other underground facilities that were unable to be located, and orders for branch services that do not qualify as capital assets.

The historical year costs and projected test year costs for this program are summarized in the following table:

Table 52

Replace Vintage Services		
Projection Breakdown by Activity Type		
Work Type	**2023 Actual**	**2025-2026 Test year**
Replace Vintage Services	$13,897	$70,926
Total Program	**$13,897**	**$70,926**

Q. What is the basis for determining the $70,926 of projected O&M expenses in the test year for this sub-program?

A. The forecast for 2025 and 2026 anticipates that a small percentage of RVS construction orders will be returned from the field as non-constructible. The Company plans to replace

4,164 services in 2025 and 5,913 services in 2026. The expected non-constructible rate is expected to be 1.30% of planned units.

The historical and projected activity in this sub-program is summarized in the following table:

Table 53

Operations & Maintenance – Replace Vintage Services Units/Orders, Return Rate & Dollars			
Year (Jan-Dec)	**VSR Planned Units**	**Return Rate**	**Dollars**
2016	NA	NA	NA
2017	6,307		$1,324
2018	9,381		$102,593
2019	5,571		$90,072
2020	5,456		$83,994
2021	5,056	1.25%	$298,453
2022	2,176	1.25%	$98,417
2023	1,228	1.4%	$13,897
2024 Projected	2,424	1.30%	$70,289
2025 Projected	4,164	1.30%	$70,289
2025-2026 Test year	5,913	1.30%	$70,926

The test year expense projection is a weighted average of the 2025 (36%) and 2026 (64%) forecast amounts, which reflect the Company's historical experience of program expense timing.

Gas Operations Field Operations

Q. Please describe the O&M expenses related to the Gas Field Operations sub-programs shown on Exhibit A-88 (JPP-3).

A. The Gas Field Operations sub-programs includes training for approximately 1,500 natural gas field operations employees.

Also included is training for the Company's gas construction workforce, small tools, natural fiber clothing, safety equipment, field operation expenses, labor and expenses for personnel who are responsible for statewide scheduling and assignment of requested work, and management and administrative personnel of Gas Operations to ensure the safe and effective operation of the gas facilities.

Training

Q. Please describe the O&M expenses related to the Training sub-program.

A. The Training sub-program includes training for approximately 1,500 natural gas field operations employees, including Operator Qualification ("OQ") training, in accordance with applicable regulations. Examples of training provided under this sub-program include equipment operator, pipe joining, valve inspection and maintenance, welding, and pressure control (regulation).

Safety training is also included in this program, which drives improved safety performance in gas field operations. Gas field operations employees receive training each year to ensure a highly skilled workforce qualified to safely operate, maintain, and execute the tasks necessary to meet customer and work demands.

The historical year costs and projected test year costs for this program are summarized in the following table:

Table 54

Operation & Maintenance – Training Projection Breakdown by Activity Type		
Work Type	**2023 Actual**	**2025-2026 Test year**
Gas Operations OM&C Training	$4,330,190	$4,507,764
Athletic Trainers	$313,140	$245,045
Gas Training Non-Labor Expense	$92,353	$91,440
Total Program	**$4,735,683**	**$4,844,249**

Q. What is the basis for determining the $4,844,249 of projected O&M expenses in the test year for this sub-program?

A. Spending in this sub-program is primarily driven by the hours of training conducted for Gas Operations employees. This training is required to ensure a skilled and qualified field operations workforce is available that can complete all customer-requested and compliance-based tasks.

The historical and projected activity in this program is summarized in the following table:

Table 55

Training Hours & Dollars		
Year (Jan-Dec)	**Training Hours**	**Dollars**
2016	77,351	$5,141,541
2017	74,539	$5,718,735
2018	100,790	$6,786,833
2019	83,324	$6,145,865
2020	50,033	$4,698,219
2021	85,722	$6,246,682
2022	83,518	$6,205,592
2023	73,753	$4,735,683
2024 Projected	60,679	$4,150,817
2025 Projected	68,430	$4,607,108
2025-2026 Test year	69,749	$4,844,249

The test year expense projection is a weighted average of the 2025 (14%) and 2026 (86%) forecast amounts, which reflect the Company's historical experience of program expense timing.

Tools

Q. Please describe the O&M expenses related to the Tools sub-program.

A. The Tools sub-program includes the acquisition of small tools, natural fiber clothing, and safety items for field employees.

This ensures employees complete field work in a safe, efficient, and effective manner. Natural Fiber clothing is a required personal protective equipment provided by the Company for employees in the field and who may be exposed to an area where natural gas is present.

Tools included in this sub-program are small hand tools, and any tool used in the field that had an original cost of less than $1,000. Fusion equipment, drills, grinders, and clamps are examples of tools that would be purchased under this program.

Q. What is the basis for determining the $1,431,000 of projected O&M expenses in the test year for this sub-program?

A. The projected expense for this sub-program is based on historical levels as well as any known work plan needs and headcount changes for the test year period. The historical and projected activity in this program is summarized in the following table.

Table 56

Tools	
Dollars	
Year (Jan-Dec)	**Dollars**
2016	$1,805,705
2017	$1,938,712
2018	$2,136,931
2019	$1,702,554
2020	$1,785,981
2021	$1,691,000
2022	$3,065,612
2023	$1,827,711
2024 Projected	$1,438,372
2025 Projected	$788,998
2025-2026 Test year	$1,431,000

The test year expense projection is a weighted average of the 2025 (16%) and 2026 (84%) forecast amounts, which reflect the Company's historical experience of program expense timing.

Field Operations

Q. Please describe the O&M expenses related to the Field Operations Expenses sub-program.

A. The Field Operations Expenses sub-program includes operating employee expenses, telephone/computer chargebacks, environmental fees, gas pipeline user fees, transmission flight operations (aerial surveys), and other miscellaneous expenses.

Primary drivers for this sub-program's expenses are operating employee miscellaneous expenses, pipeline user fees, and permits. Operating employee miscellaneous expenses include items such as costs for mileage, hotels for Company-related trips, permit fees, and telephone and computer charges.

Pipeline user fees are fees paid to the PHMSA section of the United States Department of Transportation for gas distribution and gas transmissions lines. Details regarding the actual O&M expenses in 2023 and the projected test year expenses are provided in the table below:

Table 57

Field Operations Expenses		
Projection Breakdown by Activity Type		
Work Type	**2023 Actual**	**2025-2026 Test year**
Field Ops OM&C Gas Expenses	$1,752,881	$1,433,578
Field Ops OT Meals Gas	$287,835	$320,088
Pipeline User Fees	$696,966	$847,620
Permits	$95,831	$74,640
Gas Field Mobility Exp	$294,525	$347,922
Gas Bonds	$334,514	$600,000
Total Program	**$3,462,552**	**$3,623,848**

Q. What is the basis for determining the $3,623,848 of projected O&M expenses in the test year for this sub-program?

A. The projected test year expense in this sub-program is based on historical spend levels as well as any known work plan needs for the test year period. The reason for this increase in spending is driven primarily by increased bond purchase costs.

Table 58

Field Operations Expenses	
Dollars	
Year	**Dollars**
2016	$4,070,748
2017	$4,039,347
2018	$3,223,396
2019	$3,133,706
2020	$2,964,197
2021	$3,709,349
2022	$3,899,805
2023	$3,462,552
2024 Projected	$3,776,000
2025 Projected	$2,727,234
2025-2026 Test year	$3,623,848

The test year expense projection is a weighted average of the 2025 (9%) and 2026 (91%) forecast amounts, which reflect the Company's historical experience of program expense timing.

Indirect Labor/Labor Variation

Q. Please describe the Indirect Labor/Labor Variation O&M Expense.

A. The Indirect Labor/Labor Variation expense supports the difference between the Company's actual operating employees' wages and the amount of salary cost allocated to work orders, using standard labor rates. Indirect Labor Variation occurs when the Company has labor costs not directly related to a work order, such as travel time between jobs, that has not been allocated to a work order via the indirect labor loading. The Company attempts to clear these account balance variances by year end. Thus, the Company does not project any test year expense in this sub-program.

Supervision/Admin Staff

Q. Please describe the O&M expenses related to the Supervision/Admin Staff sub-program.

A. The Supervision/Admin Staff sub-program provides for the management and administrative personnel for Gas Operations to ensure the safe and effective operation of the gas facilities. Operational supervision helps ensure the safety of crews working in the field as well as the safe execution of work practices.

This section combines the Supervision/Admin Staff - Distribution, Supervision/Admin Staff - Services, and Supervision/Admin Staff - Transmission & Storage sub-programs that are shown individually on Exhibit A-88 (JPP-3) page 1, lines 5, 6, and 7.

Q. What is the basis for determining the $5,811,757 of projected O&M expenses in the test year for this sub-program?

A. The projected expense in this sub-program is primarily driven by labor and expenses. In 2021, this program only included employees from Gas Service and Gas Distribution. During 2022, Gas Transmission and Storage, which encompasses M&R and Pipeline, was added to this sub-program.

In September 2023, the Gas Operations Support and Gas Contractor Oversights Teams, formerly part of the Operations Compliance and Controls sub-program, were added to this sub-program. These departments consist of the following areas focused on enhancing the Company's compliance to regulatory requirements and ensuring proper controls.

The following functions were added to the sub-program:

- OQ and the gas operations certification training program ensure the Company's field workforce is qualified to perform its work obligations on the gas system.

- Management of the Company's operational compliance quality assurance processes and systems for identification of risks and opportunities across the Company's gas facilities and operations. This is accomplished through the implementation of preventative and detective controls to manage compliance with state and federal regulatory requirements and an effectiveness verification approach.

- Contractor oversight and management for construction contractors performing work on behalf of the Company on the gas system. This also includes expenses for technology and standardization to achieve remote inspection, governance around contractor oversight, and sewer/cross bore program.

Effective in 2023, the Distribution program includes the labor, expenses, and chargebacks for these employees. The historical year costs and projected test year costs and headcounts are summarized in the following table:

Table 59

Year (Jan – Dec)	Distribution Headcount	Service Headcount	T&S Headcount	Total Headcount	Dollars
2021	151	NA	27	178	$6,819,841
2022	102	48	24	174	$5,345,649
2023	117	47	15	179	$5,576,984
2024 Projected	115	45	18	178	$5,515,440
2025 Projected	115	46	18	179	$5,676,659
2025-2026 Test year	115	46	18	179	$5,811,757

Headcount is expected to be flat from 2023 through the test year. The test year expense projection for the test year is a weighted average of the 2025 (17%) and 2026 (83%) forecast amounts, which reflect the Company's historical experience of program expense timing.

Dispatch & Scheduling

Q. Please describe the O&M expenses related to the Dispatch & Scheduling sub-program.

A. The Dispatch & Scheduling sub-program includes the labor and expenses for personnel who are responsible for efficiency and consistency in statewide scheduling and assignment of emergent, compliance, and customer requested work.

The Dispatching function operates 24 hours per day, 365 days per year in three locations across the state. The Scheduling and Meter Reading support operates during normal business hours and the associated overtime hours as work volume fluctuates throughout the year.

Emergent work consists of odor response investigations, emergent leak repairs, and third-party damage response and repair.

Compliance work consists of work order coordination, creation, and assignment of gas meter routine exchange program, and planned leak and non-leak maintenance work.

Customer-requested work consists of meter turn on/off, seal for nonpayment turn on, issue investigations, and meter upgrades.

This sub-program is also responsible for assigning meter reading routes to technicians and associated troubleshooting. Additionally, it is also responsible for the gas meter Consecutive Estimate Program, which manages customer accounts (approximately 1,000) with three or more consecutive estimates through an escalation process. Escalation includes tracking and reporting of accounts, manual and automated phone calls, postcard and letter mailings, scheduling of appointments, and coordination with other departments

and customers to resolve meter access issues. The actual O&M expenses in 2023 and the projected test year expenses are provided in the table below:

Table 60

Dispatch and Scheduling		
Projection Breakdown by Activity Type		
Work Type	**2023 Actual**	**2025-2026 Test year**
Dispatch and Scheduling	$1,179,714	$1,278,488
Total Program	$1,179,714	$1,278,488

Q. What is the basis for determining the $1,278,488 for Scheduling and Dispatch expenses in the test year for this sub-program?

A. The projected expense in this sub-program is primarily driven by customer-requested demand, including short cycle demand, such as emergency and service calls in addition to gas meter reading work assignment and Consecutive Estimate Program activities. Response to customer and emergent demand requires appropriate levels of personnel to plan, schedule, and dispatch the associated work. This sub-program includes the labor costs and expenses for these personnel.

In 2021, this financial program was separated from a larger program with responsibility for the identified work activities and long cycle work planning, scheduling, and closeout.

Table 61

Dispatch and Scheduling Dollars	
Dollars	
Year	**Dollars**
2016	n/a
2017	n/a
2018	n/a
2019	n/a
2020	n/a
2021	$1,465,488
2022	$1,371,650
2023	$1,179,714
2024 Projected	$1,101,852
2025 Projected	$1,239,000
2025-2026 Test year	$1,278,488

The test year expense projection is a weighted average of the 2025 (16%) and 2026 (84%) forecast amounts, which reflect the Company's historical experience of program expense timing.

EIRP

Q. Please describe the O&M expenses related to the EIRP sub-program.

A. These expenses include training for the Company's gas construction workforce, salaries and expenses for the field supervisors and managers, tools, and facilities maintenance. These expenses ensure that the seasonal workforce is properly staffed, trained, and has the necessary tools and facilities.

Table 62

EIRP O&M		
Projection Breakdown by Activity Type		
Work Type	**2023 Actual**	**2025-2026 Test year**
EIRP Supervision & Admin Sal/Exp	$869,933	$945,439 ~~685,299~~
EIRP Tools	$84,056	$41,757
EIRP OM&C Expenses (Non-Labor)	$10,059	$0 ~~260,140~~
EIRP Facilities	$251,148	$271,422
EIRP Labor OM&C Training	$2,132,942	$3,789,331
Total Program	**$3,348,137**	**$5,047,949**

Q. What is the basis for determining the $5,047,948 of projected O&M expenses in the test year for this sub-program?

A. Approximately 75-80% of the expense in this program is the technical training required to ensure the field employees are fully skilled and qualified to complete the EIRP work. This includes initial training for newly hired employees, as well as more advanced training for higher skilled employees. Along with technical training, expenses in this sub-program include annual refresher training covering standards and policy changes, along with safety procedural changes.

The EIRP workforce is one of the largest hiring groups in the Company to meet the demand of the total gas construction activities (including gas asset replacement and relocation programs as well as the Infrastructure Replacement Program). The EIRP workforce continues to experience employees transferring to other operating departments within the Company.

Along with this employee movement, hiring and training are planned to allow for appropriate staffing as the Company implements the NGDP. Based on projections, this will result in increased spending compared to 2023. This increase is due to additional training needed for the complexity of the EIRP work plan, and for training new hires to maintain

the workforce. As the NGDP progresses, this level of staffing and training is expected to moderate.

In addition to training field personnel, this program also equips those employees with necessary tools and facilities. Facility expenses largely consist of the eight Headquarters sites for the group (located in Saginaw, Lansing, Livonia, Macomb, Flint, Midland, Jackson, and Royal Oak). These costs are driven by the planned work activities that are based on the amount of vintage pipe to be replaced. The facility expenses also include the O&M portion of the total lease payment for the facilities. Lease payments are discussed in the testimony of Company witnesses Kristine A. Pascarello and Quentin A. Guinn. This program expense also experiences inflationary effects as nearly all sites are leased or rented.

Leadership oversight of the approximately 550 field employees, including contractors, in the EIRP workforce is necessary to ensure regulatory compliance, provide instruction for field employee training, and confirm OQs are in place. The projected test year costs for this function are consistent with historical expenses. The historical and projected cost summary is shown in the below table:

Table 63

EIRP O&M Dollars	
Year (Jan-Dec)	**Dollars**
2016	$2,309,424
2017	$2,415,780
2018	$1,996,035
2019	$2,496,230
2020	$5,462,735
2021	$3,681,670
2022	$4,370,398
2023	$3,348,137
2024 Projected	$3,051,022
2025 Projected	$3,367,718
2025-2026 Test year	$5,047,948

The test year expense projection is a weighted average of the 2025 (6%) and 2026 (94%) forecast amounts, which reflect the Company's historical experience of program expense timing.

Work Management and Customer Delivery

Q. Please describe the expenses related to the Work Management and Customer Delivery O&M Program shown on Exhibit A-89 (JPP-4).

A. The Gas Operations Performance ("Ops Performance") Department represented a department within the Consumers Energy Operations organization that began in 2017. The Ops Performance team included experts in work planning, project management, scheduling, administration, data analytics, data science, Lean Operating Systems, process engineering, industrial engineering, standards management, and technology. This department consisted of the following functions focused on streamlining processes to achieve first-time quality for our customers:

(1) Work Management Excellence,

(2) Process, Analytics & Technology, and

(3) Industrial Engineering.

In 2024, the Process, Analytics & Technology, and Industrial Engineering departments moved to other organizations within the Company. The Work Management Excellence department remained and was renamed Work Management and Customer Delivery. Their function is described below.

- Work Management and Customer Delivery includes functions for Distribution Planning, Scheduling, Close-Out, Statewide Admin, and Customer Energy Management (CEM) for long-cycle work. Long-cycle work includes new business requests, gas facility relocates, planned maintenance, alterations, demolitions, gas leak repair, and capacity/augmentation.
  - Planning ensures the operating plan adheres to the MPSC-approved business plan for Gas Operations field work.
  - Scheduling ensures field crews have enough work, ready-work, and the right work and resources to complete the work plan.
  - The Close Out and Admin functions ensure technical documentation is accurate and complete, and that the costs of the work settle appropriately to the work orders and comply with Sarbanes-Oxley rules for capital and O&M work.
  - In addition to Planning, Scheduling, Close-Out, and Admin functions, the Work Management and Customer Delivery Team assumed responsibility, costs, and headcount of the Customer Energy Management ("CEM") team from Gas Engineering in 2023 and retained Operations Process and Technology functions.
  - The CEM team is focused on meeting customer needs by providing a single point of contact for customer-requested main, service, and meter installations and alterations. CEM is responsible for ensuring all new customer service requests and customer-requested alterations on the Company's distribution system are coordinated from initiation through completion to meet customer expectations.
  - Within CEM, there are four departmental areas of focus.
    - The Zonal Project Coordination team is responsible for customer interaction and project coordination for all new business gas main extensions in their respective geographical region.

- The Gas Customer Attachment Program ("CAP") team coordinates the completion of projects which expand the natural gas system into areas that are just adjacent to the current system limits, where more concentrated pockets of potential customers are located, and administration of CAP project tracking and CAP payments. Even with the conclusion of proactive CAP main installation in 2019, this team remains intact to facilitate the tracking of projects and administer the CAP payments associated with the previously installed mains and services per the tariff requirements.

