S T A T E O F M I C H I G A N

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the application of **CONSUMERS ENERGY COMPANY** for authority to increase its rates for the distribution of natural gas and for other relief.	)))))	Case No. U-21490

REDACTED

DIRECT TESTIMONY

OF

HEIDI J. MYERS

ON BEHALF OF

CONSUMERS ENERGY COMPANY

December 2023

Q. Please state your name and business address.

A. My name is Heidi J. Myers, and my business address is One Energy Plaza, Jackson Michigan 49201.

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

A. I am employed by Consumers Energy Company ("Consumers Energy" or the "Company") as the Executive Director of Revenue Requirements and Regulatory Affairs.

Q. Please describe your educational background.

A. I received a Bachelor of Arts degree in Accounting in 2003 from Michigan State University. I received a Master of Business Administration degree in 2012 from the University of Michigan – Flint. I am also a Certified Public Accountant licensed in the state of Michigan.

Q. Please describe your professional experience.

A. From 2004 to 2008 and from 2012 to 2015, I was employed by the Michigan Public Service Commission ("MPSC" or the "Commission") as an auditor and later as the Manager of the Revenue Requirements Section. From 2008 to 2012 and 2015 to 2017, I was employed by the Lansing Board of Water and Light ("BWL"). During my tenure at the BWL, I held the following positions: Senior Rate Analyst, Executive Financial Assistant, Field Services Supervisor, Manager of Human Resources, and Supervisor of Finance and Planning. I joined Consumers Energy in January of 2017 as a Principal Rate Analyst and was promoted to Director of Revenue Requirements and Analysis in March of 2018 and was promoted to Executive Director of Revenue Requirements and Regulatory Affairs in June of 2020.

Q. What are your responsibilities as the Executive Director of Revenue Requirements and Regulatory Affairs at Consumers Energy?

A. As the Executive Director of Revenue Requirements and Regulatory Affairs, I am responsible for regulatory stakeholder collaboration and project management for the development of regulatory filings and communications as well as managing and preparing studies related to the level of the Company's revenue requirements, including the preparation, and monitoring of gas and electric rate case filings before the Commission and other financial analyses. In addition, I oversee the calculation of the Company's Gas Cost Recovery and Power Supply Cost Recovery ("PSCR") monthly billing factors. Beginning in July of 2023, I also assumed responsibility for cost, pricing, and regulatory policy.

Q. Have you previously filed testimony with the Commission?

A. Yes.

Q. Please state the proceedings you have been involved in.

A. I sponsored testimony in the following cases:

Case No. U-14347 – Consumers Energy electric rate case;

Case No. U-14547 – Consumers Energy gas rate case;

Case No. U-17087 – Consumers Energy electric rate case;

Case No. U-17473 – Consumers Energy securitization;

Case No. U-18322 – Consumers Energy electric rate case;

Case No. U-20102 – Consumers Energy electric credit A;

Case No. U-20103 – Consumers Energy gas credit A;

Case No. U-20134 – Consumers Energy electric rate case;

Case No. U-20165 – Consumers Energy integrated resource plan;

Case No. U-20286 – Consumers Energy electric credit B;

Case No. U-20287 – Consumers Energy gas credit B;

Case No. U-20309 – Consumers Energy calculation C;

Case No. U-20697 – Consumers Energy electric rate case

Case No. U-20889 – Consumers Energy securitization; and

Case No. U-21389 – Consumers Energy electric rate case.

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

A. The purpose of my direct testimony is to provide an overview of the Company's gas general rate case filing. My testimony provides a summary of Consumers Energy and its commitment to delivering on the triple bottom line – supporting people, the planet, and Michigan's prosperity. I introduce key proposals included in this case and provide a brief introduction to the Company's witnesses and the topics supported in their respective testimony. [redacted]

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

A. No, I am not.

<u>COMPANY OVERVIEW</u>

Q. Please provide a brief description of Consumers Energy and its service territory.

A. Consumers Energy is a combination electric and gas utility that has powered Michigan's progress for 137 years. Today, the Company provides natural gas service to approximately 1.8 million customers in Michigan's lower peninsula.

Q. Please explain Consumers Energy's commitment to the triple bottom line.

A. The Company's focus on the triple bottom line provides a broader view of success than just profitability. The triple bottom line means we are successful when the Company's customers and employees succeed, when we protect the health of the planet, when we help the communities we serve and the state of Michigan to prosper. The Company's triple bottom line approach seeks to balance the interests of customers with other stakeholders while internalizing the broader societal and environmental impacts associated with the Company's activities. The triple bottom line broadens the Company's perspective and helps reinforce our commitments to providing safe, secure, reliable, and affordable service while positioning the Company for success now and in the future.

<u>CASE OVERVIEW</u>

Q. Please summarize the key drivers of the Company's request in this case.

A. The Company requests rate relief in the amount of $122 million, which is summarized in Table 1:

Table 1

		(In Millions)
Investment	**$**	**75**
Cost of Capital	**$**	**45**
Sales/Revenue	**$**	**30**
Operating Expenses	**<u>$</u>**	**<u>(14)</u>**
Rate Relief Before Credit	**$**	**136**
[redacted]	[redacted]	
[redacted]	[redacted]	

Q. How does this request impact residential customer bills?

A. The Company anticipates that the average monthly residential bill for the 12 months ending September 2025 will increase by 5.1% over current rate levels. If the entirety of this request is approved, Consumers Energy expects that the average residential natural gas customer will pay approximately $2.90 per day in 2025 for the natural gas service that provides an affordable fuel for heating, cooking, and hot water.