- The CEM team is also responsible for "Express Design" services for all residential service requests within subdivisions, workload coordination and balancing, as well as other design support related tasks, including billing, permitting, and inspection. This organizational re-alignment has aligned like work with like work and provides efficiencies in the work management process.

- The Operations Process and Technology teams provide support for process improvement, standardization, and systems used by Gas Operations, for functions such as project management, scheduling, work management, field order management, field call-out, and meter reading. These resources provide subject-matter expertise, performance coaching, documentation, change management, and technology analysis for changes across the work management process to improve the customer experience.

Table 64

Work Management and Customer Delivery		
Projection Breakdown by Activity Type		
Work Type	**2023 Actual**	**2025-2026 Test year**
Work Management and Customer Delivery	$3,005,111	$2,539,000
Total Program	**$3,005,111**	**$2,539,000**

Q. What is the basis for determining the projected $2,539,000 O&M expenses in the test year for this program?

A. The projected expense is primarily the salary and expenses for this team, and other associated costs (such as vendor costs) in support of the Company achieving the objectives previously discussed. To ensure affordability, the Work Management and Customer Delivery program estimates stable costs through the test year, absorbing increases for

inflation. The historical and projected head count and cost summary for this program is shown in the below table.

Table 65

Work Management and Customer Delivery O&M Headcount & Dollars		
Year (Jan-Dec)	**Headcount**	**Dollars**
2021	285	$3,211,000
2022	244	$4,955,000
2023	382	$3,005,111
2024 Projected	331	$2,320,246
2025 Projected	331	$2,502,146
2025-2026 Test year	331	$2,538,660

Gas Operations Management

Q. Please describe the expenses related to the Gas Operations Management O&M Program shown on Exhibit A-89 (JPP-4).

A. The Gas Operations Management Program includes salaries and expenses for Gas Operations executive level management, Gas Operations support for supply chain and material handling, real estate services that support Gas Operations land ROW, leasing, and Company buildings, and environmental support for contaminated soil testing and clean-up, asbestos assessments and removal, and environmental spills testing and clean-up.

Table 66

Gas Operations Management O&M Projection Breakdown by Activity Type		
Work Type	**2023 Actual**	**2025-2026 Test year**
Gas Operations Management	$834,000	$1,668,000
Total Program	**$834,000**	**$1,668,000**

Q. What is the basis for determining the projected $1,668,000 O&M expenses in the test year for this program?

A. The 2023 actual expense for the Gas Operations Management Program was$834,000. The historical actual amount of program expense is detailed by labor and various non-labor expense components in Exhibit A-89 (JPP-4), page 1, line 3, column b.

The Company's projected test year expense is $1,668,000, as shown on Exhibit A-89 (JPP-4), page 2, line 3, column (j). The projected test year increase from 2023 actual expense is primarily the result of an increase of labor costs to this program. The historical and projected cost summary is shown in the below table:

Table 67

Gas Operations Management O&M Dollars	
Year	**Dollars**
2016	$2,195,460
2017	$922,551
2018	$964,737
2019	$1,212,544
2020	$1,943,237
2021	$1,580,115
2022	$2,094,000
2023	$834,000
2024 Projected	$1,700,542
2025 Projected	$1,643,461
2025-2026 Test year	$1,668,023

IT PROJECTS

Q. Is the Company planning IT projects that support the engineering, asset planning, design, construction, and maintenance of a safe, reliable, and affordable natural gas distribution system for its customers?

A. Yes. Company witness Stacy H. Baker includes in her direct testimony and exhibits a number of technology projects that are critically important in supporting these gas functions within the Company. The expenditures for these projects are contained within the exhibits sponsored by Ms. Baker. The project providing customer benefits for the areas which I am sponsoring are described below:

- The **Standard Work Plan** project requires $137,388 in O&M in the test year.

  Description: The Gas and Electric Resource Planning process is solely reliant on spreadsheets and manual data collection from numerous, disparate sources. It is not only time-consuming but also prone to errors, leading to potential inefficiencies in resource allocation and a lack of detailed, insightful planning. The sole use of spreadsheets makes analyses and what-if scenario development cumbersome. The lack of workplan controls contributes to the completion of pull-ahead work resulting in unnecessary OT and contractor expense. Implementing a centralized planning platform that will interface with existing systems like SAP, DAPP, and EAM Dashboard would transform our planning organization, offering a clear view of planned work and ensuring that executed work is aligned with strategic objectives. In addition, a more integrated system that leverages automation and real-time data analytics would allow for the immediate, what-if scenario planning the business needs to support sound, data-driven decision-making. The tool, alongside necessary process and system enhancements will streamline the workflow and ultimately lead to schedule quality and ensure prudent overtime and contractor usage through reducing the amount of unplanned work breaking into the work management process. A shift to a digital solution that fully aligns resources, work units and feeds the schedule will represent a significant step forward in resource management, aligning with modern best practices.

  Problem Statement: The Gas and Electric Resource Planning process is solely reliant on spreadsheets and manual data collection from numerous, disparate sources. It is not only time-consuming but also prone to errors, leading to potential inefficiencies in resource allocation and a lack of detailed, insightful planning. The sole use of spreadsheets makes analyses and what-if scenario development cumbersome. The lack of workplan controls contributes to the

completion of pull-ahead work resulting in unnecessary OT and contractor expense.

Objectives: The project will add value by: (1) improving Work Planning Annual Forecast Process: This involves the enhancement of automated inputs, processing, and reporting with a shift towards a more asset-driven prioritization method; (2) converting Monthly Work Plans into Weekly Schedules: Establish a process that seamlessly transforms monthly work plans into executable weekly schedules for easy handoff from planning to scheduling; (3) providing the ability to Run Forecasting and Planning Scenarios: Execute forecasting and planning scenarios and provide comparative analysis; (4) improve system visibility of Work Planned jobs increasing forecast accuracy of downstream processes; and (5) creating multiple dashboards based on the audience of the data providing visibility across all levels of Operations Leadership as well as Supply Chain proactively informing of upcoming workload, potential gaps, opportunities for contingencies if levers are pulled, and clean executable work keeping our workforce fully engaged and productive. This results in improved Field Operations and Customer Satisfaction with delivery commitments and meeting reliability and compliance dates.

Scope: The project scope includes the following: (1) developing a system for Work Planning Annual and Monthly forecast with automation; (2) creating the ability to translate the Monthly forecast into an executable Weekly Schedule; (3) creating technology for running Planning Scenarios with ability to compare scenarios for optimized field execution; (4) improving system visibility of Work Planned jobs increasing forecast accuracy of downstream processes (ie. materials); and (5) building Dashboards and reports to provide visibility and help management maintain process control.

Alternatives: Alternatives considered: (1) Purchase commercially available system. This option was not selected as a single all-encompassing system does not link the Annual forecasting to execution. Products reviewed included Prometheus. (2) Microsoft Excel based solution. Extending the Microsoft Excel based solution was not selected as it did not provide the level of data integration for controlling a large number of forecasted work items. (3) Development of a system that integrates with our SAP investment. This option was not selected as it does not align to expected value delivery timeline. (4) Purchase a SaaS solution to enable planning and forecasting with integration to our SAP work management system. The fourth alternative was selected because it aligns to the expected value delivery timeline and meets the functional requirements.

Q. Does this complete your direct testimony?

A. Yes. The Gas Operations Division is committed to meeting the needs of Consumers Energy's 1.8 million natural gas customers by consistently delivering services safely and

efficiently. The Company's proactive approaches to Gas Operations, Maintenance and Metering, Field Operations, Operations Performance, and Operations Management, ensure that the Company adequately prepares for the future circumstances required to continue serving the needs of customers and the communities in which they live.

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

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

REVISED DIRECT TESTIMONY

OF

LINCOLN D. WARRINER

ON BEHALF OF

CONSUMERS ENERGY COMPANY

December 2024

Q. Please state your name and business address.

A. My name is Lincoln D. Warriner, and my business address is 1945 West Parnall Road, Jackson, Michigan 49201.

Q. By whom are you employed?

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

Q. What is your current position with Consumers Energy?

A. My current position is Senior Strategy Manager in the Gas Engineering and Supply Department.

Q. What are your responsibilities as Senior Strategy Manager?

A. I assist the Gas Engineering and Supply and Gas Operations departments with asset lifecycle oversight, guidance, and leadership of the Natural Gas Delivery Plan ("NGDP") development, implementation, recovery, and verification of results focused on the Company's investment and operation of gas distribution assets.

Q. Please describe your professional work experience?

A. I have been employed by Consumers Energy for more than 37 years. I was promoted to the position of Senior Strategy Manager in Gas Engineering and Supply during 2021. My experience with the Company is summarized as follows:

I began working for the Company in June 1987 as a Region Accountant at the Grand Rapids Service Center. While there, I performed various reviews of internal accounting control procedures and workflow processes. In 1989, I transferred to a similar position at the Lansing Service Center. In 1991, I took a position as a Management Systems and Planning Analyst in the Southern Region Administration and Planning Department. My primary responsibility in this position was to provide analytical support to region

management on issues concerning Operating and Maintenance ("O&M") and construction budgets and other performance measurements. In February 1994, I took a position as an Administrative Supervisor responsible for the supervision of several administrative functions including region accounts payable, miscellaneous accounts receivable, cash receipts and disbursements, payroll, records center, and mail room operations. In February 1995, I transferred to the Electric Strategic Business Unit ("SBU") Planning Department, which was subsequently consolidated within the Rates and Business Support Department. In that department, I was responsible for coordinating the development of financial plans, budgets, analysis, and forecasts for the Electric SBU. My responsibilities expanded within the Rates and Business Support Department to include the electric deliveries and peak demand forecasts, as well as supervisory responsibility for the Company's electric revenue forecasts and gas deliveries forecasts. In October 2012, I accepted a new position supporting the Smart Energy Development Project by maintaining the project business case, evaluating the estimated costs and benefits of the project, partnering with operating departments to plan for the realization of project benefits, and providing analytical support for various regulatory filings. In January 2016, I accepted a new position as a Financial Benchmarking Analyst in the Economic Portfolio Management Section of the Distribution Operations, Engineering, and Transmission Department. In this roll, I supported the Company's strategic capital allocation, long-term financial planning, and annual budgeting and forecasting processes. In July 2017, my position transitioned into the Rate Case/Controls section of the Gas Strategy Department to provide support for Company witnesses with the development of testimony and exhibits and assist in responding to data requests that occur during audit and discovery phases of general rate cases. I was promoted

to my current position in 2021 to assist with gas distribution asset strategy planning and implementation.

Q. Please describe your educational background.

A. I received a Bachelor of Science Degree in Business Administration with a major in Accounting from Central Michigan University in 1987. In 1994, I received a Master of Science in Administration Degree from Central Michigan University.

Q. Have you testified in other cases before the Michigan Public Service Commission ("MPSC" or the "Commission")?

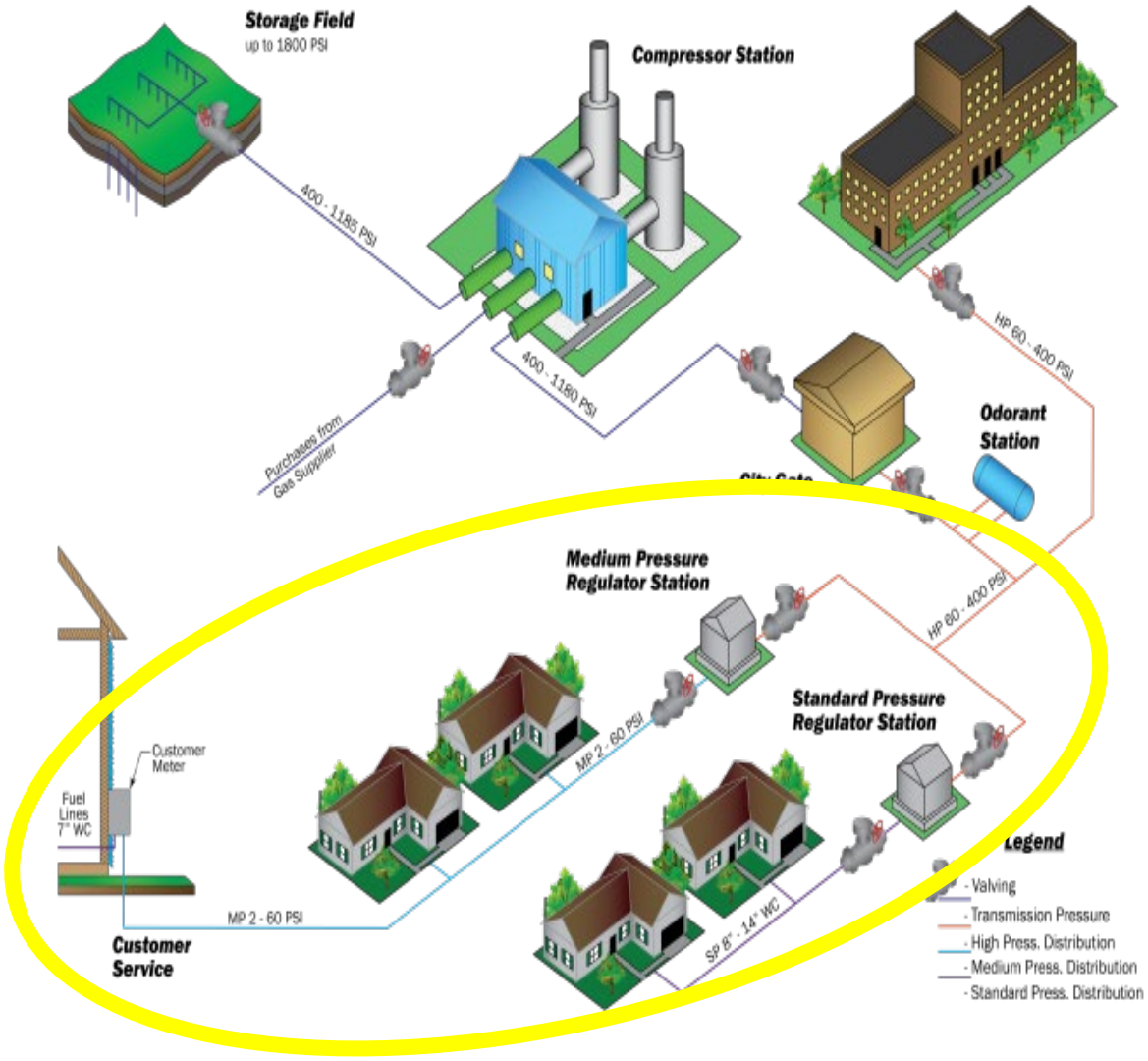
A. Yes. I have provided testimony in the following Case Nos.:

- Case No. U-16191 – January 2010 Electric Rate Case;
- Case No. U-16412 – September 2010 Energy Optimization Plan Amendment;
- Case No. U-16418 – August 2010 Gas Rate Case;
- Case No. U-16432 – September 2010 Power Supply Cost Recovery ("PSCR") Plan Case;
- Case No. U-16543 – February 2011 Renewable Energy Plan Amendment;
- Case No. U-16794 – June 2011 Electric Rate Case;
- Case No. U-16670 – August 2011 Energy Optimization Plan Amendment;
- Case No. U-16890 – September 2011 and February 2012 PSCR Plan Case;
- Case No. U-16924 – December 2011 Gas Cost Recovery Plan Case;
- Case No. U-17087 – September 2012 Electric Rate Case;
- Case No. U-17095 – September 2012 PSCR Plan Case;
- Case No. U-17429 – July 2013 Certificate of Necessity Filing for the Thetford Generating Plant;
- Case No. U-17643 – July 2014 Gas Rate Case;
- Case No. U-17735 – December 2014 Electric Rate Case;

- Case No. U-17882 – July 2015 Gas Rate Case;
- Case No. U-17990 – March 2016 Electric Rate Case;
- Case No. U-17087 Remand – June 2016 Remand Electric Rate Case;
- Case No. U-18124 – August 2016 Gas Rate Case;
- Case No. U-18322 – March 2017 Electric Rate Case;
- Case No. U-20134 – May 2018 Electric Rate Case;
- Case No. U-20697 – February 2020 Electric Rate Case;
- Case No. U-21308 – December 2022 Gas Rate Case; and
- Case No. U-21490 – December 2023 Gas Rate Case.

Q. What is the purpose of your direct testimony?

A. The purpose of my direct testimony is to explain the Company's request for rate relief as it relates to certain gas distribution capital investments that are intended to keep the system safe and reliable while providing affordable and clean energy to customers. The distribution assets are the portion of the Company system that receives the gas at the outlet of the Company's city gates and delivers the gas to customers. In the diagram below, these assets are inside the yellow highlighted section.



The capital expenditures described in my testimony are primarily related to the installation and replacement of the Company's gas mains, services, and meters downstream of the city gates. These investments will support the continued safe delivery of gas to customers through this infrastructure. I will also briefly discuss the information technology ("IT") projects that are critically important to support these gas functions within the Company. These IT projects are fully developed, presented, and supported by Company witness Stacy H. Baker.

Q. How does your direct testimony relate to the NGDP presented by Company witness Neal P. Dreisig?

A. Mr. Dreisig's direct testimony discusses the Company's NGDP. My direct testimony contains elements that support the objectives of the NGDP: providing gas supply that is safe, reliable, affordable, and clean. The distribution capital programs represented in my direct testimony work toward achieving the NGDP's objectives of providing safe and reliable service to both new and existing customers within the Company's natural gas service area.

Q. How does the scope of your testimony compare to the testimony you provided in the Company's last gas rate case (Case No. U-21490)?

A. The capital programs described in my testimony are the same as the capital programs I sponsored in Case No. U-21490.

Q. Are you sponsoring any exhibits?

A. Yes. I am sponsoring the following exhibits:

Exhibit A-12 (LDW-1)	Schedule B-5.9	Projected Capital Expenditures, Distribution Plant, Summary of Actual & Projected Gas and Common Capital Expenditures;
Exhibit A-101 (LDW-2)		Actual & Projected Gas Capital Expenditures - New Business Program;
Exhibit A-102 (LDW-3)		Actual & Projected Gas Capital Expenditures - Asset Relocation Program;
Exhibit A-103 (LDW-4)		Actual & Projected Gas Capital Expenditures - Regulatory Compliance Program;
Exhibit A-104 (LDW-5)		Actual & Projected Gas Capital Expenditures – Capacity/ Deliverability Program; and

Exhibit A-105 (LDW-6) — Projected Capital Expenditures – Transmission & Distribution Plant, Summary of Actual & Projected Gas Capital Expenditures.

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

A. Yes.

Q. Please summarize your direct testimony.

A. My direct testimony explains the Company's projections of certain Gas Distribution capital program investments through October 31, 2026, which are displayed on Exhibit A-12 (LDW-1), Schedule B-5.9. The total Gas Distribution capital expenditures supported by this direct testimony are as follows:

- Calendar year 2023 actual capital expenditures of $212,938,276, as displayed on line 5, column (b), of Exhibit A-12 (LDW-1), Schedule B-5.9;
- Calendar year 2024 projected capital expenditures of $204,595,685, as displayed on line 5, column (c), of Exhibit A-12 (LDW-1), Schedule B-5.9;
- Ten months ending October 31, 2025 projected capital expenditures of $227,215,170, as displayed on line 5, column (d), of Exhibit A-12 (LDW-1) Schedule B-5.9; and
- Projected test year 12 months ending October 31, 2026 capital expenditures of $321,119,320, as displayed on line 5, column (f), of Exhibit A-12 (LDW-1), Schedule B-5.9.

These expenditures are also shown in Table 1 below.

Table 1: Gas Distribution Capital Expenditures (in thousands of dollars)

Program Description	Historical 12 Mos Ended 12/31/2023	12 Mos Ending 12/31/2024	10 Mos Ending 10/31/2025	22 Mos Ending 10/31/2025	Projected Test Year 12 Mos Ending 10/31/2026
New Business	76,320	65,048	52,654	117,702	66,645
Asset Relocation	97,685	86,838	75,838	162,676	98,809
Regulatory Compliance	34,488	45,217	91,704	136,920	150,311
Capacity/Deliverability	4,446	7,493	7,019	14,512	5,354
Total Capital	**212,938**	**204,596**	**227,215**	**431,811**	**321,119**

I. GAS DISTRIBUTION CAPITAL EXPENDITURES

Q. Please highlight the change in test year capital expenditures compared to the historical actual capital expenditures incurred by the Company in calendar year 2022.

A. The projected test year capital expenditures of $321.119 million are $108.181 million more than the $212.938 million actually incurred in calendar year 2023. The increase or decrease for each program is summarized below:

- New Business: a decrease of $9.675 million, or approximately 12.7%;
- Asset Relocation: an increase of $1.124 million, or approximately 1.2%;
- Regulatory Compliance: an increase of $115.823 million, or approximately 335.8%; and
- Capacity/Deliverability: an increase of $0.908 million, or approximately 20.4%.

As indicated above, the increase in Regulatory Compliance expenditures accounts for most of the increase in test year capital expenditures compared to the 2023 historical actual.

Q. How much of a difference was there between the 2023 actual capital expenditures for these programs and the five-year average amount?

A. The 2019-2023 five-year average amount is $212.9 million, and the 2023 actual amount is $212.9 million, so the 2023 actual capital expenditures were approximately equal to the five-year average. Table 2 provides the actual capital expenditures for 2019 through 2023 for each program, as well as the corresponding five-year average amount.

Table 2: Gas Distribution Capital Expenditures – 5 Year History (in thousands of dollars)

Program Description	Historical 2019	Historical 2020	Historical 2021	Historical 2022	Historical 2023	Five Year Historical Average
New Business	86,498	87,021	55,373	74,088	**76,320**	**75,860**
Asset Relocation	106,363	83,973	63,376	116,504	**97,685**	**93,580**
Regulatory Compliance	46,318	38,354	46,994	22,832	**34,488**	**37,797**
Capacity/Deliverability	3,560	3,599	6,503	10,196	**4,446**	**5,661**
Total Capital	**242,739**	**212,947**	**172,246**	**223,620**	**212,938**	**212,898**

Q. Please summarize the change in test year capital expenditures compared to the historical five-year average actual capital expenditures incurred by the Company in 2019-2023.

A. The projected test year capital expenditures of $321.119 million are $108.221 million more than the historical five-year average amount of $212.898 million, which represents an increase of approximately 24%.

Q. Please describe the primary changes in test year capital expenditures compared to the historical actual capital expenditures incurred by the Company in 2019-2023.

A. The projected test year capital amount of $321.119 million exceeds both the 2023 historical actual and the historical five-year average. The increase can be attributed to five specific Regulatory Compliance projects that account for ~~$103.1~~ $106.991 million of the Company's projected test year capital expenditures. These include:

- $39.362 ~~35.453~~ million of test year capital expenditures for the Line 1002c Macomb & Oakland County Maximum Allowable Operating Pressure ("MAOP") project;
- $33.151~~175~~ million of test year capital expenditures for the Line 1022 Airport Road MAOP project;
- $17.417 ~~430~~ million of test year capital expenditures for the Line 1093 Shattuck Road MAOP project;

- $9.024 ~~031~~ million of test year capital expenditures for the Line 1026f Mt Hope Road MAOP project; and
- $8.036 ~~042~~ million of test year capital expenditures for the Line 1009/1009c Phase 3 Little Mack - 10 mile to 9 mile, Macomb County MAOP project.

These specific projects are described in more detail within my testimony on the MAOP-Distribution sub-program.

Q. Please describe the approach used to project the Company's Gas Distribution capital expenditures for the years 2023 through the 12 months ending September 30, 2025.

A. The projected capital expenditures for this period are based on projected costs for individual projects and sub-programs necessary to ensure customer safety, meet regulatory requirements, and provide reliable service to customers. The projection methodologies vary among the different sub-programs and are described in more detail within each respective section throughout my direct testimony. The 2024 projections include actual expenditures for January through August of 2024 and estimates of expenditures for September through December of 2024. Projections of annual 2025 and 2026 capital expenditures were used in combination with historical spending patterns to estimate the dollars for the ten months ending October 31, 2025, and the test year period of November 1, 2025, through October 31, 2026. In a few instances, monthly estimates were made with input from subject matter experts if historical actual spending patterns did not provide a reasonable basis for estimating the timing of 2025 and 2026 expenditures.

Q. Please describe the Gas Distribution programs and sub-programs included within the scope of your testimony and exhibits.

A. The programs, as shown on Exhibit A-12 (LDW-1), Schedule B-5.9, are:

- New Business;
- Asset Relocation;

- Regulatory Compliance; and
- Capacity/Deliverability.

Each program includes sub-programs that provide additional detail for each program, as shown on Exhibit A-101 (LDW-2) through Exhibit A-105 (LDW-6):

- New Business
  - Mains, Services & Meter Stands – Distribution
  - Large New Business Projects – Distribution
  - Customer Attachment Program - Distribution
- Asset Relocation
  - Asset Relocation – Civic Improvement
  - Asset Relocation - Reimbursable
- Regulatory Compliance
  - Regulatory Base – Distribution
  - Meters
  - MAOP – Distribution
  - Cathodic - Distribution
- Capacity/Deliverability
  - Augment - Distribution

Many of these programs have a gas distribution and a gas transmission component to them. My direct testimony represents the gas distribution portion of these programs. The direct testimony of Company witnesses Michael P. Griffin, Neal P. Dreisig, and Timothy K. Joyce represent additional components of the gas transmission system as well as distribution regulating stations, compression, and storage systems. The direct testimony of Company witness Pascarello represents gas distribution system capital expenditures associated with the Company's Material Condition Program and the Gas Operations Other Program.

Q. Have you included contingency costs in the capital expenditures you are sponsoring?

A. No, there are not any contingency costs included in the capital expenditures.

A. New Business

Q. Please describe the capital expenditures related to the New Business Program as shown on Exhibit A-12 (LDW-1), Schedule B-5.9, line 1.

A. The New Business Program consists of the capital costs of adding new commercial, industrial, and residential customers to the Company's distribution system. The program costs include the cost of installing mains and services, and the cost of meter stands to service new customers. These projects are required in response to customer requests for new gas use at their site. Customers requesting a new connection are asked to pay for a portion of the cost to construct these projects. The amount paid by a customer is referred to as a "contribution in aid of construction" or "CIAC." The total New Business capital expenditures (net of customer contributions) that the Company experienced in 2023, and the Company's projections for the years 2024, the ten months ending October 31, 2025, and the 12-month test year ending October 31, 2026, are displayed in total on Exhibit A-12 (LDW-1), Schedule B-5.9 on line 1, columns (b) through (f), respectively. These expenditures are also shown in Table 3 below, with amounts for each sub-program identified.

Table 3: New Business Program Capital Expenditures (expressed in thousands of dollars)

Program Description	Historical 12 Mos Ended 12/31/2023	12 Mos Ending 12/31/2024	10 Mos Ending 10/31/2025	22 Mos Ending 10/31/2025	Projected Test Year 12 Mos Ending 10/31/2026
Mains, Services, Meter Stands	66,760	55,338	49,596	104,934	61,682
Large New Business Projects	9,371	9,710	3,058	12,768	4,963
Customer Attachment Program	188	0	0	0	0
Total New Business	**76,320**	**65,048**	**52,654**	**117,702**	**66,645**

Exhibit A-101 (LDW-2) provides further details of the expenditures included in this program.

Q. Please identify any regulatory standards related to the Company's gas new business connection process.

A. Michigan Administrative Code Section R 460.2371 contains safety and service quality standards for gas utilities. Specific provisions include:

- A utility shall establish gas service to a customer's premises in compliance with the Michigan gas safety standards; and
- If there is an existing main at a requesting address, a utility shall complete 90% or more of its new service installations within 15 business days of customer payment per tariff requirements and site readiness, or by a later date that is mutually agreed upon between the utility and customer.

The Company implemented plans during 2023 to address performance impacts associated with construction material delivery delays as well as other root causes of service installation delays. The Company's plans for improving performance results are detailed in the August 4, 2023 document filed in Case No. U-21458 titled "Consumers Energy Company's Report on Meter Malfunctions, Estimated Billing Practices, and Delays in New Service"[1]. The Company has been meeting the new gas service installation factor standard each month since June 2023.

Q. What is the Company's current projection for gas new business service connections?

A. The Company's projects 6,800 gas new business service connections during calendar year 2024 and again during calendar year 2025, then 7,000 gas new business service connections in 2026. The twelve-month ending October 31, 2026 test year forecast is 6,964 services.

[1] The referenced report is available on the Michigan Public Service Commission's website at the following location: https://mi-psc.my.site.com/sfc/servlet.shepherd/version/download/0688y0000094k46AAA

These projections are significantly reduced compared to the average for the 2019 through 2023 time period of 7,582 gas service installations. The variance between the test year projection and the five-year average is 618 services, or about 8.2% less than the five-year average.

Q. Please explain the growth in the Company's gas new business connection projections.

A. The Company's Customer Energy Management Department uses data from multiple sources to project and plan for new business growth.

Internal data regarding the installation of new gas services is one important source of data used to understand trends impacting the Company's investments in the new business program. During the five-year period of 2015 through 2019, the Company had experienced an average new gas service installation rate of approximately 9,100 new gas services installed per year.[2] 2019 was the last full year prior to the COVID-19 pandemic, and the Company installed 8,223 new gas service units in that year. During 2020, new gas service installations declined from 2019 by 987 units (or 12.0%) to 7,236 units.[3] During 2021, new gas service installations increased from 2020 by 625 units (or 8.6%) to 7,861 units. During 2022, new gas service installations declined by 142 units (or 1.8%) to 7,719 units. 2023 new gas service installations also declined 849 units (or 11.0%) compared to 2022. As a result, the Company has revised its long-range outlook for new gas service installation activity downward from prior forecasts.

[2] Historical new gas service installations per year were: 2015 – 9,943; 2016 – 9,422; 2017 – 8,482; 2018 – 9,423; 2019 – 8,223. The average for these five years is calculated as (9,943+9,422+8,482+9,423+8,223)/5 = 9,098.6.

[3] As noted in the footnote above, new gas service installations in 2019 totaled 8,223 units.

The Customer Energy Management Department also monitors the projections of the Michigan Home Builders Association ("HBA of Michigan" or "HBA"). In January of 2024, the HBA of Michigan revised their projections of calendar year single family home permits to 14,330 units in 2023 and 13,964 units in 2024.[4] The 2023 unit projection was decreased by 1,216 units, or 7.8% from the HBA of Michigan's June 2023 forecast of 15,546 units for 2023.

The Company's projected service installations for 2024 and 2025 of 6,800 units reflect an anticipated decrease of 70 units compared to 2022, a decline of approximately 1.0%. Therefore, the service installation projections provided the Company's Customer Energy Management Department reflect slightly slower decline in 2024 than the HBA of Michigan projection.

The Company also subscribes to economic projections published by S&P Global ("S&P"). The Summary of the U.S. Economy, published by S&P is provided as a workpaper in this case by Company witness Heather L. Rayl.[5] The June 2024 forecast of total housing starts for the U.S. economy indicates an expectation that 2024 housing starts will be 1.373 million units, then increase slightly to 1.379 million units in 2025, and then increase to 1.400 million units in 2026. Despite the projected decline between 2023 and 2024, the 2024 to 2026 annual U.S. housing start forecasts all exceed the actual 2019

[4] Source: https://hbaofmichigan.com/assets/pdf/HBAM+2024+Permit+Forecast/ press release dated January 3, 2024, "2024 Production Forecast: Flat Market Continues"

[5] Workpaper reference: WP-HLR-33.

pre-pandemic measure of 1.292 million units as well as the 2016 to 2020 five-year average of 1.264 million units.[6]

Q. Do you have any further comment on the level of new business program activity that should be considered when evaluating the Company's projections of new business capital expenditures?

A. Yes. The Company's service installation projection includes customer conversions to natural gas under the Customer Attachment Program ("CAP"), which are expected to be relatively small in volume going forward, as well as new connections that are typically requested during building construction. Some of these new connections are expected to be located along existing gas main facilities, while others will require some extension of the distribution main network.

The Company experienced a significant increase in the amount of new business work associated with extending distribution mains in the 2023 historical year compared to the 2022 calendar year. The extension of distribution mains required investments of approximately $28.6 million during 2023. In comparison, the Company's investments to extend distribution mains were $18.1 million during the entire calendar year of 2022 and $11.7 during calendar year 2021. In addition to new residential subdivision developments, the Company has made investments to extend mains to a variety of customers, including the following examples:

- Battery Cell manufacturing and other manufacturing operations;
- Electricity generation operations;
- Renewable Natural Gas ("RNG") operations;
- Other agricultural facilities;

[6] Calculation of 2016-2020 average: [1.177 million units in 2016 + 1.205 million units in 2017 + 1.247 million units in 2018 + 1.292 million units in 2019 + 1.397 million units in 2020]/5 = 1.264 million units

- Manufactured home community developments; and
- Health care facility additions and expansions.

Q. Have the Company's current projections of New Business service attachments decreased from the projections provided by the Company in Case No. U-21490?

A. Yes, the new service attachment projections in this case are lower than the new service attachment projections in my testimony from Case No. U-21490. A comparison of New Business service attachments in each proceeding are provided below:

Table 4: New Business Program service attachment projections

Description	Historical 2023	Projected 2024	Projected 2025	Projected 2026
Case No. U-21490[7]	8,155	8,318	8,318	8,318
Current Projection (Case No. U-21806)	6,870	6,800	6,800	7,000
Difference (in units)	-1,285	-1,518	-1,518	-1,318
Difference (in percent)	**-15.8%**	**-18.2%**	**-18.2%**	**-15.8%**

Q. How many feet of gas distribution main have historically been installed as part of the Company's New Business Program?

A. During the time period of calendar years 2019 through 2023, the Company installed approximately 345.0 miles of gas main,[8] or an average of approximately 69.0 miles per year. The gas main installed during the 2023 historical year in this case is 68.1 miles, which is approximately 99% of the five-year average. During the January to September 2024 time frame, the Company installed 35.1 miles of distribution main and will likely

[7] Source: Case No. U-21490 Direct Testimony of Company witness Lincoln D. Warriner, page 17, Table 4.

[8] Historical gas main installation miles: 2019: 91.3 miles; 2020: 61.6 miles; 2021: 52.8 miles; 2022: 71.2 miles; 2023: 68.1 miles The five-year average is calculated as follows: (91.3 + 61.6 + 52.8 + 71.2+68.1)/5 = 345.0/5 = 69

install approximately 49 miles of distribution main for the full year of 2024, or approximately 71% of the five-year average.[9]

Q. What was the actual average New Business Program cost per service installed during the 2023 historical year?

A. I have calculated the average New Business Program cost per service installed during 2023 to be $9,745.01. This number was calculated using the total 2023 actual New Business Program capital expenditures of $76,319,516, less the expenditures for New Business Major Projects of $9,371,293; or $66,948,223 divided by the number of New Business services installed during 2022 of 6,870 units.

Q. What are the projected average New Business Program cost per service installed for 2024, 2025, and 2026?

A. The projected New Business Program units and unit costs are provided in Table 5 below. In addition to showing the projected units and unit costs for each calendar year, Table 5 also documents the calculation of the test year dollars for the New Business Program. The projected capital expenditures for November through December of 2025 are 17.6% of the 2025 annual projection, and the projected capital expenditures for January through October of 2026 are 80.6% of the 2026 annual projection.

[9] The 2024 estimate of approximately 49 miles is based on October 2023 through September 2024 actual experience of 48.9 miles (or 258,227 feet).

Table 5: New Business Units and Unit Costs (in Thousands of Dollars)

Description	Actual 2023	Projected Calendar Year 2024	Projected Calendar Year 2025	Projected Calendar Year 2026	Projected Test Year
Total New Business Dollars (in Thousands; excluding Large New Business projects)	**$66,948**	**$55,332**	**$60,182**	**$63,368**	[redacted]
Service Installation Units	6,870	6,800	6,800	7,000	
Average Unit Cost (in $)	$9,745.01	$8,137.05	$8,850.26	$9,052.62	
Test Year Dollar Detail:					
Calendar Year amounts included in the Projected Test Year (in Thousands)	[redacted]		**$ 10,586 (November through December)**	**$ 51,096 (January through October)**	**$61,682**

Q. Please explain the difference between the projected unit costs shown above, and the 2023 actual unit cost of $9,745.01.

A. The 2026 projected unit cost of $9,052.62 is less than what would be expected if S&P forecasts of Consumer Price escalation were used to project the 2023 unit cost forward out to 2026. The 2026 projected unit cost in a Consumer Price escalation scenario would be $10,555.67, which is an increase of $1,503.05 per unit, or 16.6% from the Company's 2026 projection.[10]

The 2025 projected unit cost of $8,850.26 is less than what would be expected if S&P forecasts of Consumer Price escalation were used to project the 2023 unit cost forward out to 2025. The 2025 unit cost in a Consumer Price escalation scenario would be

[10] The projected Consumer Price inflation projections for 2024, 2025, and 2026 respectively are 3.2%, 2.4%, and 2.5%. The 2023 actual unit cost of $9,745.01 x 1.032 (2024 Consumer Price Index "CPI" growth) x 1.024 (2025 CPI growth) x 1.025 (2026 CPI growth) = 10,555.67. Alternatively, the average of the 2024, 2025, and 2026 Consumer Price inflation projections is 2.7%; therefore, the calculated 2026 unit cost estimate based on the average inflation projection would be $9,745.01 x 1.027 x 1.027 x 1.027 = $10,555.86. The CPI growth rates used in this calculation are documented in WP-HLR-33.

$10,298.22,[11] which is an increase of $1,447.96 per unit, or 16.4% from the Company's 2024 projection.