The Company is aware that this increase will challenge some customers more than others and offers assistance programs to customers who may continue to be more impacted. Examples of this assistance include Consumers Affordable Resource for Energy Program, the Residential Income Assistance Provision, and the Low-Income Assistance Credit. The Company has also implemented a Percent of Income Payment Plan ("PIPP") Pilot for low-income customers. These programs are designed to assist customers with the management of their energy use and bills. In addition to these provisions and programs, the Company and its employees are generous contributors to community-based groups, including the United Way, the Salvation Army, the Heat and Warmth Fund, and many community service organizations. The Company works to keep its requested price increases to the lowest level it believes is reasonable, while balancing the need for safety, reliability, improved customer service and increasingly clean natural gas service.

Q. How does the outcome of Consumers Energy's most recent gas general rate case impact the requested rate relief in this case?

A. Consumers Energy's most recent gas rate case, Case No. U-21308, resulted in a Commission-approved Settlement Agreement with new rates that were implemented in October 2023. Consumers Energy continues to invest in its natural gas system and supporting infrastructure; therefore, this application includes the request to recover actual and projected costs related to these ongoing investments. As shown in Table 1, this request is largely driven by new investment.

Q. Are there any provisions from the Settlement Agreement in Case No. U-21308 that impact this filing?

A. Yes. As provided in the settlement, this filing contains the 2022 Gas Enhanced Infrastructure Replacement Project ("EIRP") Annual Performance Report as Exhibit A-98 (KAP-6). Also, as captured in Company Witness Yong F. Keyes's Exhibits A-86 (YFK-3) and A-87 (YFK-4), this filing includes a Cost-of-Service study version that shows a more granular allocation of Other Distribution Plant by FERC account, and calculates the impact of utilizing the Average and Excess allocation and allocating Other Distribution Plant between High Pressure and Non-High Pressure. Additionally, as referenced by Company witness Kirkland D. Harrington and agreed to in settlement, the Company met with MPSC Staff and gas suppliers to discuss the Company's Group Transportation Service Pilot Program.

Q. How do the Company's proposals in this case support the Company's Natural Gas Delivery Plan?

A. Consumers Energy has plans for investing in its natural gas system over the course of the next decade to ensure customers continue to receive safe, reliable and affordable natural gas while transforming the system to deliver cleaner fuels for a decarbonized future. The Natural Gas Delivery Plan ("NGDP") outlines the Company's 10-year plan to invest approximately $12.3 billion in the natural gas system.

The proposals in this rate case support the objectives of the NGDP. Company witnesses Neil P. Dreisig, Timothy K. Joyce, Michael P. Griffin, Lincoln D. Warriner, Kristine A. Pascarello, and James P. Pnacek provide support for the transmission and distribution system investments and Operating and Maintenance ("O&M") programs. The Company's proposed natural gas investments include capital investments planned for the test year, the 12 months ending September 2025, that total more than $1.1 billion. These investments are comprised of several important programs detailed in this case, such as Material Conditions, Compression and Storage, Well Rehabilitation, Asset Relocation, Regulatory Compliance, and New Business.

Q. Why is Consumers Energy making significant natural gas investments?

A. Consumers Energy has built and maintained a complex natural gas system comprising approximately 30,500 miles of distribution and transmission pipelines. The Company operates 15 storage fields and 8 compressor stations, and all these systems have served customers well for decades, allowing access to a diverse natural gas supply and leveraging the unique size of the Company's storage fields to time gas purchases and stabilize pricing. It is crucial that Consumers Energy continues to invest in the system to ensure natural gas is delivered safely, reliably, and affordably to the approximately 1.8 million natural gas customers who rely on it every day.

Q. How should stakeholders view the Company's significant natural gas investment?

A. Consumers Energy's investment represents its commitment to modernizing the Company's natural gas pipeline and continued improvements in energy efficiency. The EIRP continues to replace significant portions of our infrastructure annually, resulting in a safer, more resilient system that has fewer leaks, thereby reducing carbon emissions. Additionally, the

Company continues to work with third parties through its damage prevention program and third-party coordination to mitigate and reduce third-party-caused leaks on the system. The investments outlined in the NGDP express the multitude of initiatives the Company is undertaking to ensure the sustainable delivery of safe, reliable, clean, and affordable energy to customers.

Q. Please describe the Company's support for the Digital Plan.

A. The Company has a strong and increasing dependence on technology and related proposals in this case that are necessary to enable essential business capabilities outlined in the Digital Plan. The Company's investments and O&M spending represented in the Digital Plan address the new technical capabilities needed to deliver on the goals of the NGDP, as well as programs for customer offerings and engagements, including expanding system monitoring to support 24/7 system control, incorporating predictive and condition-based maintenance, and offering customers tools to understand their energy consumption. Specifically, the Company's Digital Plan presents a clear and inclusive view of the Company's Information Technology ("IT") plans over the next three years and how these plans support the business planning needs into the future. Company witness Stacy H. Baker supports the Company's Digital Plan, provides support for the Company's IT Department Operation O&M expense, and details the Investments and O&M required for the Company's technology systems. Ms. Baker provides detailed project synopses for the different proposals included in her testimony along with careful documentation of project costs and cost benefit estimates. Without these new digital capabilities, the Company will be limited in its ability to achieve key strategic outcomes of its NGDP.

Q. How do security proposals, supported by the Digital Plan, provide value to customers?

A. In addition to investments in IT, the Company proposes continuing investments in the Security Department's ability to provide 24/7 physical and cyber security to ensure protection for the Company's critical infrastructure and maintain customers' privacy by keeping their sensitive data safe. Security risks to the Company have never been greater, and the Company must keep pace with the rising threats to maintain essential services and recover quickly in the event of a security incident. Company witness Bradley S. Bammert addresses the Company's proposals for security. The Company is improving its focus on security across its operations with increased staffing levels to support 24/7 security monitoring through the Fusion Center — a dedicated team with oversight for physical and cyber security, increased use of cloud computing solutions, and ongoing investment in maturing security capabilities to protect technology and physical infrastructure.

Q. Does the Company evaluate major capital projects and O&M expenses on an ongoing basis?

A. Yes. The Company continually evaluates and adjusts its planning for a variety of factors including (i) sales and revenue expectations and results, (ii) infrastructure investments and the cost of capital, (iii) O&M expense expectations and results, and (iv) the impact of several other variables that may change over time (including changes to environmental laws and requirements, Commission orders, weather, customer demands, commodity prices, financing costs, changes in economic expectations, etc.). In any one period, the Company's capital investments and its O&M expenses may vary from what was expected in a prior period. The Company plans for this continually changing environment, and its witnesses have provided highly detailed and thorough support for capital expenditures and O&M expenses.

The individual witnesses addressing capital and O&M costs in this case explain the reasons for these expenditures. The Company employs a rigorous management review process, which ensures that the allocation of O&M and capital resources are optimized such that the Company's strategic, financial, and operational plans are aligned to deliver customer value. The Company maintains a portfolio of investment opportunities from which to make investment decisions, with the goal of maximizing customer value while minimizing the cost impact to customers. While the Company must retain the flexibility to react to changing conditions, the proposed expenditure levels included in this case reflect the Company's commitment to meet its legal obligations and improve service reliability and quality for customers.

Q. Does the Company anticipate the need to flex spending between programs in the test year?

A. Yes. The Company's plans provide its best estimate of the total cost it expects to spend on each program. However, when actual dollars are spent in the test year, unforeseen circumstances (such as new business, extreme weather, or unanticipated civic improvement projects undertaken by state or local governments, for example) may require the Company to adjust the spending between programs. In any given year, the Company may be required to undertake unplanned natural gas distribution infrastructure replacement projects. In this circumstance, the Company would need to compensate for this unforeseen spending by adjusting the amount it intended to spend on another program. It is not possible for Consumers Energy to anticipate every event or circumstance which may cause it to incur costs on behalf of its customers, so it is prudent to allow for some flexibility in spending. Due to this circumstance, the Company would then need to adjust spending in another program to compensate for this additional spending. It is not possible for the Company to anticipate every event or circumstance that will arise multiple years from now; therefore, the need to have flexible spending between programs is prudent and in the best interest of the customer.

Q. Is the Company requesting to continue a Defined Benefit ("DB") Pension/Other Post-Employment Benefits ("OPEB") Volatility Mechanism?

A. Yes. DB Pension/OPEB expenses are sensitive to changes in asset returns or other assumptions that create a significant potential for volatility in future expenses. As discussed in the testimony of Company witness Kendra K. Grob, as a result of the Company's U-21308 settlement agreement, the Commission authorized the Company to implement a volatility mechanism. In the instant case, the Company is requesting the ability to continue the mechanism which provides benefit to customers by eliminating the risk of future expense volatility.

[redacted]

[redacted]

[redacted]

INTRODUCTION OF WITNESSES

Q. Please identify the other witnesses presenting direct testimony in support of the Company's filing and the topic that each witness will be addressing.

A. The following witnesses will also be providing testimony on behalf of Consumers Energy in this filing:

- **Stacy H. Baker** supports the IT Departments, capital expenditures and O&M expense, supported by the Digital Plan, that is needed to maintain existing IT systems, enable new security capabilities, and support other technology needs as proposed in the case.

- **Bradley S. Bammert** describes the Company's capital spending and O&M expenses related to cyber security operations and physical security, as well as the need for increased staffing and O&M to respond to evolving security threats and a changing regulatory landscape.

- **Marc R. Bleckman** supports the Company's proposed capital structure and cost of capital which should be used in computing overall rate of return. Mr. Bleckman also provides support for the level of cash included in the Company's test year working capital.

- **Adam S. Carveth** describes the function and needs of the Company's fleet services and supports the fleet capital investment and electrification strategy.

- **Amy M. Conrad** describes the Company's overall compensation philosophy and provides support for the recovery of costs related to the Company's annual Employee Incentive Compensation Program ("EICP") at target levels.

- **Neal P. Dreisig** provides an overview of the Company's gas transmission, distribution, and storage and compression systems along with an updated version of the Company's 10-year plan or the Natural Gas Delivery Plan.

- **Matthew J. Foster** supports the Company's Corporate Services O&M expense which includes uncollectible expense, and injuries and damages. Mr. Foster's testimony also supports Corporate Services capital spending, IT projects supporting Corporate Services, manufactured gas plant remediation cost recovery, and the request for certain accounting approvals.