The 2025 projected unit cost of $8,850.26 is equivalent to decreasing the 2023 actual average unit cost at 4.7% per year.[12] The 2025 projected unit cost are lower than the 2023 actual amount due to constraints on the Company's total forecasted dollars for the New Business Program based on the direct testimony of MPSC Staff ("Staff") witness Cynthia L. Creisher in Case No. U-21490, which estimated test year ending September 30, 2025 New Business Program capital expenditures of $63.2 million.[13]

The 2024 projected unit cost of $8,137.05 is less than what would be expected based on S&P forecasts of Consumer Price escalation were used to project the 2023 unit cost forward to 2024. The 2024 projected unit cost in an updated Consumer Price escalation scenario would be $10,056.85, which is an increase of $1,919.80 per unit, or 23.6% from the Company's 2024 projection.

The 2024 projected unit cost of $8,137.05 is 16.5% less than the 2023 actual unit cost. This projection includes eight months of actual expenditures and four months of projected expenditures and reflects decreases in various contractor costs that are being realized during 2024.

[11] 2023 actual unit cost of $9,745.01 x 1.032 (2024 CPI growth) x 1.024 (2025 CPI growth) = $10,298.22. The CPI growth rates used in this calculation are documented in WP-HLR-33.

[12] 2023 actual unit cost of $9,745.01 x 0.95299 x 0.95299 = 8,850.26.

[13] Case No. U-21490, Direct Testimony of Staff witness Creisher, page 16, line 6. Please note that $3.2 million has been allocated to Large New Business for three specific projects during 2025, and the Large New Business dollars are excluded from the calculation of the 2025 projected unit cost.

Q. Please describe the process of connecting customers under the New Business Program.

A. When the Company receives a request for a new connection, the Company documents the customer's location, requested load, and required delivery pressure. The Company's engineering staff then analyzes the existing system to determine the necessary steps to provide gas service to that customer. In each of these cases, the customer will be responsible for the cost of work required to make the connection, including main installation, service installation, permit costs, etc. The determination of the amount of contribution required from each customer, however, will consider projected revenue from the customer, according to the Customer Attachment tariffs, as stated in Rule C8 of the Company's Rate Book for Natural Gas Service (the Company's "Tariff").

Q. What is the status of the Company's CAP sub-program?

A. In 2019, the Company completed the last proactively marketed CAP main installations. The program continues to exist to track the service installations connected to the CAP mains until the associated CAP charges expire, which is 10 years from the date of installation. All new requests that require gas main extensions will continue to be processed according to the Company's Tariff relating to Customer Attachment, as stated in Rule C8 of the Company's Tariff, but the Company is not proactively soliciting to scope and construct additional CAP main extensions. New service connections to existing CAP mains are available with the prorated monthly payment option until expiration of the CAP charges on that system. The actual costs incurred during 2023 are detailed on line 3, column (b) of Exhibit A-101 (LDW-2). Actual CAP program service installation costs

incurred during 2024 are included as part of "Mains Services & Meter Stands – Dist" on line 1, column (c) of Exhibit A-101 (LDW-2).

Q. Please describe the projects in the Large New Business sub-program, represented on Exhibit A-101 (LDW-2), line 2.

A. The Large New Business sub-program includes new customer connection projects where the estimated infrastructure cost exceeds $500,000, the Company plans to enter a facilities agreement for unpredictable operations, or the Company deems it necessary for special tracking and project management and, therefore, included it in a separate sub-program. Projects are generally created under this sub-program when the requesting customer has signed a contract with the Company locking in the load requirements and revenue expectations. As with the New Business Mains and Services sub-program, Company Tariff Rule C8, relating to the Customer Attachment Program, is utilized to determine the Customer's contribution to the total project cost. Large New Business projects that have been constructed during 2023 include a 4.0 mile extension of 4" high pressure steel main to provide natural gas service to a new renewable natural gas facility near Saranac, and a 1.8 mile extension of 8" high pressure steel main to provide natural gas service to a new battery manufacturing facility in Lansing. During 2024 and 2025, the Company is constructing a 1 mile extension of 8" high pressure steel main to serve a battery manufacturing facility in Marshall and an approximately 4,500 foot extension of 6" high pressure steel main in Hemlock to serve a new plant that manufactures components for the solar power industry. The Company is also planning to construct an approximately 200 foot extension of 8" high pressure steel service to serve a natural gas fired electric generation facility expansion in the Lansing area and a 1400 foot extension of 6" high

pressure steel main to serve an industrial site redevelopment in Flint. Currently, there are no specific new projects included in the projections for this sub-program for 2026. New requests for load, however, can be received at any time, meaning the Company may add projects to this program as customer requests materialize. The Company's capital expenditure projection for the test year ending October 31, 2026 includes $4.78 million for unspecified future project capital investments in the Large New Business sub-program.[14] Historically, the Company has invested $67.3 million since 2019 to construct gas service facilities for large customers.[15]

Gas service facilities that have been installed as required to meet customer service requirements include high-pressure gas mains, city gate and regulating station equipment, services, and meter stands. Site restoration costs for these projects are also included in this sub-program. The projects identified in Table 6 below are examples of the Company's efforts to support economic development efforts within Michigan.

[14] The 2026 calendar year projection is $5.07 million, the test year includes the portion expected to be incurred during January through October of 2026.

[15] The historical period referred to in this statement includes January 2019 through September 2024.

Table 6: Large New Business Capital Expenditures – History (in thousands of dollars)

Program Description	Historical 2019	Historical 2020	Historical 2021	Historical 2022	Historical 2023	2024 January through September
Lansing BW&L Delta Energy Park Project	11,160	20,519	1,499	675	-46	
Agriculture Processing Complex Project	10,759	6,256	193	28	166	
Industrial Expansion Project		5,064	766	9		
RNG Facility				4	4,377	-1
Battery Manufacturing Facilities				67	4,875	2,847
Other Large New Business Projects	-4,005	1,601	-51	65		484
Total Capital	**17,914**	**33,440**	**2,406**	**848**	**9,371**	**3,330**

Q. Please explain why the Company is including projections of unspecified Large New Business project capital expenditures in 2026.

A. At the time the Company developed its most recent projections of 2026 capital expenditures, the Company had not received any specific customer requests for main installations in that calendar year. However, the Company's actual experience with recent requests for main installations in 2024 and 2025 is an indicator that it is more likely to receive requests for 2026 construction than to receive no requests at all. Additionally, the Company is also involved in economic development project discussions that have the potential to require construction in 2026. Over the 2019-2023 five-year time period, the Company's average capital investment in Large New Business projects averaged $12.8 million. The Company's 2026 calendar year projection of $5.07 million is approximately 40% of that historical average.

Q. Please conclude your testimony regarding the Company's New Business Program.

A. Based on the evidence provided above, analysis indicates that the Company is prudently planning for New Business Program capital expenditures throughout the bridge period and test year in this proceeding. The Company has reduced the projected volumes of new service installations from Case No. U-21490, and the unit cost projections for the New Business Program are lower than the historical 2023 actual unit cost. The potential exists for cost increases and customer requested main extensions to exceed the Company's forecasts for New Business program investments. Thus, the Company respectfully requests the Commission's agreement with the Company's New Business Program projections as provided in my Exhibit A-101 (LDW-2).

B. Asset Relocation

Q. Please describe the capital expenditures related to the Asset Relocation Program as shown on Exhibit A-12 (LDW-1), Schedule B-5.9, line 2.

A. The Asset Relocation Program includes gas distribution infrastructure replacement projects that are required due to civic improvement activities initiated by federal, state, or local governmental units, or by individual customers with existing gas service. There are two sub-programs within the Asset Relocation Program: Asset Relocation – Civic Improvement and Asset Relocation – Reimbursable. The expenditures for each of these programs are shown in Table 7 below and Exhibit A-102 (LDW-3) provides further details of these expenditures.

Table 7: Asset Relocation Program Capital Expenditures (in thousands of dollars)

Program Description	Historical 12 Mos Ended 12/31/2023	12 Mos Ending 12/31/2024	10 Mos Ending 10/31/2025	22 Mos Ending 10/31/2025	Projected Test Year 12 Mos Ending 10/31/2026
Asset Relocation – Civic Improvement	83,518	64,148	63,612	127,760	82,162
Asset Relocation - Reimbursable	14,167	22,690	12,226	34,916	16,647
Total Asset Relocation	**97,685**	**86,838**	**75,838**	**162,676**	**98,809**

Asset Relocation – Civic Improvement consists of gas relocation work driven by municipal projects to replace or improve aging public infrastructure such as roadways, bridges, sewer lines, water lines, and drainage ditches. If the Company's existing facilities are in the public road right-of-way by permit, and need to be moved to eliminate interference, this is done at the Company's expense.

Asset Relocation – Reimbursable accounts for customer requested capital replacements. This includes scenarios where the customer has added load requiring facility upgrades, asked for relocation of a gas main or replacement of a gas service to accommodate a customer need, or created an unsafe situation requiring capital replacement. In the case of added load, the project is reimbursable by the customer, with the appropriate future revenue costs applied as outlined in the Company's Tariff Rule C8. Other replacements, without added load, within this category can be fully reimbursed by the customer.

Q. Please further describe the expenditures associated with the Asset Relocation – Civic Improvement sub-program.

A. Asset Relocation – Civic Improvement work was recognized by the MPSC as critical work for gas utilities on page 96, section 4.2.1.6 of the September 11, 2019 Statewide Energy

Assessment Final Report in Case No. U-20464 ("SEA"). Repairing and expanding infrastructure continues to be a significant topic of public interest as well as a priority for state policy. According to the 2023 Report Card for Michigan's Infrastructure, which has been published by the Michigan Section of the American Society of Civil Engineers (or "ASCE"), Michigan is making progress in reversing underinvestment in the state's infrastructure. State and Federal funding sources have included $3.5 billion in bond funding from the "Rebuilding Michigan Program" and $4.7 billion from the "Building Michigan Together" plan. The 2021 Bipartisan Infrastructure Law will also provide $11 billion to address needed infrastructure projects. The ASCE's 2023 Michigan Infrastructure Report Card assessment shows modest improvement in the overall grade from a "D+" in the 2018 report card to a "C-" in the 2023 report card. Roads and stormwater infrastructure grades have improved from a "D-" in 2018 to a "D" in 2023. Civic Improvement Relocation projects frequently involve replacement of vintage mains and services, avoid third party damage to non-vintage facilities, and reduce the potential for leaks when infrastructure contractors are working around vintage main. The annual replacement of vintage mains and services are documented as part of Attachment 9 "Non-EIRP Distribution Main Replacement Project Metrics", which is included in the Company's enhanced infrastructure replacement annual reports.

Q. Please summarize the Company's investments in the Asset Relocation – Civic Improvement sub-program over the past five historical calendar years.

A. Asset Relocation – Civic Improvement sub-program investments by the Company over the 2019 to 2023 historical years have totaled $408.3 million. Over 208 miles of distribution main has been installed and more than 10,700 services have been replaced during the 2019

to 2023 time period.[16] The average annual capital investment has been approximately $81.7 million.

In most cases, the civic improvement projects involve replacement of metallic facilities with plastic pipe. For example, during the 2019 to 2023 period, approximately 90% of the retired gas main associated with civic improvement projects were manufactured from metallic pipeline materials. Historically, the Company has been required to replace portions of high-pressure facilities within this program, which requires the installation of steel pipe. Steel pipe installations represent 9.4% of the civic improvement project main installed during the 2019 to 2023 period. This high-pressure work is more expensive and more time consuming than work on the medium pressure system due to the nature of the material and construction methods required.

Table 8 below summarizes the annual Asset Relocation – Civic Improvement sub-program historical activity for the number of projects completed, the footage of gas main installed, and the number of gas services replaced. This table shows a substantial reduction of civic improvement work completed during 2020 and 2021 relative to prior historical experience.

[16] Distribution miles installed and services replaced are reported annually as part of the Company's Gas Enhanced Infrastructure Replacement ("EIRP") Annual Report. Asset Relocation – Civic Improvement projects are included in Attachment 9 of those annual reports.

Table 8: Asset Relocation – Civic Improvement Project History[17]

	2019	2020	2021	2022	2023	5-Year Average
Projects completed	202	124	152	170	122	**154**
Feet of Distribution Main Installed	254,605	169,202	195,305	297,246	181,953	**219,662**
Services Replaced	2,924	1,729	2,377	2,494	1,228	**2,494**

Table 9 identifies specific examples of large Asset Relocation – Civic Improvement projects that have required investments of more than $3 million by the Company over the 2017 through 2023[18] time period. The actual values during 2022 and 2023 reflect large capital expenditure requirements associated with the Mound Road reconstruction project, which is expected to be complete by the end of 2024.[19] Another large civic improvement project is the Iron Belle Trail, which provides bicycling and hiking opportunities on trails that extend more than 2,000 miles from the western tip of Michigan's Upper Peninsula to Belle Isle in Detroit. It has been recently reported that the Iron Belle Trail is 71% complete.[20] In addition, the City of Eastpointe's 9 Mile Road reconstruction and water infrastructure project is planned to occur between 2023 and 2025 and will include the addition of green space, benches, bike paths, and other enhancements that will make 9 Mile Road more pedestrian and bicycle friendly.[21]

[17] Source: Attachment 9 to Gas EIRP Annual Report.

[18] The 2023 amount includes actual capital expenditures for January 2023 through September 2023.

[19] https://www.detroitnews.com/story/news/local/macomb-county/2022/09/15/project-rebuild-mound-road-nearly-40-complete/10386613002/, accessed 11/22/2024.

[20] https://www.michigan.gov/dnr/places/state-trails/iron-belle, accessed 11/22/2024.

[21] https://www.macombdaily.com/2023/03/05/modern-9-plan-encompasses-more-than-road-repaving/, accessed 11/22/2024.

Table 9: Asset Relocation – Civic Improvement Large Project History (in Thousands of Dollars)

	Project Reference	2017	2018	2019	2020	2021	2022	2023	2024 January - September
I-75 & M-46 Reconstruction	16161				$8,994	$76	$39		
M-59 Tipsico Lk to Milford Rd	13821	$4,204	$2,209	$1,876		-$75			
I-75 Segment 3	17080			$2,215	$3,836				
M-24 Phase 2	17113			$2,525	$1,657	$1	-$5		
Marion Ave	18972					$3,755	$146	$55	-$8
Oakland Drive	17037				$3,879	($1)	$39	$49	
Mound Rd 13 to 14 Mile	19952						$5,129	$282	
Mound Rd 11 to 13 Mile	20136						$1,491	$9,037	
Atherton Road	16461			$709	$2,762	$5	-$34		
M-59 Lakena to Tipsico Lake	14579		$3,456	($45)					
I-75 Projects	GL-02841 GL-02842				$1,069	$3,884	$61		
Iron Belle Trail/ Gale Rd.	11001	$3,253							
13 Mile Road and Inkster	10010		$3,238						
I-94 BR Mich Ave	16055			$3,015					
Shiawassee & MLK	19927						$5,530	$707	$125
Lapeer Rd Burton	20993						$3,848	$153	$2
Passolt St	19624						$4,996	$79	
Atlas Iron Belle Trail	19919						$56	$7,910	$41
US 127 & 223	20824							$3,178	
Wayne Rd Bridge Replacement	20855						$303	$2,669	
9 Mile Road Eastpointe	19765 21012 22727					$4	$92	$10,623	$6,393
Other Projects	Various	$50,779	$59,514	$80,406	$53,524	$49,316	$81,375	$48,776	$37,048
Total Asset Relocation - Civic		**$58,236**	**$68,417**	**$90,700**	**$74,653**	**$56,401**	**$103,075**	**$83,518**	**$43,601**

Q. Please summarize the Company's projected investments in the Asset Relocation – Civic Improvement sub-program.

A. Asset Relocation – Civic Improvement sub-program expenditure projections are developed by engineering staff within the Gas Engineering Asset Planning Department and are summarized in Table 10 below. The scope and location of individual projects will be determined as requests are received. The projected test year amount of $82,162 reflects the Company's expectation that 10.11% of the 2025 calendar year capital investments and 89.88% of the 2026 calendar year capital investments will occur during the November 2025 to October 2026 time period.

Table 10: Asset Relocation – Civic Improvement Projections (in Thousands of Dollars)

Description	Actual 2023	Projected Calendar Year 2024	Projected Calendar Year 2025	Projected Calendar Year 2026	Projected Test Year
Total Asset Relocation – Civic Improvement (Thousands of Dollars)	**$83,518**	**$64,148**	**$70,770**	**$83,444**	
Test Year Dollar Detail:					
Calendar Year amounts included in the Projected Test Year (in Thousands)			**$7,158 (November through December)**	**$75,003 (January through October)**	**$82,162**

The calendar year 2026 projection of $83.444 million is a decrease of $0.074 million, or approximately 0.1% less, compared to the 2023 actual capital expenditures. Table 11 indicates the Company expects to install 166,365 feet of distribution main during 2026, which is an approximately 8.6% decrease in workload compared to 2023. Therefore, the difference between the calendar year 2026 capital investment and the 2023 historical actual capital investment is due to decreases in projected

work offset by increases in the average cost per mile installed of approximately 3% annually.

The calendar year 2025 projection of $70.770 million is a decrease of $12.748 million, or approximately 15.3% less, compared to 2023. Table 11 indicates that the Company expects to install 145,330 feet of distribution main during 2025, which is an approximately 20% decrease in workload compared to 2023. The difference between the calendar year 2025 capital investment and the 2023 capital investment, therefore, is due to decreases in projected work offset by increases in the average cost per mile installed of approximately 3% annually.

The calendar year 2024 projection of $64.148 million is a decrease of $19.370 million, or approximately 23.2% from 2023. Table 11 indicates that the Company expects to install 126,637 feet of distribution main during 2024, which is an approximately 30.4% decrease in workload. Therefore, the difference between the calendar year 2024 capital investment and the 2023 capital investment is due to decreases in projected work, offset by somewhat higher unit costs. In Table 9, I have identified actual capital expenditures through September 2024 of $43.601 million.

Q. Please summarize the work that the Company expects to complete during the 2024 through 2026 calendar years within the Asset Relocation – Civic Improvement sub-program.

A. Projected work for the Asset Relocation – Civic Improvement sub-program is detailed in Table 11 below. Specific projects that the Company has included in its 2023 actual and future year projections include the Mound Road reconstruction project, the Atlas Iron Belle Trail project, the 9 Mile Road Eastpoint project, and the Romeo Plank project.