- **Michael P. Griffin** supports certain gas transmission and distribution capital and O&M expenses primarily related to the operations of the Company's high-pressure distribution and transmission system.

- **Kendra K. Grob** supports the Company's costs related to retirement, health care, life insurance, long-term disability plans, and other benefits provided to its employees and retirees. Ms. Grob's testimony also supports the continuation of the Defined Benefit Pension/Other Post-Employment Benefits Volatility Mechanism.

- **Quentin A. Guinn** describes the function and needs of the Company's facilities and supports proposed capital spending and O&M expenses related to the Gas business portion of Facility Operations.

- **Kirkland D. Harrington** presents the Company's proposed tariff language changes to its gas rate schedules.

- **Timothy K. Joyce** supports the Company's Gas Compression and Gas Storage Capital spending and Gas Compression O&M expense. Mr. Joyce's testimony also sponsors IT projects supporting Gas Compression and Gas Storage, cost of gas sold and underground, lost and unaccounted for gas, and company use gas.

- **Eric J. Keaton** supports the Company's gas revenues and deliveries in the test year.

- **Yong F. Keyes** sponsors the Company's gas cost of service study that conforms to methods previously approved by the Commission. She also provides a version 2 cost of service study that incorporates Company proposals addressing cost of service study issues raised in Case No. U-21308.

- **Steven Q. McLean** describes the work performed by the Company's Customer Experience & Operations organization and how this work benefits customers. Mr. McLean also supports the capital investment and O&M expense associated with executing this work. [redacted]

- **Kristine A. Pascarello** supports Gas Engineering and Supply O&M expense as well as certain gas distribution capital investments.

- **James P. Pnacek** supports Gas Operations Division O&M expense as well as certain gas distribution capital investments. Mr. Pnacek also sponsors IT projects supporting the Gas Operations Division.

- **Heather M. Prentice** describes former manufactured gas plant ("MGP") sites at which the Company has a present or former ownership interest and provides environmental requirements for investigation and remediation. Ms. Prentice also identifies and describes expenditures for associated environmental response.

- **Heather L. Rayl** presents the historic and test year revenue deficiency. Ms. Rayl also presents support for requested approval to follow Federal Energy Regulatory Commission accounting treatment for first-time and one-time maximum allowable operating pressure ("MAOP") retesting costs.

- **Austin Smith** presents the Company's rate design proposals.

- **R. Michael Stuart** discusses operational performance goals included in the Company's EICP and how the EICP goals provide benefits to customers.

- **Brian J. VanBlarcum** supports the Company's real and personal property taxes as well as the excess deferred federal income taxes being returned to gas customers because of the Tax Cuts and Jobs Act of 2017.

- **Lincoln D. Warriner** supports certain gas distribution capital investments related to the New Business, Asset Relocation, Regulatory Compliance, and Capacity/Deliverability programs.

- **Todd A. Wehner** supports the Company's proposed return on equity that should be used in computing the overall rate of return.

Q. Please summarize your direct testimony.

A. Consumers Energy respectfully submits this request for $136 million in annual rate relief [redacted] Consistent with Consumers Energy's commitment to provide exceptional value and service to every customer, caring for the communities where we live and work, and delivering on investor expectations, the Company is requesting revenue recovery for infrastructure investments that primarily support the NGDP, the Three-Year Digital Plan, as well as other programs that will enhance the customer experience. Consumers Energy is committed to delivering customer value and improving customer service and believes that this filing is a representation of the commitment put forth in the Company's purpose – World Class Performance Delivering Hometown Service.

Q. Does this complete your direct testimony?

A. Yes.

S T A T E   O F   M I C H I G A N

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the application of	)	
CONSUMERS ENERGY COMPANY	)	
for authority to increase its rates for the	)	Case No. U-21490
distribution of natural gas and for other relief.	)	
______________________________________	)	

DIRECT TESTIMONY

OF

STACY H. BAKER

ON BEHALF OF

CONSUMERS ENERGY COMPANY

December 2023

Q. Please state your name and business address.

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

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

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

Q. Would you please state your educational background?

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

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

A. Yes. I testified in Case No. U-21308.

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

A. The purpose of my direct testimony is to describe the IT Department's Operating and Maintenance ("O&M") expenses and capital expenditures needed to maintain and secure existing IT systems and to enable new capabilities and various types of programs (e.g. investment programs, customer programs) and services for the benefit of the Company's customers. My testimony will also describe how our increasing use of technology to benefit customers and how the Company's digital investments are part of a larger Digital Plan. In addition, my testimony will describe the Company's IT organization's transformation toward a product operating model where teams are funded and planned based on outcomes and business objectives. Lastly, my testimony will demonstrate why it is important to achieve full recovery of the requested expenses and expenditures to provide the best value to the Company's customers.

Q. What is the biggest challenge the IT Department currently faces?

A. The biggest challenge the IT Department currently faces is keeping existing technology safe and healthy while building new digital capabilities the Company needs to support the Company's Natural Gas Delivery Plan ("NGDP") and Customer plans through full regulatory recovery. The Company is challenged by the balance between supporting and securing aging systems, building new technology capabilities, and keeping rates affordable.

Q. Please summarize the main portions of this testimony.

A. My direct testimony discusses the following:

- Review of the Digital Plan;
- The importance to customers of digital investments and the role of IT to build and support those investments;
- Describe the Company's IT organizational transformation to a product operating model;
- Support for Operational O&M expense funding;
- A description of the Investment O&M and capital needed to keep the Company's systems secure, current, stable, and supporting new capabilities;
- Definition and rationale for the use of Rough Order of Magnitude ("ROM") estimates and explanation of the difference from contingency requests;
- Exhibit A-20 (SHB-5) and explanation for projects to provide additional information and address previous MPSC concerns, including:
  - Company total one time project cost across multiple years,
  - Total Company cost of ownership of each project beyond initial one-time project investment,
  - Recurring hard savings over the life of the investment, and
  - Cost benefit ratio calculated by the Company's internal Business Planning System ("BPS");
- Individual project synopses and requests to support gas and customer business drivers as described in the Digital Plan;
- Individual project synopses and requests to support corporate functions crucial to running an efficient business;
- Individual IT project synopses with supporting detailed exhibits for the Asset Refresh projects and the Application Currency projects;

- Individual IT project synopses with supporting detailed exhibit for Enhancement projects and Exhibit A-25 (SHB-10) providing a detailed worklist of the enhancement work backlog;
- Individual IT project synopses for the IT/Digital Foundations and Capabilities projects; and
- Further value and justification of variances for several larger and more complex projects for which the Company is requesting capital recovery, including:
  - Asset Refresh Program ("ARP") – Local Area Network ("LAN"),
  - ARP – Workstation Asset Management ("WAM"),
  - Enterprise Service Bus ("ESB") Application 2020 – 2021 Upgrade, and
  - Digital–Hybrid Cloud and Data Center Migration.

Q. What exhibits are you sponsoring in this proceeding?

A. I am sponsoring the following exhibits:

Exhibit A-17 (SHB-1)	Summary of Actual and Projected Information Technology Operations O&M Expense for the Years 2022, 2023, 9 Months Ending September 30, 2024, and Test Year 12 Months Ending September 30, 2025;
Exhibit A-18 (SHB-2)	Historical and Projected 13-Month Average of IT Cloud Computing Prepaid Balance for the historical years 2022 - 13-month balance ending June 30, 2022, and for the projected years 2024 – 13-month balance ending September 30, 2025;
Exhibit A-19 (SHB-3)	Summary of Actual and Projected Information Technology Investments O&M Expense for the Years 2022, 2023, 9 Months Ending September 30, 2024, and Test

		Year 12 Months Ending September 30, 2025;
Exhibit A-12 (SHB-4)	Schedule B-5.1	Projected Capital Expenditures Information Technology Summary of Actual and Projected Gas and Common Capital Expenditures;
Exhibit A-20 (SHB-5)		Synopses Containing Descriptions, Scope, Benefits, Implementation Dates and Detailed Costs of Actual and Projected Gas & Common Capital Expenditures and O&M Expenses For the Years 2022, 2023, 2024 and 2025;
Exhibit A-21 (SHB-6)		Business Case Executive Summaries for Historical, Bridge Period, and Test Year Projects;
Exhibit A-22 (SHB-7)		Asset Refresh Programs Projected Gas and Common Capital Expenditures, For the Projected Year 2023 and Test Year Ending September 30, 2025, and For the Historical and Projected Years 2022 and 2023;
Confidential Exhibit A-23 (SHB-8)		Application Currency Programs Projected Gas and Common Capital and O&M Expenditures for the Years 2024, 2025, and Test Year 12 Months Ending September 30, 2025;
Exhibit A-24 (SHB-9)		Projected Versus Actual Enhancement Capital Expenditures and O&M Expense Summary and Analysis;

Exhibit A-25 (SHB-10)	Enhancement Worklist Detail for Years 2016 through October 19, 2023; and
Exhibit A-26 (SHB-11)	Consumers Energy Digital Three-Year Plan for the Years 2023 – 2025 (Appendix B – Confidential).

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

A. Yes.

DESCRIPTION OF THE IT DEPARTMENT

Q. Please describe the purpose of the IT Department.

A. The purpose of the IT Department is to provide and maintain reliable and secure digital solutions and services that support the delivery of excellent customer experiences and other business objectives, including execution of the Company's NGDP. The IT Department strives to find the appropriate balance of value and cost in digital solutions. The Company's evolving and pragmatic approach to digital supports:

- Adaptable delivery practices (e.g. adopting Agile frameworks and a product-centric operating model) to execute work in an efficient and effective manner;
- Widespread building and use of digital skills and practices for co-workers to work in ways that deliver business value faster to ensure the Company meets customer expectations;
- A move to cloud solutions where and when appropriate to reduce cost, improve security, and increase speed of providing new capabilities;
- Treating data as an asset and deployment of analytics on a larger scale for better decision making, optimization of existing assets, and better investment prioritization;
- Deployment of a consistent asset management system and framework to reduce risk, optimize, and digitize processes resulting in waste reduction;
- Deployment of integrated control systems for system automation to increase system health monitoring and preventative maintenance capabilities;

- Continuous operational improvements via automation to gain efficiencies and reduce costs;
- A commitment to ensure digital investments do not introduce unnecessary risk to the Company or its customers and to protect sensitive data and critical infrastructure from cyber threats; and
- Evaluating current strategic platforms to ensure they are fully optimized and implementing enhancements to existing technologies as needed to provide new functionality for emergent business and customer value.