Table 11: Asset Relocation – Civic Improvement Projection Details

	Actual 2023	2024 (Projected)	2025 (Projected)	2026 (Projected)
Projects	122	171	176	181
Feet of Distribution Main to be Installed	181,953	126,637	145,330	166,365
Asset Relocation Services to be Replaced	1,228	1,640	1,689	1,740

Q. What benefits are realized from the Company's investments in the Asset Relocation – Civic Improvement sub-program?

A. There are significant benefits realized because of capital investments in this program from an asset integrity and public safety perspective. Replacing vintage gas mains and services in the vicinity of heavy construction equipment reduces the likelihood of a leak either during or after construction that could result from the ground impact of that construction. This enhances the safety of those working on public infrastructure projects near these facilities, as well as any members of the general public that utilize the associated infrastructure. The coordination between the Company and the municipalities allows for the Company to have an increased awareness and better communication with the excavators on the project to prevent damages to the Company's gas system. Additionally, the relocation of mains and services can enable the future maintenance of main and service lines while minimizing disturbances to completed roadway improvements.

Q. How does the Company coordinate with road right-of-way owner agencies when it comes to public infrastructure improvement projects?

A. The Company is a strong proponent of coordinating infrastructure projects among utilities and road right-of-way owner agencies. Many of these public infrastructure projects affect

the Company's gas distribution facilities. In support of the Company's continual effort to promote coordination and efficient civic improvement projects, the Company also continues to be involved in the Michigan Infrastructure Council. The Company has engineering staff representatives that serve on subcommittees and contribute to periodic council meetings. Additionally, the Company encourages engineering staff to attend the Asset Management training sponsored by the Michigan Infrastructure Council.

The Company's Gas Engineering Asset Planning Department works with state and local government agencies to replace vintage gas facilities when appropriate for safety and reliability, and to attempt to save newer gas main and service materials from having to be replaced to minimize expense to the Company. Cities may have large programs to replace sewer systems or water main replacements, requiring major road construction and deep sewer or water installation. The Company will coordinate timing with the city to replace vintage mains and services that may leak from such type of construction. Coordinating project timelines with municipalities to align construction schedules also allows the Company to reduce its costs for hard and soft surface restoration once the gas system work is complete.

Additionally, there are many projects where the Company has plastic or coated and wrapped steel facilities, primarily gas mains, near the construction activities and will negotiate with the municipality or their engineering firm to get designs changed to protect the Company's gas facilities and prevent relocation. The Engineering Asset Planning team reviews municipal project plans and tries to negotiate municipal design changes to eliminate potential direct conflicts with Company facilities. These negotiations reduce

overall project scope and, therefore, reduce the costs to both the taxpayer and the Company's customers.

Q. Please summarize the Company's projections for the Asset Relocation – Civic Improvement sub-program.

A. As shown on Exhibit A-102 (LDW-3), line 1, the capital expenditures for the Asset Relocation – Civic Improvement Program were $83,518,139 in 2023, and are projected to be:

- $64,148,130 for the calendar year 2024;
- $63,611,817 for the ten months ending October 31, 2025; and
- $82,161,630 for the test year ending October 31, 2026.

These projections are based upon recent history, projections of increased federal and state funding for infrastructure improvements, and knowledge of specific projects planned for the next several years. The Company's projected capital expenditure amounts are required to meet the projected level of asset relocations associated with local and state government projects.

Q. Please further describe the expenditures associated with the Asset Relocation – Reimbursable Program.

A. The Asset Relocation – Reimbursable Program accounts for customer requested capital replacements of mains, services, and meter stands. These replacements are requested for multiple reasons, including when the customer desires to add sufficient gas equipment such that it requires a Company facility upgrade, has asked for relocation of a gas main or replacement of a gas service to accommodate a customer need, or has created an unsafe situation requiring Company facility replacement. Customers requesting or requiring these upgrades are responsible for the cost of the upgrade. When a customer is adding gas load

that will provide the Company more revenue, the Company applies the appropriate revenue credits as outlined in Tariff Rule C8 to help offset the customer's costs.

Q. What has been the Company's historical experience with the Asset Relocation – Reimbursable Program?

A. The Asset Relocation - Reimbursable Program investments have totaled $59.6 million for approximately 25,500 orders from 2019 through 2023, for a historical five-year average capital investment of approximately $11.9 million annually. During 2024, the Company invested approximately $19.0 million for more than 6,340 orders during the first nine months of the year and is projecting a total 2024 investment of $22.7 million because of increasing requests for relocation work being experienced by the Company during 2024. The $22.7 million projected for 2024 exceeds the $11.9 million of annual average investment experienced by the Company during 2019 through 2023. The increase of capital expenditures in 2024 is primarily related to a large project enabling the conversion of an existing vehicle assembly plant to shift production to electric vehicles, as well as increasing expenditures related to customer requests for meter stand replacements.

Table 12: Asset Relocation – Reimbursable sub-program Details (in Thousands of Dollars)

	2019	2020	2021	2022	2023	2024 (Jan - Sep)
Customer Requested Relocations	$9,338	$7,260	$5,888	$11,526	$12,956	$9,969
Damage Replacements	$1,570	$1,685	$1,473	$1,898	$1,100	$933
Large Customer Requested Relocation Projects	$4,755	$11			$107	$8,119
Other		$364	-$386	$4	$5	
Total Asset Relocation – Reimbursable	**$15,663**	**$9,320**	**$6,975**	**$13,429**	**$14,167**	**$19,020**

The 2023 actual costs and future period projections for this sub-program are reflected on Exhibit A-102 (LDW-3), line 2, and summarized as part of the Asset Relocation Program in Table 7 above. The capital expenditures for this sub-program were $14,167,169 in 2023 and were $738,603 higher than 2022 capital expenditures for this sub-program.

Q. Why are the 2023 actual amounts for the Asset Relocation – Reimbursable sub-program higher than the 2022 actual amounts?

A. The 2023 actual amount is higher than 2022 due to the following reasons:

- Customer Requested Relocation work required $1.429 million more investment due to increased costs associated with customer requests for meter stand work in 2023; and
- Damage Replacement work required $0.798 million less investment due to lower main replacement work order costs in 2023.

Q. Please describe how the forecasts for the Asset Relocation – Reimbursable sub-program were developed.

A. The Company's Customer Energy Management Department manages the Asset Relocation – Reimbursable sub-program and provides the forecasts for future year capital investments. The test year forecast of $16,647,126 includes $2,830,429 for November and December 2025 and $13,816,697 for January through October 2026. 81.2% of the 2026 annual forecast of $17,015,323 and 18.8% of the 2025 annual forecast of $15,056,675 are expected to occur in the test year based on historical timing of expenditures within this sub-program.

The 2026 calendar year forecast of $17,015,323 includes projected customer requested relocation investments of $15,474,782 and investments to correct damages of

$1,540,540. The increase in 2026 compared to the 2023 calendar year actual amount anticipates cost escalation and increasing requests for customer requested relocation work.

The 2025 calendar year forecast of $15,056,675 includes projected customer requested relocation investments of $13,594,649 and investments to correct damages of $1,462,026. The 2025 forecast anticipates cost escalation and increasing requests for customer requested relocation work from the 2023 actual amount.

The 2024 calendar year forecast of $22,690,010 includes actual investments for the first eight months of 2024 in the amount of $17,220,105 and projected investments for the last four months of 2024 in the amount of $5,469,905. The 2024 calendar year forecast is $8,522,841 more than the 2023 historical year amount. As noted previously, this increase is primarily related to customer requested relocation work at a large vehicle assembly facility as well as increasing customer requests for meter stand replacements.

Q. Please summarize the Company's projections for the Asset Relocation – Reimbursable sub-program.

A. As shown on Exhibit A-102 (LDW-3), line 2, the capital expenditures for the Asset Relocation – Reimbursable sub-program were $14,167,169 in 2023, and are projected to be:

- $22,690,010 for the calendar year 2024;
- $12,226,246 for the ten months ending October 31, 2025; and
- $16,647,126 for the test year ending October 31, 2026.

The Asset Relocation – Reimbursable sub-program projections are based upon the Company's recent experience with this sub-program. The Company's projected capital expenditure amounts are required to complete work associated with customer requested asset relocations and to resolve gas facility damages.

C. Regulatory Compliance

Q. Please describe the capital expenditures relating to the Regulatory Compliance Program shown on Exhibit A-12 (LDW-1), Schedule B-5.9, line 3.

A. The Regulatory Compliance Program includes projects that are required to comply with federal and state pipeline safety regulations and mandates. For gas distribution, components of this program are the Regulatory Base Distribution projects, the Meters sub-program, MAOP Distribution projects, and Cathodic Protection Distribution projects. The capital expenditures for this program were $34,487,525 in 2023, and are projected to be $45,216,771; $91,703,502; and $150,311,390 for the years 2024; the ten months ending October 31, 2025; and the test year ending October 31, 2026, as set forth on this exhibit on line 3, column (b); line 3, column (c); line 3, column (d); and line 3, column (f), respectively, of Exhibit A-12 (LDW-1), Schedule B-5.9. A further breakdown of the Regulatory Compliance Program expenditures is shown on Exhibit A-103 (LDW-4). The Regulatory Compliance expenditures are also shown in Table 13 below.

Table 13: Regulatory Compliance Program Capital Expenditures (in thousands of dollars)

Program Description	Historical 12 Mos Ended 12/31/2023	12 Mos Ending 12/31/2024	10 Mos Ending 10/31/2025	22 Mos Ending 10/31/2025	Projected Test Year 12 Mos Ending 10/31/2026
Regulatory Base - Distribution	$39	$0	$0	$0	$0
Meters	$20,450	$24,909	$23,457	$48,366	$24,700
MAOP Distribution	$1,607	$9,295	$59,964	$69,259	$115,812
Cathodic - Distribution	$12,392	$11,013	$8,282	$19,296	$9,800
Total Regulatory Compliance	**$34,488**	**$45,217**	**$91,704**	**$136,920**	**$150,311**

Q. Please describe the Regulatory Base Distribution sub-program.

A. This sub-program includes the capital construction projects that were required to meet regulatory commitments. This five-year program began in 2017 with an initial plan for 17 projects. When the Company committed to this program, it also committed to continue to monitor the Supervisory Control and Data Acquisition ("SCADA") system for station pressures that exceed 18" water column of pressure on each station outlet and address those as well. Through that continued observation, one of the original projects, High Street in Charlotte, was cancelled after further system planning analysis allowed the Company to lower the station pressure without any replacement. Another project, First Street in Jackson, was eliminated as the Company was able to coordinate the necessary system configuration changes with an Asset Relocation – Civic Improvement project for the City of Jackson in 2018. One project, Ada Street in Owosso, was added due to observed station pressures, bringing the total back to 17 projects in the program. The Chipman Street project in Owosso was split into two phases to allow it to be constructed over two years; a railroad crossing was completed in 2018 and the remainder of the project was completed in 2019.

These projects replaced sections of the standard pressure system with medium pressure plastic, which removed load from the standard pressure system. Standard pressure, sometimes called utilization pressure, is a low-pressure distribution system typically operating at 14" water column (~0.5 psig) or less where there may or may not be regulating equipment at the customer's meter, meaning the pressure on the system is the pressure that is provided to the customer. Medium pressure systems operate between 1 psig and 60 psig, meaning that each customer has a regulator installed at their meter to reduce the pressure prior to customer's end-use equipment. The scope of work for a typical project

involved replacing all vintage mains and services along with any other facilities not rated for the medium pressure system. Any existing main and service facilities rated to operate at medium pressure, but still operating at standard pressure, would be converted to medium pressure without replacement. Customers on both the replaced or upgraded sections of the system were provided with an appropriate meter and regulator to reduce the pressure before it enters the customer's building. Together, these changes to the system allow the Company to convert sections of the standard pressure system to medium pressure while reducing the operating pressures of the remaining standard pressure systems from 18" water column to 14" water column or less. These changes were agreed to by the Company and the MPSC Safety Staff in 2017. The Company completed this five-year program in 2022, as shown in Table 14 below:

Table 14: Regulatory Base Distribution sub-program
Compliance Project List with Status

Project Number	Headquarters	Project Name	Construction Year
11804	Jackson	Michigan	2018 – Complete
11693	Flint	South Flint SP	2018 – Complete
11979	Flint	Downtown SP	2018 – Complete
11747	Jackson	Ganson	2018 – Complete
12065	Bay City	Bay City East SP, Lincoln St.	2018 – Complete
11908	Owosso	Chipman	2018 – Complete
16175	Owosso	Chipman - Ph II (a.k.a. Cedar St.)	2019 - Complete
11716	Jackson	Seymour	2020 – Complete
11690	Flint	West Flint SP	2019 – Complete
11689	Flint	East Flint SP	2019 – Complete
14024	Jackson	Foote	2020 – Complete
11807	Jackson	Morrell	2019 – Complete
14016	Jackson	First St SP	2019 – Cancelled
11719	Bay City	Bay City West SP Walnut Street	2020 – Complete
12057	Bay City	Bay City East SP, Water Street	2021 - Complete

11720	Bay City	Bay City West SP Vermont Street	2021 - Complete
11717	Saginaw	Saginaw East SP	2022 – Complete
16132	Owosso	Ada St	2021 – Complete
12085	Lansing	High St – Charlotte	Cancelled

While this program reduces the operating pressure on the standard pressure system, there are additional benefits from this work. The projects constructed within this sub-program replaced approximately 10 miles of cast iron and other vintage mains and eliminated more than 200 vintage services. Existing plastic main in the standard pressure system was converted or uprated to medium pressure wherever practical, reducing the cost of replacement for these segments, while still transitioning them from the standard pressure system.

The Regulatory Base Distribution compliance sub-program is complete. The above details are included in my testimony to describe capital investments made during the historical year of 2022. The 2022 expenditures detailed on Exhibit A-103 (LDW-4), line 1, include actual capital investments made to complete the Company's standard pressure system upgrade commitment.

Q. Please describe the Meters sub-program within the Regulatory Compliance Program and the projections in this filing.

A. The meters purchased in the Regulatory Compliance Program are used in connecting New Business Program services, the Routine Meter Exchange Program, the Vintage Service Replacement Program, and for normal replacement of obsolete or broken meters. The Routine Meter Exchange Program involves replacing a portion of existing meters that measure customer consumption with a new or refurbished meter, then testing the old meter for compliance with MPSC billing accuracy standards. The Meters Program also includes

equipment purchased for customer requested work such as new service or meter requests, meter exchanges, and sets at existing premises where the meter had been previously removed. The meters being purchased are rotary meters and temperature compensating meters.

The Company purchases new gas meters on a periodic basis to ensure it has an adequate supply to meet customer and regulatory commitments. The Company establishes an annual meter purchase plan for each year in June of the preceding year. That purchase plan provides for meter quantities and types, broken into periodic releases from meter manufacturers throughout the year to meet all business requirements. Those requirements include new business sets, service upgrades, for-cause exchanges (damage, leak, obsolescence, etc.), project work such as EIRP and Vintage Service Replacements ("VSRs"), and regulatory testing requirements. Factors considered when establishing the annual plan include examination of current levels of inventory by meter type, assumptions of new business services expected in the coming year, historical for-cause exchange data, project work projections, historical trends for meter retirements, and regulatory program (i.e., the Routine Meter Exchange Program) projections. The meters are purchased according to that annual plan. The plan calls for receiving shipments of meters at different points throughout the year, so the Company can adjust the orders as material usage variations are observed. The projected test year dollar value includes 11.95% of the 2025 calendar year projection and 88.05% of the 2026 calendar year projection based on historical timing of meter purchase investments. The actual and projected total number of meters purchased for the Meters Program for each period in this filing are shown in Table 15 below:

Table 15: Actual and Projected Meters Program Purchases by Year

	2023 Actual	2024 Projection	2025 Projection	2026 Projection	Projected Test Year
Meter Units	35,200	43,107	47,546	46,394	46,574
Unit Cost	581	578	560	527	530
Total Meter Cost	**$20,450,366**	**$24,909,000**	**$26,641,190**	**$24,436,055**	**$24,699,612**

Q. What have the historical purchases and unit costs been for the Meters sub-program?

A. Historical purchases and unit costs are presented in the table below:

Table 16: Historical Actual Meters Purchased by Year

	2019 Actual	2020 Actual	2021 Actual	2022 Actual	2023 Actual
Meter Units	67,023	58,997	49,759	21,152	35,200
Unit Cost	435	419	503	546	581
Total Meter Cost	**$29,132,703**	**$24,742,799**	**$25,022,976**	**$11,558,636**	**$20,450,366**
Correctors	1,135	1,460	3,832		
Unit Cost	1,316	1,383	1,331		
Total Corrector Cost	**$1,493,119**	**$2,018,812**	**$5,100,820**		
Comm Modules	3,762	200	100		
Unit Cost	227	131	207		
Total Comm Module Cost	**$854,519**	**$26,166**	**$20,667**		
Total sub-program	**$31,480,341**	**$26,787,777**	**$30,144,463**	**$11,558,636**	**$20,450,366**

Q. What changes have impacted the costs of the Meters sub-program?

A. The costs in the Meters sub-program have been impacted by four significant changes in the recent past, all of which have affected unit cost for the meters purchased.

First, with the conclusion of the Advanced Meter Infrastructure ("AMI") and Automated Meter Reading ("AMR") programs in 2019, all meters are purchased with a gas communication module ("GCM") installed on the meter by the meter manufacturers. While the AMI and AMR programs were being implemented, the initial purchases of GCM devices were within the scope of those programs. With the initial installation of AMI and

AMR now complete, the cost of module purchases are included as part of the Meters Program. GCMs are meter manufacturer and meter-type specific. When meters are returned from the field, if the meter is scrapped or retired, the GCM is either scrapped or retired or, in the case of meters that will be returned to service, some GCM units are recycled to be used as replacements for defective or damaged GCMs or to mitigate any supply chain disruptions on the part of the GCM manufacturer that would cause delays in new meter shipments from the meter manufacturers. The Company has utilized recycled GCMs on new meters when the GCM supplier was unable to deliver GCMs to the meter manufacturer for installation before shipping new meters to the Company. The recycling of GCM units limits the purchase of new stand-alone GCMs primarily to the meter units that come with the GCM already installed.

Second, in late 2020, the sole-source provider of regulated meters (meters with a built-in regulator) announced the decision to discontinue production of diaphragm gas meters in mid-2021. From 2021 forward, the primary meter purchased will be the temperature compensating meter. The temperature compensating meter requires a separate regulator to be installed as part of the meter stand equipment. Purchasing meters without a built-in regulator will lower the unit cost of meters purchased within this program. The cost of the in-stand regulator is not included in this program but is included in work orders as part of other O&M expense and capital expenditure programs.

Third, historically, gas meter volume and temperature correctors and GCMs purchased as stand-alone units were purchased in this sub-program. Those stand-alone units are now included in the Meter Technology and Management Systems Support Program, which is sponsored by Company witness James P. Pnacek. The removal of these

future purchases is reflected in Table 15, above. All new meter purchases include the meter, the GCM, and where required, the temperature and volume correctors as a single unit.