Q. Please describe the functions the IT Department performs.

A. The IT Department provides secure digital solutions and services to the Company's customers and internal business units through the identification, delivery, operational support, and maintenance of both on-premise and cloud software solutions and computing and communications infrastructure. Included in the scope of the IT Department is OT. OT is the set of real-time industrial control systems that monitor and control the Company's critical gas infrastructure, such as the Gas Supervisory Control and Data Acquisition ("SCADA") systems. The IT Department also provides the day-to-day operational support for each individual user of technology, whether that technology is a desktop, laptop, or mobile device (e.g. ruggedized field device, tablet computer, cell phone, smartphone, or other handheld device).

Q. Why did the Company develop the Digital Plan?

A. Digital capabilities delivered, supported, and operated by IT are necessary to implement the Company's business plans, including the NGDP, and customer offerings and engagements. The effort to develop and maintain the Digital Plan was designed to provide a clear and inclusive view of IT's plans over the next three years and how they closely align with the Company's long-term business plans that go beyond the horizon of this filing. The spend corresponding to the investment and operations of digital capabilities is largely centralized under IT for visibility, control, and optimization of a growing asset base. The Digital Plan provides the Company a mechanism to share and demonstrate the logical relationship and impact that digital capabilities and decisions have on the Company's business plans, capabilities, and goals. The Digital Plan reflects the strong dependency the Company has on technology. Funding requests contained within my testimony are necessary to enable the business capabilities contained within the Digital Plan.

Q. Is the Company providing the Digital Plan in this proceeding?

A. Yes. The Company's Digital Plan is provided as Exhibit A-XXX (SHB-11). This exhibit represents the latest revision of the Digital Plan at the time of filing. Appendix B is confidential.

Q. How does technology support the Company's NGDP?

A. The NGDP outlines the need to invest in both IT and OT to provide the following essential digital capabilities that will enable the Company to deliver safe, reliable, and affordable natural gas to customers while transforming the system to deliver cleaner fuels for a decarbonized future. These include: (1) Expanding system monitoring to support 24/7 system control; (2) Improving data analytics to support asset reliability and identification of optimal utilization of compression and storage assets; (3) Modernizing the distribution and transmission system; (4) Incorporating predictive and condition-based maintenance; (5) Transforming work and asset management; (6) Ensuring cyber security of Company assets and complying with security-related regulations; and (7) Achieving methane reductions.

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

The use of technology is also essential to establishing data analysis techniques to understand, communicate, and engage with the Company's customers in a meaningful way; connecting with customers using their channel of choice; enhancing the Company's digital resources in response to growing customer feedback that they prefer "self-service" through digital channels; providing customers accurate, timely energy bills and consistent payment processes, and offering options for customers to understand their energy consumption.

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

A. Yes. The current and emerging cyber-attack trends are evolving, and the number of threats is increasing in impact and sophistication as further described in the direct testimony of Company witness Bradley S. Bammert. Today, ransomware is one of the greatest security risks an organization faces, with a recent example being the prominent ransomware attack on the Colonial Pipeline in June of 2021. The increasing threats and impactful events have resulted in additional regulation and security requirements for the Company. Following the Colonial Pipeline ransomware attack, the Transportation Security Administration, who regulates gas pipelines as part of the Department of Transportation, issued two directives that required immediate action by gas asset owners and operators. Included in the second directive were security requirements that resulted in the IT Department shifting priority and executing significant work efforts to comply, including meeting requirements on systems common to both gas and electric.

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

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

A. Yes. To address changing security threats and vulnerabilities, vendors regularly release security fixes or "patches" to their products. The increased volume of threats to digital assets heightens the need to keep systems current and timely security patching is a key control for any security program. Technology vendors establish timelines for versions of their product they no longer support or no longer provide security updates or patches for. Where the Company may have had more discretion in the past to defer upgrades, it now must ensure the appropriate upgrade or replacement frequency to meet security requirements. Patching analysis, patch application, and patch tracking activities are all considered Operations O&M expenses. The Company fully expects this trend to continue indefinitely as more technology assets require the appropriate level of security to protect them. Therefore, recovery of asset refresh programs, application currency, upgrades and replacements, and the operational expenses related to security are important for the protection of Company assets and customer information.

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

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

Q. What is a product operating model?

A. A product operating model is where Agile teams are funded and planned based on outcomes and business objectives, rather than projects. With project-based funding, efficiencies and momentum are lost when Agile teams are disbanded at the close of each project. With a product operating model, the durable Agile teams will remain intact and continue to become more efficient and skilled in the technologies and business applications centered around a "product" and its associated outcomes.

Q. What is a product and product line?

A. A product is a group of applications or systems that provide the digital capabilities for a related set of business processes. A product line is a group of related products.

Q. Why has the Company's IT organization moved towards a product operating model?

A. As discussed in the Digital Plan (Exhibit A-26 (SHB-11) starting at page 33, the Company's IT organization has moved towards a product operating model where teams are aligned and funded around products to be able to deliver faster on planned initiatives and gain the agility to change course quickly in response to shifting business or customer needs, or to take advantage of emerging technologies to achieve the most value for operations and investments based on business outcomes.