The fourth and final item affecting expenditures in the Meters Program is testing equipment. In addition to meter purchases, this program contains costs for the testing equipment at the Company's Meter Technology Center. In 2020, the Company had planned to procure new leak test equipment for the regulated meters. With the end-of-life decision for the regulated meters, and the shift to the temperature compensating meters, the decision was made to shift the purchase of leak test equipment to temperature compensating meter leak testers and the procurement of that equipment was completed in 2022. In 2022, the Company procured new commercial and industrial test equipment and plans to acquire regulator test equipment over the next few years. Additionally, the 2022 expenditures in this sub-program include three new leak testers to support testing of unregulated meters. Meter test stations are also periodically replaced as needed within the expenditures for this sub-program. In 2025, the Company will be replacing regulator test equipment and temperature and pressure instrument test equipment.

Q. Please describe the MAOP Distribution sub-program within the Regulatory Compliance Program and the projections included in this filing.

A. The MAOP Distribution sub-program includes expenditures for projects on the gas distribution system where reconfirmation of the established MAOP is required due to new gas code language included in Pipeline and Hazardous Materials Safety Administration's

("PHMSA") regulation 49 CFR 192.624.[22] The PHMSA code states that pipeline segments that operate above 20% of the specified material yield strength (or "SMYS") are classified by PHMSA as transmission pipelines for the purpose of compliance with safety standards including MAOP. This regulation requires the Company to have a plan to reconfirm MAOP and remediate line segments for which the Company's pressure test records do not meet PHMSA's expectations for traceable, verifiable, and complete documentation. The compliance milestones set forth by the regulation are to complete all actions required by 49 CFR 192.624 on 50% of the pipeline mileage subject to MAOP reconfirmation requirements by July 3, 2028, and complete all actions required by 49 CFR 192.624 on 100% of the pipeline mileage subject to MAOP reconfirmation requirements by July 2, 2035. In some specific cases, replacement of gas distribution assets is determined to be the most effective way of reconfirming the MAOP. The Company has identified thirty-one projects to date, representing approximately 40.25 miles of distribution main installation, and these projects are listed in Appendix F of the NGDP exhibit sponsored by Company witness Dreisig. Projections for each project included in this sub-program are developed by the Company's Engineering Asset Planning Department. Fourteen projects will have capital expenditures during 2023 through 2026 as shown in Table 17 below:

[22] 49 CFR 192.624 is titled "Maximum allowable operating pressure reconfirmation: Onshore steel transmission pipelines"; Michigan Administrative Code R 460.20606 adopts 49 CFR Part 192 by reference.

Table 17: MAOP Distribution sub-program Compliance Project List

Project Number	Project Name	2023 Projected ($000)	2024 Projected ($000)	2025 Projected ($000)	2026 Projected ($000)	Construction Completion Year
21948 & 21250	Line 1080, West from Kalamazoo	363	3,829	30,041	465	2025
22861 & 22862	Line 1022, Airport CG to State Rd & State Rd to W Grand River	41	87		39,781	2026
22781	Line 1041, Lapeer Rd	244	306			2028
22393	Line 1002c	934	688	15,428	40,063	2029
21676	Line 1093, Shattuck Rd				20,901	2026
21788	Line 1009, Huron Park to I-94	24	3,183			2024
22511	Line 1022f, Vermontville			373		2025
22157 & 22494	Line 1009/1009c I-94 to Little Mack, 10 Mile to 11 Mile; 9 Mile to 10 Mile			19,935	9,643	2025 2026
22702	Line 1006, Groebel Dr to Mound Rd		161		6,215	2026
22150	Line 1002f, Macomb ITC Corridor		16	2,980		2025
22409	Line 1020, Greenfield Rd		258			2024
21674 & 21675	Line 1087b, East and West Segments		505	10,173		2025
TBD	Line 1026f, Mt Hope				10,829	2026
TBD	Line 1026i, MSU PP					2027
22532	Line 1090n, Davis St		218	109		2025
	Program Adjustment		44	-9,923		
Total 2023-2026 Projection		**$1,607**	**$9,295**	**$69,117**	**$127,897**	

Q. Please explain why the replacement of gas distribution assets would be determined to be the most effective way of reconfirming the MAOP of a line segment.

A. For the projects requiring reconfirmation, engineering staff within the Company have performed an evaluation to determine the best course of action to comply with 49 CFR 192.624. The Company must utilize one of six methods identified in 49 CFR 192.624 to reconfirm its MAOP. The Company selected reconfirmation Method 4 - Pipeline Replacement as the preferred approach for remediation after evaluating all the methods offered in 49 CFR 192.624 for each gap segment. In general, the Company arrived at this conclusion because the other reconfirmation methods are not practical or feasible due to existing operational constraints and risks on the Company's distribution system. One benefit of pipeline replacement is that the replacement pipeline would be designed, constructed, and pressure tested according to current standards to establish MAOP. Pressure testing would take place on the new pipe prior to being placed into service. As a result, operational risks and constraints associated with re-testing pipe that is already in-service would be avoided.

The other identified methods were not selected for several reasons. For example, reconfirmation Method 1 – Pressure Testing, is an infeasible option in cases where operational constraints and risks surrounding gas quality and gas deliverability requirements exist. This is infeasible because the natural gas distribution system is not generally designed for the removal of water from the pipeline after completion of pressure testing and material verification procedures required to comply with the traceable, verifiable, and complete documentation standard; this means many distribution line segments may only be resolved through pipeline replacement. Additionally,

reconfirmation Methods 2 and 5, which relate to pressure reductions, are generally not practical solutions in most instances because the Company cannot meet gas deliverability[23] requirements at the reduced MAOP to comply with the regulations.

All three of these methods are examples of situations that create an unacceptable risk. For instance, if pressure testing failed, the line would have to be replaced anyway and the potential for unplanned outages during such an event, particularly if it created the need for replacement before the winter heating season, would create a risk that the Company would not be able to provide gas to customers when needed. Similarly, the line segments identified as requiring MAOP confirmation exist on critical high-pressure systems, some being highly interconnected; this is especially true for distribution lines in the southeast Michigan portion of the Company's service area. In each instance, a pressure reduction would have to be taken along the full length of the line – or multiple adjacent lines in the case of interconnected systems – which would reduce deliverability in downstream line segments.

Q. Please explain the Line 1080 project.

A. In addition to the work being done by the Company to evaluate compliance with MAOP standards described above, the Company has received notice from Staff that Line 1080, which serves customers to the west of Kalamazoo, needs to be operated at a lower pressure to comply with 49 CFR 192.619.[24] The Company, however, cannot meet current deliverability requirements at this new specified operating pressure. Options to augment

[23] Definition of gas "deliverability": the ability of a natural gas service provider to meet its customers' needs based on seasonal requirements and operating conditions.

[24] 49 CFR 192.619 is titled "Maximum allowable operating pressure: Steel or plastic pipelines"

this line segment have been reviewed by the Company, and pipeline modifications are planned for construction during 2025.

The Line 1080 project is unique among the MAOP projects planned for during the timeframe of this case. The MAOP compliance remedy for this pipeline involves reducing the operating pressure on the line from its current operating pressure to the pressure documented in the records used to establish MAOP via 49 CFR 192.619(c). The Line 1080 segment being addressed does not require reconfirmation of MAOP per 49 CFR 192.624, as it does not meet the definition of a covered segment.[25] The Company has adequate documentation to operate the line at the lower pressure per 49 CFR 192.619(c) and needs to augment the system to enable the operation of this line at the lower pressure, so customers are not at risk of losing service. The Company plans to keep the existing pipeline in service and augment the distribution system by constructing a 6.7 mile parallel main.

Line 1080 is a single feed system that serves approximately 19,000 customers. It is comprised primarily of 8" diameter high-pressure steel which operates at >20% Specified Minimum Yield Strength. This line was primarily installed in the 1950s. It runs west out of the M Avenue City Gate, feeding the local communities west of the City of Kalamazoo. The Line 1080 project completed survey and field investigations during 2022. Project planning and city gate facility upgrades were completed in 2023. Project milestones during 2024 include acquisition of real estate, completion of construction plans, delivery of long lead time materials, and issuing requests for construction bids. Construction contracts are expected to be executed early in 2025 so that actual construction

[25] Provisions that grandfather the documentation requirements for Line 1080, and the fact that pressure test records are not missing for this segment explain why Line 1080 is not a "covered segment".

will take place during 2025. The Company plans to improve the resilience of the system in the area served by Line 1080, which has limited sources of supply, by constructing a 6.7 mile 12" diameter parallel main to the existing main. Other alternatives considered by the Company (developing loops of main in that area to create connections with additional city gates to provide additional supply locations) to improve resilience were excessive in terms of the cost to construct versus the overall resilience risk reduction.

Q. Please explain the Line 1009 Huron Park to I-94 project.

A. The Line 1009 Huron Park to I-94 project was completed during 2024. This replacement ensures compliance with 49 CFR 192.624 for this half mile segment of 12 inch high pressure steel main. This project is the first phase of four MAOP replacement projects associated with the Line 1009/1009c line segment. The Line 1009 Huron Park to I-94 line segment was originally installed in 1969 and was approximately 55 years old at the time of replacement. It is in Macomb County. The Company determined that pressure testing was not practical and pressure reduction was not feasible for this line segment. To verify the material properties of this segment, the Company would have needed to remove cutout sections of the line. To minimize the impact of pressure testing, pressure reduction, and material testing, the Company believes that it was reasonable and in the best interest of safety, deliverability, and compliance to utilize the replacement option for Line 1009 Huron Park to I-94.

Q. Please explain the Line 1009/1009c I-94 to Little Mack/10 Mile to 11 Mile project.

A. The Line 1009/1009c I-94 to Little Mack/10 Mile to 11 Mile project scope includes 1.53 miles of 12" diameter main installation to replace the existing 10" diameter main. It is the second phase of four phases of MAOP replacement for the Line 1009/1009c line

segment. The Line 1009/1009c I-94 to Little Mack, 10 Mile to 11 Mile project line segment was installed in 1969 and is approximately 55 years old. It is in Macomb County. The Company has determined that pressure testing is not practical, and pressure reduction is not feasible for this line segment. To verify the material properties of this segment, the Company would need to remove cutout sections of the line. To minimize the impact of pressure testing, pressure reduction, and material testing; it is in the best interest of safety, deliverability, and compliance to utilize the replacement option for Line 1009/1009c I-94 to Little Mack, 10 Mile to 11 Mile. This second phase of the Line 1009/1009c replacement is currently in the design phase of project development and will be constructed during 2025.

Q. Please explain the Line 1022f Vermontville project.

A. The Line 1022f Vermontville project scope includes 0.038 mile of 8" diameter main installation to replace a similar sized existing main segment. The existing Line 1022f Vermontville line segment was installed in 1982 and is approximately 42 years old. It is in Eaton County. The Company has determined that pressure testing is not practical, and pressure reduction is not feasible for this line segment. To verify the material properties of this segment, the Company would need to remove cutout sections of the line. To minimize the impact of pressure testing, pressure reduction, and material testing it is in the best interest of safety, deliverability, and compliance to utilize the replacement option for the Line 1022f Vermontville project. The Line 1022f Vermontville project is currently in the planning and design phase of project development and will be constructed during 2025.

Q. Please explain the Line 1002f Macomb ITC Corridor project.

A. The Line 1002f Macomb ITC Corridor project scope includes 0.07 mile of 26" diameter main installation to replace a similar sized existing main segment. The existing Line 1002f

Macomb ITC Corridor line segment was installed in 1971 and is approximately 53 years old. It is in Macomb County. The Company has determined that pressure testing is not practical and pressure reduction is not feasible for this line segment. To verify the material properties of this segment, the Company would need to remove cutout sections of the line. To minimize the impact of pressure testing, pressure reduction, and material testing it is in the best interest of safety, deliverability, and compliance to utilize the replacement option for the Line 1002f Macomb ITC Corridor project. The Line 1002f Macomb ITC Corridor project is currently in the design phase of development and will be constructed during 2025.

Q. Please explain the Line 1020 Greenfield Road project.

A. The Line 1020 Greenfield Road project scope includes 0.038 mile of 12" diameter main installation to replace a similar sized existing main segment. The existing Line 1020 Greenfield Road line segment was installed in 2006 and is approximately 18 years old. It is in Oakland County. The Company has determined that pressure testing is not practical, and pressure reduction is not feasible for this line segment. To verify the material properties of this segment, the Company would need to remove cutout sections of the line for the purpose of destructive testing. To minimize the impact of pressure testing, pressure reduction, and material testing it is in the best interest of safety, deliverability, and compliance to utilize the replacement option for the Line 1020 project. This project is currently under construction during 2024.

Q. Please explain the Line 1087b East and West Segment projects.

A. The Line 1087b East and West Segments project scope includes 0.81 mile of 12" diameter main installation to replace an existing 8" diameter existing main segment. The majority of this line segment was installed during the 1970s and a small section was installed during

the 1990s. It is in Midland County. The Company has determined that pressure testing is not practical, and pressure reduction is not feasible for this line segment. To verify the material properties of this segment, the Company would need to remove cutout sections of the line for the purpose of destructive testing. To minimize the impact of pressure testing, pressure reduction, and material testing; it is in the best interest of safety, deliverability, and compliance to utilize the replacement option for the Line 1087b East and West Segments project. This replacement project will be constructed in two phases. Each phase is currently in the design phase of development and construction is planned to occur during 2025.

Q. Please explain the Line 1009/1009c Phase 3, 9 Mile to 10 Mile project.

A. The Line 1009/1009c Phase 3, 9 Mile to 10 Mile project scope includes 1.3 miles of 12" diameter main installation to replace a similar sized existing main segment. The existing Line 1009/1009c Phase 3, 9 Mile to 10 Mile line segment was installed in 1969 and is approximately 55 years old. It is in Macomb County. The Company has determined that pressure testing is not practical, and pressure reduction is not feasible for this line segment. To verify the material properties of this segment, the Company would need to remove cutout sections of the line for the purpose of destructive testing. To minimize the impact of pressure testing, pressure reduction, and material testing; it is in the best interest of safety, deliverability, and compliance to utilize the replacement option for the Line 1009/1009c Phase 3, 9 Mile to 10 Mile project. The Line 1009/1009c Phase 3, 9 Mile to 10 Mile project is currently in the planning phase of project development. Design work is planned for 2025, and construction is planned for 2026.

Q. Please explain the Line 1002c project.

A. The Line 1002c project scope includes 8.15 miles of 24" diameter main installation to replace a similar sized existing main segment. The existing Line 1002c line segment was primarily installed in 1959 and 1960 and is more than 60 years old. It is in Oakland County. The Company has determined that pressure testing is not practical due to the length of the line segment that needs to be reconfirmed and pressure reduction is not feasible given gas deliverability requirements on the high-pressure system. To verify the material properties of this segment, the Company would need to remove cutout sections of the line for the purpose of destructive testing. To minimize the impact of pressure testing, pressure reduction, and material testing; it is in the best interest of safety, deliverability, and compliance to utilize the replacement option for the Line 1009c project. The Line 1002c project is currently in the planning phase of project development. Design work will occur during 2025, and construction is planned to occur in phases starting in 2026 and ending in 2029.

Q. Please explain the Line 1022 Airport City Gate to State Rd and State Rd to W Grand River project.

A. The Line 1022 Airport City Gate to State Rd and State Rd to W Grand River project scope includes 3.5 miles of 16" diameter main installation to replace a similar sized existing main segment. The existing Line 1022 Airport City Gate to State Rd and State Rd to W Grand River was primarily installed in 1963 and is more than 60 years old. One additional segment was installed in 1980 and is more than 40 years old. It is in Clinton County. The Company has determined that pressure testing is not practical, and pressure reduction is not feasible for this segment. To verify the material properties of this segment, the

Company would need to remove cutout sections of the line for the purpose of destructive testing. To minimize the impact of pressure testing, pressure reduction, and material testing; it is in the best interest of safety, deliverability, and compliance to utilize the replacement option for the Line 1022 Airport City Gate to State Rd and State Rd to W Grand River project. The Line 1022 project is currently in the planning phase of project development, which will conclude during 2025. Design work will also be completed in 2025, with construction planned for 2026.

Q. Please explain the Line 1041 Lapeer Rd project.

A. The Line 1041 Lapeer Rd project scope includes 3.4 miles of 12" diameter main installation to replace a similar sized existing main segment. The existing Line 1041 Lapeer Rd was installed in 1967 and is approximately 57 years old. It is in Genesee County. The Company has determined that pressure testing is not practical, and pressure reduction is not feasible for this segment. To verify the material properties of this segment, the Company would need to remove cutout sections of the line for the purpose of destructive testing. To minimize the impact of pressure testing, pressure reduction, and material testing; it is in the best interest of safety, deliverability, and compliance to utilize the replacement option for the Line 1041 Lapeer Rd project. Planning work for the development of this project is planned for 2025, design is planned for 2026, and construction is planned for 2027.

Q. Please explain the Line 1093 Shattuck Rd project.

A. The Line 1093 Shattuck Rd project scope includes 1.76 miles of 12" diameter main installation to replace a similar sized existing main segment. The existing Line 1093 Shattuck Rd was installed in 1967 and is approximately 57 years old. It is in Saginaw County. The Company has determined that pressure testing is not practical, and pressure

reduction is not feasible for this segment. To verify the material properties of this segment, the Company would need to remove cutout sections of the line for the purpose of destructive testing. To minimize the impact of pressure testing, pressure reduction, and material testing; it is in the best interest of safety, deliverability, and compliance to utilize the replacement option for the Line 1093 Shattuck Rd project. The Line 1093 Shattuck Rd project is currently in the planning phase of project development, with design work planned for 2025 and construction planned for 2026.

Q. Please explain the Line 1006 Groebel Dr to Mound Rd project.

A. The Line 1006 Groebel Dr to Mound Rd project scope includes 0.31 mile of 24" diameter main installation to replace a similar sized existing main segment. The existing Line 1006 Groebel Dr to Mound Rd was installed in 1959 and is approximately 65 years old. It is in Macomb County. The Company has determined that pressure testing is not practical, and pressure reduction is not feasible for this segment. To verify the material properties of this segment, the Company would need to remove cutout sections of the line for the purpose of destructive testing. To minimize the impact of pressure testing, pressure reduction, and material testing; it is in the best interest of safety, deliverability, and compliance to utilize the replacement option for the Line 1006 Groebel Dr to Mound Rd. The Line 1006 Groebel Dr to Mound Rd project is currently in the planning phase of development, with design work planned for 2025 and construction planned for 2026.

Q. Please explain the Line 1026f Mt Hope project.

A. The Line 1026f Mt Hope project scope includes 0.758 mile of 8" diameter main installation to replace a similar sized existing main segment. The existing Line 1026f Mt Hope was installed in 1998 and is approximately 26 years old. It is in Ingham County. The Company

has determined that pressure testing is not practical, and pressure reduction is not feasible for this segment. To verify the material properties of this segment, the Company would need to remove cutout sections of the line for the purpose of destructive testing. To minimize the impact of pressure testing, pressure reduction, and material testing; it is in the best interest of safety, deliverability, and compliance to utilize the replacement option for the Line 1026f Mt Hope project. The Line 1026f Mt Hope project is currently in the planning phase of project development, with design work scheduled for 2025 and construction planned for 2026.

Q. Please explain the Line 1026i MSU PP project.

A. The Line 1026i MSU PP project scope includes 0.133 mile of 8" diameter main installation to replace a similar sized existing main segment. The existing Line 1026i MSU PP segment was installed in 1970 and is approximately 54 years old. It is in Ingham County. The Company has determined that pressure testing is not practical and pressure reduction is not feasible for this segment. To verify the material properties of this segment, the Company would need to remove cutout sections of the line for the purpose of destructive testing. To minimize the impact of pressure testing, pressure reduction, and material testing; it is in the best interest of safety, deliverability, and compliance to utilize the replacement option for the Line 1026i MSU PP project. The Line 1026i MSU PP project will begin the planning phase of development in 2025, with design work planned for 2026 and construction planned for 2027.

Q. Please explain the Line 1090n Davis St project.

A. The Line 1090n Davis St project scope includes 0.012 mile of 8" diameter main installation to replace a similar sized existing main segment. The existing Line 1090n Davis St

segment was installed in 2002 and is approximately 22 years old. It is in Tuscola County. The Company has determined that pressure testing is not practical and pressure reduction is not feasible for this segment. To verify the material properties of this segment, the Company would need to remove cutout sections of the line for the purpose of destructive testing. To minimize the impact of pressure testing, pressure reduction, and material testing it is in the best interest of safety, deliverability, and compliance to utilize the replacement option for the Line 1090n Davis St project. The Line 1090n Davis St project construction was completed during 2024.

Q. Please describe the Cathodic Protection Distribution sub-program within the Regulatory Compliance Program and the associated projections included in this filing.

A. As shown on Exhibit A-103 (LDW-4), line 4, the capital expenditures for this sub-program were $12,391,559 in 2023, and are projected to be $11,013,242 in 2024; $8,232,359 for the ten months ending October 31, 2025; and $9,800,115 for the 12 months ending October 31, 2026, as set forth on this exhibit on line 4, column (b); line 4, column (c); line 4, column (d); and line 4, column (f), respectively. Table 13 above also shows the capital expenditures for the Cathodic Distribution sub-program.

The capital expenditures include a combination of impressed current installations (new and replacements), galvanic (sacrificial) anode installations, and the replacement of services or mains to clear shorted sectors. Exhibit A-103 (LDW-4), line 4, provides further details of the expenditures included in this program.

Q. Please describe the need for the Company to make capital investments in impressed current installations.

A. The impressed current installations include a combination of rectifier installations (new and replacements) and impressed current groundbed installations (new and replacements). The impressed current systems (rectified) consist of an external DC power source that supplies power to anode beds installed below grade. These impressed current systems include a combination of conventional groundbeds (surface beds), semi deep groundbeds (20 feet to 150 feet deep), and deep anode systems (greater than 225 feet in depth). The Company continues to install impressed current systems (rectified systems) and remote monitoring units ("RMUs"). The rectified systems allow the Company more control of system performance by having the ability to adjust the amount of current being applied to the system. The installation of RMUs allows the Company to monitor the output of rectifiers remotely.

Q. What is the status of the Company's installation of remote monitoring units?

A. The Company plans to complete the installation of 336 RMUs during the 2024 calendar year, in addition to the 559 that are already in service. The RMU installations are going to be complete during 2024.

Q. What are the benefits that will be realized as a result of the Company's installation of RMUs?

A. Statewide, distribution corrosion has a total of 896 rectifiers that must be read every two months, six times per calendar year. Historically these bi-monthly reads had to be read manually. The installation of RMUs reduces the number of required physical visits of each rectifier to one visit per year. This will help reduce the environmental impact of driving to

each of these rectifiers and will keep operating and maintenance costs down. Additionally, the RMU installations allow the Company to receive notifications when the rectifiers are not outputting correctly, diagnostic work can then be initiated quicker, which improves the integrity and reliability of the distribution system. RMU devices also allow for the Company to remotely interrupt rectifiers to perform cathodic surveys and testing.

Q. Please describe the need for the Company to make capital investments in galvanic anode installations.

A. Galvanic anode systems protect natural gas mains from corrosion using 17-pound and 20-pound magnesium anodes that are installed near a gas main. These anodes attract naturally occurring corrosion that would otherwise cause cracks, leaks, and other dangerous safety hazards in gas distribution mains. Replacement of existing magnesium anodes is necessary when annual surveys and associated diagnostics indicate the existing anodes have depleted. The installation of new galvanic anodes is necessary when the current output no longer provides an adequate level of cathodic protection to the pipeline.

Q. Please describe the need for the Company to make capital investments in services or mains within the Cathodic Protection Distribution program.

A. Annual surveys of services and mains are conducted to identify any segments that have experienced corrosion to the extent that replacement is required to maintain safety and reliability.

Q. Please describe the need for the Company to make capital investments in casing test points?

A. The cathodic protection system requires an adequate number of test points for cathodic protection application and monitoring. Casing test point reads are required to be read on

an annual basis to ensure casing and carrier pipe are not electrically continuous. Casings that have been identified in the Company's mapping systems and corrosion databases, which do not have an active test point, are being excavated, a test point is installed, and test points are read to ensure electrical discontinuity between casing and carrier pipe.

Q. What Federal and State regulatory standards make it necessary for the Company to invest in the Cathodic Protection Distribution sub-program?

A. The applicable Federal and State regulatory standards include Michigan Gas Safety Standards Section Three, Subpart I which is titled "Requirements for Corrosion Control". Within Subpart I, Section 192.463 is titled "External corrosion control: Cathodic protection". Similarly, Federal standards include Title 49 of the Code of Federal Regulations, subtitle B, chapter 1, subchapter D, part 192, subpart I, which is also titled "Requirements for Corrosion Control".

Q. What amount has the Company historically invested in the Cathodic Protection Distribution sub-program?

A. The Company invested $39.654 million in the Cathodic Protection Distribution sub-program during 2019-2023. The annual investment averaged $7.931 million per year over that time period. Annual amounts for each year were:

- 2019 historical actual: $5,039,720;
- 2020 historical actual: $6,663,545;
- 2021 historical actual: $6,976,687;
- 2022 historical actual: $8,582,806;
- 2023 historical actual: $12,391,559;
- 2024 projected: $11,013,242;

- 2025 projected: $9,535,994; and
- 2026 projected: $9,840,093.

Q. What portion of the historical and projected investments in the Cathodic Protection Distribution sub-program represent investments in RMU Installations?

A. The Company invested $2.494 million in the Cathodic Protection Distribution sub-program during 2019-2023 for RMU Installations. The annual investment averaged $0.499 million per year over that period. Annual amounts for each year are:

- 2019 historical actual: $608,746;
- 2020 historical actual: $532,356;
- 2021 historical actual: $720,208;
- 2022 historical actual: $632,899;
- 2023 historical actual: $0;
- 2024 projected: $791,603;
- 2025 projected: $102,500; and
- 2026 projected: $105,575.

Q. What portion of the historical and projected investments in the Cathodic Protection Distribution sub-program represent investments in Rectifier and Groundbed installations and replacements?

A. The Company invested $8.028 million in the Cathodic Protection Distribution sub-program during 2019 to 2023 for Rectifier and Groundbed installations and replacements. The annual investment averaged $1.606 million per year over that time period. Annual amounts for each year are:

- 2019 historical actual: $1,191,788;

- 2020 historical actual: $1,001,186;
- 2021 historical actual: $1,185,666;
- 2022 historical actual: $2,220,388;
- 2023 historical actual: $2,429,288;
- 2024 projected: $2,705,528;
- 2025 projected: $956,616; and
- 2026 projected: $980,710.

Q. What portion of the historical and projected investments in the Cathodic Protection Distribution sub-program represent investments in other capital repairs?

A. The Company invested $29.132 million in the Cathodic Protection Distribution sub-program during 2019 to 2023 for other capital repairs. The annual investment averaged $5.826 million per year over that time period. Annual amounts for each year are:

- 2019 historical actual: $3,239,186;
- 2020 historical actual: $5,130,002;
- 2021 historical actual: $5,070,813;
- 2022 historical actual: $5,729,519;
- 2023 historical actual: $9,962,271;
- 2024 projected: $7,516,111;
- 2025 projected: $8,476,878; and
- 2026 projected**:** $8,753,808.

Q. How were the projections for the Cathodic Protection Distribution sub-program developed?

A. Projections for the Cathodic Protection Distribution expenditures are provided by engineering staff within the Gas System Integrity Engineering Department. The test year value was determined using historical calendar month actual experience to include $1,253,635, or 13.15%, of the calendar year 2025 forecast and $8,546,481, or 86.85%, of the calendar year 2026 forecast. The test year total of $9,800,116 is 20.9% lower than the 2023 actual capital investment and is approximately 23.6% higher than the five-year average amount of $7,930,863. The projected increases reflect increasing materials and contractor costs that have been experienced during 2022 and 2023.

The calendar year 2026 forecast for the Cathodic Protection Distribution sub-program is $9,840,093. This forecast includes ~~$0~~ $105,575 for RMU installations, $980,710 for Rectifier and Groundbed installations and replacements, and $8,753,808 for other capital repairs. The 2026 calendar year forecast is 20.6% lower than the 2023 historical actual investment, and approximately 24.1% more than the 2019 to 2023 historical average. Increasing material and contractor costs are the primary reasons for projections being higher than the historical five-year average.

The calendar year 2025 forecast for the Cathodic Protection Distribution sub-program is $9,535,994. This forecast includes $102,5000 for RMU installations, $956,616 for Rectifier and Groundbed installations and replacements, and $8,476,878 for other capital repairs. The 2025 calendar year forecast is 23.0% lower than the 2023 historical actual investment, and approximately 20.2% lower than the 2019 to 2023

historical average. Increasing material and contractor costs are the primary reasons for projections being higher than the historical five-year average.

The calendar year 2024 forecast of $11,013,242 includes actual expenditures for the January through August period of $6,587,308 and projected expenditures for the September through December period of $4,425,935. The 2024 calendar year forecast is 11.1% than the 2023 historical actual expenditure.

D. Capacity/Deliverability

Q. Please describe the capital expenditures relating to the Distribution Capacity and Deliverability Program as shown on Exhibit A-12 (LDW-1), Schedule B-5.9, line 4.

A. As shown on Exhibit A-12 (LDW-1), Schedule B-5.9, the capital expenditures the Company experienced in 2023, and is projecting for the years 2024, the ten months ending October 31, 2025, and the test year ending October 31, 2026, are $4,445,928; $7,493,075; $7,019,380; and $5,354,075, as set forth on this exhibit on line 4, columns (b) through (f), respectively. The expenditures in the Capacity/Deliverability Program are also shown in Table 18 below:

Table 18: Capacity/Deliverability Capital Expenditures (in Thousands of Dollars)

Program Description	Historical 12 Mos Ended 12/31/2023	12 Mos Ending 12/31/2024	10 Mos Ending 10/31/2025	22 Mos Ending 10/31/2025	Projected Test Year 12 Mos Ending 10/31/2026
Augment	4,446	7,493	7,019	14,512	5,354
Total Capacity/ Deliverability	**4,446**	**7,493**	**7,019**	**14,512**	**5,354**

Exhibit A-104 (LDW-5) provides a detailed breakdown of these expenditures. These capital expenditures reflect needed increases in distribution pipeline capacity, which help ensure adequate pressures for deliverability throughout the system.

Q. Why are Capacity/Deliverability projects necessary?

A. Capacity requirements can change due to shifts in population into new locations, as has been recently experienced in the communities near Macomb, which the Company addressed by the installation of pipe near Huron Point and Selfridge Air Force Base. The Company also continued the augmentation of the medium pressure system in Caledonia in 2020. Further, capacity requirements can increase due to changes in system requirements, as the ways customers use gas change. With the price of the gas commodity remaining relatively low, requests for gas process load, including natural gas-fueled power generation, continue to increase. Substantial requests for additional load, shifts in population and usage, and general system growth cause new low points and bottlenecks to be identified on the gas distribution system. Investment in this program ensures that customers receive reliable gas service even on the coldest days.

Q. Can you describe the process of identifying Augment investments?

A. As described on page 96 of the SEA, the distribution system periodically requires augmentation to adjust for capacity requirements based on current and future gas needs. These projects are identified and prioritized based on gas load analysis software that evaluates system requirements by combining weather conditions (temperature) with known consumption data and system pressures. If the analysis reveals low pressures are expected, the Company will typically install a pressure recording chart to validate the modeled pressures over the next winter. Once validated, an augment project is initiated to reinforce

the system, bringing additional capacity or pressure from other parts of the system, to prevent outages or load restrictions to customers. In general, a smaller scope system augmentation project is not planned more than one heating season in advance as they are based upon the system load analysis and actual pressure observations mentioned above.

Q. Please summarize the Augment sub-program investments made by the Company over the past five historical years?

A. Over the time period of 2019 through 2023, the Company has invested over $28.3 million in distribution system Augment projects, as summarized in the following table:

Table 19: Historical Actual Augment Investments by Year

	2019 Actual	2020 Actual	2021 Actual	2022 Actual	2023 Actual	2024 Jan - Sep
Caledonia HP Phase 1	$13,613	$488				
Caledonia HP Phase 2	$10,319			-$512		
Caledonia HP Phase 3	$1,724,630	$35,961	-$153			
Gratiot Ave HP Repl			$2,803,277	$1,514,207		
Caledonia MP / Cherry Valley Ave		$1,778,302	$287,842	-$100		
Hickory Corners			$910,795	$455,855		
Shaffer Rd East of Alamando				$4,052,568	$18,338	0
Imlay City Rd & Lk Pleasant				$1,626,475	-$13,529	
W Sanilac Rd				$1,032,909		
Climax CG					$1,925,844	$45
Walled Lake – Welch & Oak					$1,723,201	-$22,405
Galesburg – Celery & River St.						$1,996,171
Other Projects	$1,811,393	$1,784,195	$2.501,265	$1,514,431	$792,074	$1,332,103
Total Augment	**$3,559,955**	**$3,598,945**	**$6,503,025**	**$10,195,833**	**$4,445,928**	**$3,305,914**

The average historical annual investment for 2019 through 2023 is approximately $5.7 million. The largest project for 2020 was the Caledonia MP Augment Project. This project was chosen to shift supply to the southern area. This was the lowest cost option to serve the area and reduce customer impact. The Gratiot Rd HP replacement was the largest

project for 2021. It involved replacement of undersized HP pipe with properly sized main allowing for the station to supply adequate amounts of gas to the Macomb area. The Shaffer Rd East Alamando project was the largest project for 2022. This project also involved the replacement of undersized HP pipe with properly sized main, which will increase the supply of gas to an area north of Midland. The Climax City Gate project is the largest augment project constructed during 2023. The construction of this project was necessary to increase the capacity of the system serving areas to the north of Climax extending to the Gun Lake area.

Q. Can you describe the Augment investments included in this filing?

A. There are several projects planned for 2024 through 2026 to reduce bottlenecks on the system. These are intended to provide capacity and resiliency outside the Galesburg City Gate (the Celery and River Street project high pressure main installation) and Coleman-Beaverton City Gate (the Shaffer Road and Beaverton projects high pressure main installation). These projects as well as several other smaller projects will require a projected total investment of $20.5 million over that time period.

Examples of augmentation projects currently planned for 2024 through 2026 include:

- Connecting the existing medium pressure distribution system to a new outlet at the Orion City Gate requires construction of approximately 1100 feet of six-inch medium pressure plastic main. The connection to the new outlet enhances capacity and resilience in an area where growth could create low pressure conditions. This project is planned for completion by November 2024.

- A project is planned to install approximately 1700 feet of four-inch plastic medium pressure main on Rives Junction Road and 1300 feet of two-inch medium pressure plastic main on Parnall Road in the Jackson area to construct a looped gas supply to reduce risks of low pressure as well as improve resilience on this main. The project is planned for construction during 2026.

- A project is planned to install approximately 1100 feet of six-inch plastic medium pressure main on Belsay Rd that connects with existing two-inch medium pressure main on Burton Estates Drive east of Flint. This project will

address low pressure conditions experienced during the winter of 2022-2023, and improve resilience in this area. Construction is planned to occur during 2025 for this project.

- The Beaverton Shaffer Road east of Alamando project involves the construction of 7050 feet of 12-inch steel high pressure main that will be constructed parallel to existing six-inch high pressure main out of the Coleman Beaverton City Gate station. This capacity expansion will improve delivery pressure in an area of growing demand. This project is planned for construction during 2025.

- The Crooked Lake Road - Latson Road project will construct 3,000 feet of six-inch medium pressure plastic main to create a looped system near the end of two existing distribution main systems. This augment project will improve deliverability by creating a back feed and increase the system pressure. The resilience of the system will also be enhanced by the looped system. This project completed construction during 2024.

- The Galesburg - Celery & River Street project will construct 6,900 feet of eight-inch high pressure steel main from the Galesburg city gate outlet to Comstock Avenue & Celery Street in the Kalamazoo area. This will create a looped system from the Galesburg City Gate high pressure outlet, increase the delivery pressure and reduce the risk of customer outages due to damage or failure. This project will complete construction before the end of 2024.

Additional augment supply projects are identified each winter as the Company records actual pressure readings and actual temperatures and uses them to further refine the piping system models. These projects tend to be smaller in nature (one mile or less) and therefore less expensive with shorter design and construction timeframes. The Company will continue to review system models and pressures to ensure reliability.

Q. Please describe Exhibit A-105 (LDW-6).

A. Exhibit A-105 (LDW-6), in accordance with Attachment 11 to the filing requirements prescribed in Case No. U-18238, provides the variances in the capital program amounts for the distribution programs which I am sponsoring to the Company's most recent general gas rate case, Case No. U-21490.

Q. Can you explain why columns (c), (e), and (f) of Exhibit A-105 (LDW-6) do not contain any data?

A. Yes, the information for column (c), the "Last Rate Case Approved Spending Plan Case No. U-21490," cannot be provided because Case No. U-21490 resulted in a settlement agreement that did not state approved capital spending amounts for the programs I am representing. Thus, column (c), the "Last Approved Spending Plan" cannot be calculated for those programs. Since there is no data to display in column (c) for these programs, the information for columns (e) and (f), which seek information concerning the variances from (c), cannot be completed.

II. IT PROJECTS

Q. Is the Company planning technology projects that support the engineering, asset planning, design, construction, and maintenance of a safe, reliable, and affordable distribution system for its customers?