Q. What business categories or product lines has the Company defined in the IT Organization?

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

<u>OPERATIONS O&M EXPENSES—MAINTAIN AND OPERATE EXISTING ASSETS</u>

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

A. The Company uses Operations O&M expense to provide the required level of operational support, reliability, and security for technology investments approved in prior and current rate cases. Operations O&M expenses include fixed and variable ongoing costs. Fixed costs include software vendor maintenance agreements, cloud subscription contracts, annual license contracts, and application support through managed services contracts. Software and cloud solution vendors typically increase these fixed costs on an annual basis. Variable costs include labor for equipment monitoring, break/fix activity, maintenance activity, disaster recovery, security improvements, software patching, and cloud usage costs. The activities associated with the fixed and variable costs are required to keep the Company's digital and information assets protected and performing at sufficient levels. The Company's customers benefit from the system stability and reliability that results from the activities funded by IT Operations O&M expense through emergency response, 24x7 billing, payment and usage services, contact center support, new service installations, and a myriad of other digital offerings. Gaps in the recovery of Operations O&M cannot be recovered in future rate case filings, which is why disallowance is impactful to the Company's ability to maintain and secure its systems.

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

A. There is a variety of operational work required to keep IT and information assets protected from cyber threats. First, security tools must be kept functional on all relevant technology. These include software to collect logs, scan for vulnerabilities, detect intrusions, and provide antivirus and encryption services. Second, IT resiliency must be kept up to date ensuring backup data and redundant infrastructure are in place in the event of a cyber intrusion. Third, as described previously, systems must be patched on a regular basis in accordance with security requirements. Vendors regularly release security updates that must be tested to ensure these updates do not introduce negative impacts to Company specific- configurations when deployed. Fourth, as cyber security standards and requirements change, IT teams must implement the appropriate corresponding technical changes on existing systems to ensure Company assets remain secure. The Security Department publishes and maintains enterprise security standards which include the technical requirements for IT to follow. The Security Department regularly updates standards to maintain the appropriate posture with the Center for Internet Security framework, as well as compliance with cyber security related governmental regulation.

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

A. Exhibit A-17 (SHB-1) is a Summary of Actual and Projected IT Operations O&M Expense for the Years 2022, 2023, 2024, and 12 months ending September 30, 2025. Page 1 provides a summary of the gas allocation of actual and projected IT Department operational expenses. Specifically:

- Column (a) provides the Operations O&M expense category;
- Column (b) identifies the 2022 historical Operations O&M expense as \$25,858,000;
- Column (c) identifies the 2023 projected Operations O&M expense as \$25,130,000;
- Column (d) identifies the 2024 projected Operations O&M expense as \$25,235,000;
- Column (e) identifies the three months ending December 31, 2024 projected Operations O&M expense as \$6,248,000;
- Column (f) identifies the nine months ending September 30, 2025 projected Operations O&M expense as \$18,897,000;
- Column (g) identifies the 12 months Test Year projected Operations O&M expense as \$25,235,000;
- Column (h) identifies the 2025 projected Operations O&M expense as \$23,900.000; and
- "Labor" line items include employee labor, and "Contracts" line items include hardware and software licenses and maintenance, staff augmentation, the Company's managed services contracts, and other contracted services. "Business Expense" line items include employee training, wireless plans, and supplies. "Material" line items include individual computer peripherals, tools, supplies, and replacing failed components such as hard drives.

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

- Column (a) is a description of the categorical expense;
- Column (b) provides the historical O&M expense;
- Column (c) provides the historical amount that an inflation rate or merit increase rate was applied to;

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

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

A. IT does not apply inflation in all categorical spend projections for Operations O&M expense. Merit increase is the primary method for labor projections; however, the labor projection is a net reduction of $1,189,000 based on an anticipated decrease in headcount offset by the merit increase based on inflation. Inflation is not used to project any other categorical spend projections for Operations O&M expense. Future contract expenses are projected based on annual increases for current commitments for contract expenses and the addition of new contracts because of ongoing and new project implementations before or during the test year period. Business expense and Material are projected based on historical spend and known adjustments for employee training needs, wireless plans, and supplies.

Q. Please describe the projected IT Department Operations O&M expense for 2022 and 2023, as reflected in Exhibit A-17 (SHB-1).