A. Yes. Company witness Stacy H. Baker includes in her direct testimony and exhibits a number of technology projects that are critically important in supporting these gas functions within the Company. The expenditures for these projects are contained within the exhibits sponsored by Ms. Baker. The projects for the areas which I am sponsoring are described below:

- The **Gas Distribution Probabilistic Risk Model** project requires $1,017,283 in capital and $11,030 in O&M in the test year. The project will implement a risk analysis model for comprehensive predictive risk analysis and modeling on gas distribution pipeline assets. Relative risk models are unit-less measures of risk derived from input information using qualitative data and ordinal scales to produce "risk index" scoring; in simple terms, the relative risk model does not provide true statistical measures. The risk assessment used in the current model provides a score for likelihood, consequence, and risk that is relevant only in comparison to other scores. While the outputs provide a sense of relative risk when comparing one pipeline to another, the scores do not provide quantitative

scores for probability, frequency, or expected loss of events. Although pipeline operators commonly use relative risk models, the quality of the relative risk ranking relies on subject matter expert inputs, human inferences, and opinions. Completion of this project will provide value to both the Company and its customers. Each party will benefit from safety improvements and risk mitigation through statistically-based risk modeling that leads to more informed pipeline replacement or improvement projects. Implementing probabilistic risk modeling supports the changes planned for in the Company's NGDP, including the Company's Gas Safety Management System ("GSMS"). GSMS incorporates the Company's plan to implement the American Petroleum Institute ("API") Recommended Practice 1173 (Pipeline Safety Management Systems). Additionally, the implementation of a probabilistic risk model will: (1) calculate quantitative risk scores that include measures of probability, frequency, or expected loss of events; (2) configure multiple data sources to make advanced statistical calculations for interacting threats, both of which allow the Company to make more informed decisions based on improved quality inputs in a measurable model; and (3) provide information for better decisions on Capital project improvements and integrity management. Unlike the current unit-less relative model, a probabilistic model will be a unit based risk score, specifically in the unit of dollars, improving efficiency in interpreting risk results for business decisions. The project scope encompasses the implementation of a probabilistic risk model for gas distribution. The project will: (1) install and configure risk model; (2) configure multiple data sources; and (3) develop reports and dashboards. Alternatives considered for the project include: (1) Implement a custom, Excel based probabilistic risk model through a consulting effort. This alternative was not selected because although the effort minimizes the IT cost of the project, the model requires the creation of secondary data sources, leading to multiple "sources of truth". (2) Implement a custom built probabilistic risk model. This alternative was not selected because the custom built solutions analyzed are not mature and have not been widely tested with transmission operators. (3) Implement a SaaS based solution. The option of implementing the SaaS probabilistic risk model was chosen because it is the most cost-effective long-term implementation approach, providing commercial, off-the-shelf capabilities, industry-proven and upgradable technology, and ongoing vendor support.

- The **Gas Transmission and Distribution ("T&D") Historian** project requires $101,815 in capital and $37,450 in O&M in the test year. The Gas T&D Historian project will replace the current historian for Gas T&D, eDNA (a traditional SCADA historian product from Schneider Electric) and migrate to the standard OSIsoft PI enterprise historian system. The PI system is a suite of software products that are used to collect, store, view, analyze, and share operational data with system users and subject matter experts. The historian for Gas T&D resides on a decades old platform and is not the Company's historian standard. Data access is cumbersome, requires multiple tools to access it, and does not provide for the storing, analysis, or visualization of operational data in a timely manner with appropriate change management control. With the

implementation of smart meters, the Company standardized on the more robust OSIsoft PI historian which is used for: (1) Renewable Generation; (2) Electric T&D; and (3) Smart Energy. The Gas T&D historian has yet to be migrated to OSISoft PI, and the eDNA gas data has limited accessibility and usability in its current state and is no longer supported by the vendor. In addition, maintaining the older platform along with the new system requires duplicate resources and skills. This project will create a more accessible and centralized data source with better controls that can be leveraged as the system of record. The project will add value for both Gas Engineering and Gas Operations organizations within the Company by: (1) informing decision-making based on real-time data; (2) improving real-time situational awareness of Operations personnel for information that does not need to be monitored by Gas Control; (3) improving the ability to respond to abnormal situations that do not require immediate intervention through direct communication to Operations personnel; (4) providing information for the development of proactive analytics to reduce potential catastrophic events; (5) streamlining data access through visualization and analytics; and (6) reducing the waste of using multiple interfaces to interpret data. From an IT perspective, consolidating to one standard historian platform will result in savings in hardware, software, maintenance, resources and training. The scope of this project includes: (1) replacing the eDNA Gas T&D historian, a traditional SCADA historian, and migrating to the enterprise historian, OSIsoft PI; (2) developing analytics, visualization and reporting capabilities to support tracking of metrics and making operational decisions; (3) replacing the decades-old Microsoft Access-based custom Daily Gas Reports solution; and (4) retiring the legacy Gas T&D eDNA system (hardware and software). An alternative considered for the project was to upgrade eDNA Gas Historian to the latest version. This option was not selected because it requires a significant investment, and does not meet analytics, reporting, usability and accessibility needs as well as the software owner has announced the "sunset" for this software. Furthermore, the Company standard for historians is OSIsoft PI, and maintaining two platforms results in redundant efforts in training, support personnel, and technology. The option to replace eDNA with the Company standard OSIsoft PI historian was selected to eliminate duplicate training, support personnel, and technology, and to leverage more robust data analytic capabilities in the OSIsoft PI tool set. Currently the plan is to implement the Gas T&D Historian with the Gas SCADA Software Solution to eliminate the need to have duplicative historians while the Gas SCADA Software Solution is being implemented. If this project is not completed, an interruption of operational data reporting capabilities could occur and could result in a non-compliance and could potentially interrupt certain volumetric accounting and billing functions.

- The **Gas SCADA Software Solution** project requires $1,071,858 in capital and $171,959 in O&M in the test year. The Gas SCADA Software Solution project will replace the current Gas SCADA software with a more standardized software package enabling the Company to more efficiently meet Federal and MPSC requirements. The current Gas SCADA software solution was originally

implemented in 2000 and was based on the gas system requirements at that time. While the solution has been maintained since its implementation, the Company's gas system has outgrown the current capabilities. As the solution ages, there is increased effort required to address obsolete application and database software architecture, and enhancements to the system are limited. To address the capability gaps, custom interim fixes and integrations have been developed where each requires maintenance and support. This environment adds complexity and cost to solution upgrades and troubleshooting issues. The current Gas SCADA solution will limit the ability to invest in digital solutions for increased system health monitoring and preventative maintenance capabilities due to the complexity to integrate these future capabilities with it. The project will add value by: (1) reducing risk of non-compliance by improving the ability to document and follow State and Federal requirements, improving customer safety; (2) improving efficiency and reliability when performing routine software upgrades, because standard out-of-the-box software has less risk of breaking during upgrades, as opposed to more custom-coded software; (3) reducing maintenance costs due to fewer individual software programs and less custom code; (4) improving Gas Control management capabilities that support the Federal and MPSC requirements for gas pipeline and Gas Distribution companies; (5) improving reliability by using proven gas industry standardized software with configuration features, rather than a fully customized system that has the possibility of being impacted by the next version update; (6) purchasing standard, out-of-the-box software that meets a high percentage of requirements and avoids multiple custom applications and specially coded programs to achieve results; and (7) providing a basis for capturing data required for use in computer-based preventative maintenance programs and more predictive technologies. In addition, implementing industry-specific software helps the collective gas industry users to encourage the vendor development of future version enhancements, which adds more value to gas industry users. The comprehensive Gas SCADA system is used to monitor and control the operating conditions of the transmission and distribution gas systems. The Gas SCADA system includes remote terminal units ("RTUs"), field devices (i.e., valves, meters, odorizers), and computers running SCADA software. This scope covers the Gas SCADA software solution only. The project scope includes the following: (1) significant planning, including consulting assistance, to define the implementation strategy for the effort, given the magnitude of the technology effort; (2) selection and implementation of a new Gas SCADA software solution; (3) planning of a phased rollout of new hardware and software; and (4) retirement and decommissioning of the legacy Gas SCADA solution and equipment once the new system is fully tested and operational. Alternatives considered include: (1) continue to maintain the current solution, at the risk of increasing reliability issues that result in controlling and monitoring the Company's gas system; (2) invest in enhancing the existing Gas SCADA software solution which would introduce additional custom development and more specialized functions that may not be supported in future vendor releases; and (3) replace the solution

with a Gas SCADA software solution that meets requirements to support the NGDP. Alternative three has been selected to ensure sustainability for this critical solution. The current legacy system is operating at well beyond its original design specification, so the potential points of failure are not fully known or understood. If the SCADA project is not completed, the legacy system could become unstable and impact Gas Control's ability to operate and monitor real-time system conditions, maintain safe operations, and compliance with regulatory requirements. It could also impact the ability to commission new facilities which require remote monitoring or control or cause the need for 24/7 manual field monitoring of certain facilities.

- The **Tracking and Traceability** project requires $5,295,411 in capital and $508,607 in O&M in the test year. Tracking and Traceability is a project driven from proposed regulatory rules that will require utilities to map new and replacement installations with tracking and traceability data for plastic pipes, fittings, and fusions for the lifetime of the asset. The Company does not currently have a Tracking and Traceability program that will meet PHMSA proposed requirements (PHMSA-2014-0098), also known as the Plastic Pipe Rule. Tracking and traceability refers to the collection of information that provides manufacturing, material type, and location information for pipe and components. PHMSA defines the terms "tracking" and "traceability" as follows: (1) Tracking is information that provides for the identification and location of pipe and components, the date installed, and the person who made the joints in the pipeline system; and (2) Traceability is defined by the American Society for Testing and Materials ("ASTM") standard F2897-11a and includes a unique identifier for the location of manufacture, production lot information, size, material, pressure rating, temperature rating and as appropriate the type, grade, and model of pipe and components. PHMSA will be requiring each pipeline operator to maintain tracking and traceability information for the life of installed pipeline segments. The lack of adequate traceability for plastic pipe and tracking of pipe location prevents gas pipeline operators from having enough information to identify systemic issues related to incidents involving plastic pipe. The lack of this information makes it difficult for operators and regulators to determine whether plastic pipe or component failures are related to a certain type or vintage of material, specific product defect or design, heat/lot of the product, or whether it was produced by a certain manufacturer at a certain time. The lack of information can result in excessive pipe excavations due to an inability to locate the affected sections of pipe or fittings when responding to plastic pipe or component manufacturer recalls. This project will develop a sustainable Tracking and Traceability program that will meet PHMSA requirements (PHMSA-2014-0098) which address the proposed tracking and traceability requirements. The project adds value by capturing traceability data via barcode readers and location tracking information via Global Positioning System (or "GPS") equipment to improve the quality of data and assist the Company in determining future scopes of work in the event of any component manufacturer recalls. The scope of work will include:

(1) changes in SAP Supply Chain processes to capture the required barcode information for all plastic components used in gas distribution and service lines; (2) changes in SAP Work Management processes to account for capturing barcode information as part of material components added to work orders, capturing fusion information from work order completion and capturing GPS coordinates from work order completion; (3) changes in GIS to capture GPS coordinates of plastic components and GPS coordinates of component fusions; (4) building of a repository for tracking and traceability reporting and analysis; (5) purchasing barcode reading equipment for storerooms and gas distribution trucks; and (6) purchasing of GPS locating equipment to capture coordinates. Alternatives considered include: (1) The do nothing alternative, which was not selected because it would expose the company to significant legal and financial risk resulting from non-compliance; and (2) Internally develop digital technology that will support the tracking and traceability standards included in the PHMSA-2014-0098 plastic pipe rule. The second alternative is being pursued by the Company.

Q. Please summarize your direct testimony.

A. My direct testimony describes the Company's Gas Distribution capital investment requirements for specific programs that are required to operate a gas distribution system that is safe and reliable. The projections included in this testimony are needed to meet customer capacity demand and regulatory requirements, reduce leaks on the system, and protect public safety. I have described the importance of project coordination with other public infrastructure work as recognized by the MPSC through the SEA and the Michigan Infrastructure Council and demonstrated the Company's commitment to this coordination. The Company's NGDP will work to enhance the Company's gas distribution system and offer additional opportunities for similar collaboration with municipal partners. Through the implementation of the NGDP and the execution of the projects outlined in my direct testimony above (including the IT projects that support these distribution system projects),

investments that are both reasonable and necessary, the Company can provide a safe, reliable, affordable, and clean gas delivery system for its customers.

Q. Does this conclude your direct testimony?

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 distribution of natural gas and for other relief.	)))))	Case No. U-21806

PROOF OF SERVICE

STATE OF MICHIGAN)
) SS
COUNTY OF JACKSON)

Melissa K. Harris, being first duly sworn, deposes and says that she is employed in the Legal Department of Consumers Energy Company; that on May 23, 2025, she served an electronic copy of the **Redacted Revised Testimony of Consumers Energy Company Witnesses Luther A. Bonner, Quentin A. Guinn, Michael P. Griffin, James P. Pnacek, and Lincoln D. Warriner**, pursuant to the Protective Order in this case, upon the persons listed in Attachment 1 hereto, at the e-mail addresses listed therein.

Melissa K. Harris

Subscribed and sworn to before me this 23rd day of May, 2025.

Crystal L. Chacon, Notary Public
State of Michigan, County of Eaton
My Commission Expires: 05/25/30
Acting in the County of Jackson

ATTACHMENT 1 TO CASE NO. U-21806

Party	Mailing Address	Email Address
Administrative Law Judge		
Hon. James M. Varchetti	Michigan Public Service Commission 7109 West Saginaw Highway Lansing, MI 48909	varchettij@michigan.gov
Counsel for Consumers Energy Company		
Bret A. Totoraitis, Esq. Gary A. Gensch, Jr., Esq. Anne M. Uitvlugt, Esq. Spencer A. Sattler, Esq. Evan B. Keimach, Esq. Mark R. Ruszkiewicz	One Energy Plaza Jackson, MI 49201	Bret.Totoraitis@cmsenergy.com Gary.GenschJr@cmsenergy.com Anne.Uitvlugt@cmsenergy.com Spencer.Sattler@cmsenergy.com Evan.Keimach@cmsenergy.com Mark.Ruszkiewicz@cmsenergy.com mpsc.filings@cmsenergy.com
***Counsel for the Michigan Public Service Commission Staff**		
Michael J. Orris, Esq. Amit T. Singh, Esq. Anna B. Stirling, Esq. Alena Clark, Esq.	Public Service Division 7109 West Saginaw Highway Post Office Box 30221 Lansing, MI 48909	orrism@michigan.gov singha9@michigan.gov stirlinga1@michigan.gov clarka55@michigan.gov
Michigan Public Service Commission Staff		
Mike Byrne Bill Stosik David Chislea Bob Nichols Nick Revere Lori Mayabb*	Michigan Public Service Commission 7109 West Saginaw Highway Post Office Box 30221 Lansing, MI 48909	byrneM@michigan.gov stosikb@michigan.gov chislead@michigan.gov nicholsb1@michigan.gov reveren@michigan.gov mayabbl@michigan.gov
***Counsel for Attorney General Dana Nessel**		
Celeste R. Gill, Esq.	Michigan Department of Attorney General, Special Litigation Division 525 West Ottawa Street 6th Floor Williams Building Post Office Box 30755 Lansing, MI 48909	gillc1@michigan.gov AG-ENRA-Spec-Lit@michigan.gov
***Counsel for Citizens Utility Board of Michigan ("CUB"), Michigan Environmental Council ("MEC") and Sierra Club ("SC")**		
Christopher M. Bzdok, Esq. Holly L. Hillyer, Esq. Natasha Fowles	Troposphere Legal 420 East Front Street Traverse City, MI 49686	chris@tropospherelegal.com holly@tropospherelegal.com natasha@tropospherelegal.com
Counsel on behalf of Sierra Club ("SC")		
Nihal Shrinath, Esq.	2101 Webster St. Suite 1300 Oakland, CA 94612	Nihal.shrinath@sierraclub.org
Consultant for Citizens Utility Board of Michigan ("CUB"), Michigan Environmental Council ("MEC") and Sierra Club ("SC")		
Julielyn Gibbons* Douglas Jester* Rick Bunch* Josh Denzler* Ram Veerapaneni*	5 Lakes Energy 220 M.A.C. Ave., Apt. 218 East Lansing, MI 48823	jgibbons@5lakesenergy.com djester@5lakesenergy.com rbunch@5lakesenergy.com jdenzler@5lakesenergy.com ram@5lakesenergy.com
Matthew Bandyk* Alice Napoleon* Sol Deleon*	Synapse Energy Economics 485 Massachusetts Ave., Suite 3 Cambridge, MA 02139	mbandyk@synapse-energy.com anapoleon@synapse-energy.com sdeleon@synapse-energy.com

* Receives Confidential Materials

ATTACHMENT 1 TO CASE NO. U-21806

Sophie Schadler*		sschadler@synapse-energy.com
Nihal Shrinath	Sierra Club 2101 Webster St., Suite 1300 Oakland, CA 94612	Nihal.shrinath@sierraclub.org
***Counsel for the Association of Businesses Advocating Tariff Equity ("ABATE")**		
Stephen A. Campbell, Esq. Michael J. Pattwell, Esq. Benjamin J. Holwerda, Esq.	Clark Hill, PLC 500 Woodward, Suite 3500 Detroit, MI 48226	scampbell@clarkhill.com mpattwell@clarkhill.com bholwerda@clarkhill.com
Consultants for ABATE		
James Dauphinais Jessica York	Brubaker & Associates, Inc. P.O. Box 412000 St. Louis, MO 63141	jdauphinais@consultbai.com jyork@consultbai.com
Counsel for Retail Energy Supply Association ("RESA")		
Jennifer Utter Heston, Esq.	Fraser Trebilcock Davis & Dunlap, P.C. 124 West Allegan, Suite 1000 Lansing, MI 48933	jheston@fraserlawfirm.com
***Counsel for the Lansing Board of Water & Light ("LBWL") and Michigan State University ("MSU")**		
Nolan J. Moody, Esq. Cole V. Lussier, Esq.	Dickinson Wright PLLC 123 W. Allegan Street, Ste. 900 Lansing, MI 48933-1816	nmoody@dickinsonwright.com clussier@dickinsonwright.com
Counsel for LBWL		
Mark Matus, Esq.	Lansing Board of Water & Light 1201 S. Washington Avenue Lansing, MI 48910	mark.matus@lbwl.com
Counsel for Energy Michigan		
Timothy J. Lundgren, Esq. Laura A. Chappell, Esq. Justin K. Ooms, Esq.	Potomac Law Group 120 N. Washington Square, Suite 300 Lansing, MI 48933	tlundgren@potomaclaw.com lchappelle@potomaclaw.com jooms@potomaclaw.com
***Counsel for The Ecology Center, The Environmental Law & Policy Center ("ELPC"), Union of Concerned Scientists ("UCS"), and Vote Solar (collectively, "CEO")**		
Daniel Abrams, Esq. Alondra Estrada Carolyn Boyce	Environmental Law & Policy Center 35 East Wacker Drive, Suite 1600 Chicago, IL 60601	dabrams@elpc.org aestrada@elpc.org cboyce@elpc.org MPSCDocket@elpc.org

* Receives Confidential Materials