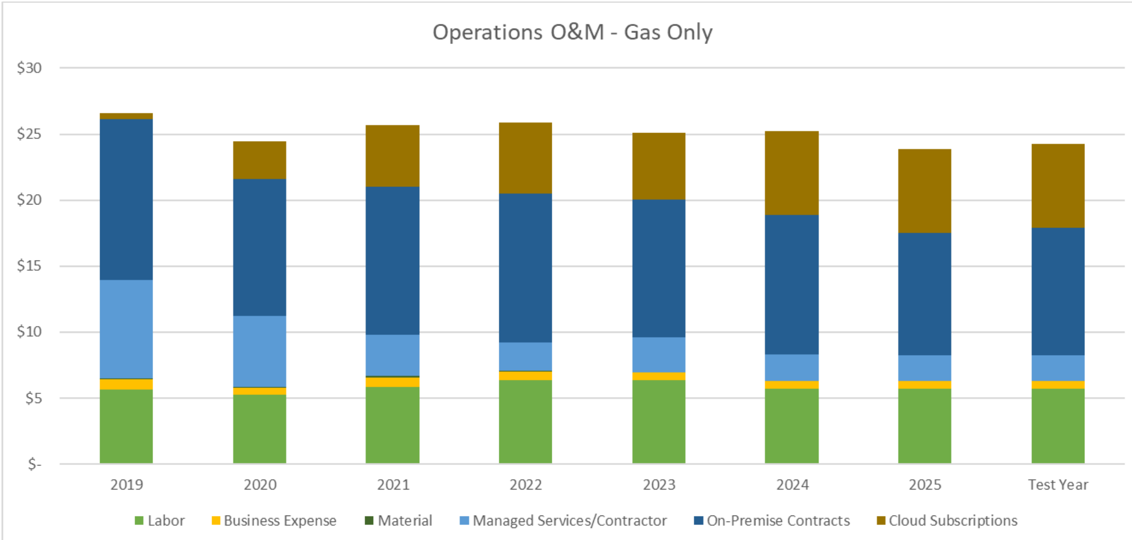
A. The Operations O&M expense in 2023 of $25,130,000 is projected to be 3% less than 2022. The reason for the net decrease in 2023 is the result of cost optimization efforts offset by the necessity to fund continued investment in programs to sustain and improve the customer experience; to maintain, improve, and secure critical enterprise systems that support the Company's NGDP; and to prevent obsolescence and risk to business operations. Key drivers for the change from 2022 to 2023 include: (1) net labor is unchanged based on merit increases offset by reductions in resources; (2) net decrease in cloud subscriptions ($.28 million), as described in detail later in my testimony; (3) net decrease in business expense and material ($.16 million); (4) increase in managed services/contractor ($.53 million); and (5) net decrease in license and maintenance agreements due to cost optimization efforts ($.84 million).

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

A. The Operations O&M expense in 2024 of $25,235,000 is projected to be flat with 2023. The reason the Company is projecting no increase in 2024 is the result of plans to identify cost optimization opportunities to offset increases because of the continued investment to maintain, improve, and secure critical enterprise systems that support the Company's NGDP; and to prevent obsolescence and risk to business operations. Known increases that are projected to be offset through cost optimization efforts include: (1) merit increase ($.2 million); (2) increase in cloud subscriptions ($1.28 million), as described in detail later in my testimony; (3) decrease in managed services/contractor ($.68 million); and (4) net zero increase in license and maintenance agreements because of cost optimization efforts ($.15 million).

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

A. As described earlier, Operations O&M expense is made up of several components. As shown in the graph below, Operations O&M includes labor, business expenses, material costs, managed services/contractor support, and vendor licensing and maintenance contracts.



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

"Business Expense" includes costs such as: employee training, wireless plans, and supplies. These costs are variable and dependent on needs of the organization.

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

"Managed Services/Contractor" are costs of third parties that maintain and operate the Company's IT assets. Very similar to "Labor," the activities include system monitoring, system break/fix, disaster recovery activities, system analysis, and patching. The use of third parties to maintain and operate the Company's IT assets provides value by helping to control labor costs, offers up to 24/7/365 support, and provides certain types of expertise not resident at the Company.

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

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

Q. Please further describe the make-up of "Cloud Subscriptions" within the Company's IT Operations O&M expenses.

A. "Cloud Subscriptions" contracts include costs for software, platform, and infrastructure as a service. There are several items contributing to the net decrease in cloud subscriptions in 2023, reduction in reporting subscription ($.09 million); reduction related to ESB ($.23 million); reduction related to IT Portfolio Management ($.08 million); reduction related to customer digital experience platform ($.15 million); and increase related to IT Service Management ($.27 million).

The cloud subscriptions increase in 2024 is related to an increase in IT Service Management capabilities ($.17 million); increase in workplace collaboration tools ($.26 million); and migration to the cloud ($.84 million). Cost efficiencies gained from cloud services after implementation are described in the Digital – Hybrid Cloud and Data Center Migration project near the end of the testimony.

The cloud subscriptions increase in 2025 is related to further migration to the cloud ($.34 million) and increase related to records management capabilities ($.08 million).

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

A. Exhibit A-18 (SHB-2) is the Historical 13-month Average of IT Cloud Computing Prepaid Balance for Gas and Common for the actual 13-month balance ending June 30, 2023 and projected 13-months ending September 30, 2025. It provides a summary of the gas allocation of actual and projected IT Department operational expenditures. Specifically:

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

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

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

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

A. Yes, the method used by the Company to project IT Operations O&M expenses in Exhibit A-17 (SHB-1) is the most accurate method. The Company's approach uses a detailed analysis of known fixed and variable expenses for the test year. These include increases that result from new investments and assets tied to growth in digital capabilities outlined in the Digital Plan, new cyber security regulations and requirements, and outcomes of cost optimization efforts. By using known and expected expenses that are coupled with the evolving digital landscape, the projection is the best representation of the Company's required IT Operations O&M expenses in the test year.

<u>INVESTMENTS O&M EXPENSES—MAINTAIN ADEQUATE SYSTEM CURRENCY AND BUILD NEW CAPABILITIES</u>

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

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

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

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

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

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

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

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

Until recently, the Company has not been authorized the full O&M needed in rates to maintain and keep systems current. Technical obsolescence continues to increase, and the Company is in a position of playing catch-up, adding risk that a significant cyber security or technical issue might not be remediated or mitigated, which would cause direct impact to Company operations, its customers, or both. The Company prioritizes operational support over new investments when resources are limited, thus putting the NGDP at risk when important systems cannot be kept current within recovered rates.

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

A. Exhibit A-19 (SHB-3) is a Summary of Actual and Projected IT Investments O&M Expenses for the Years 2022, 2023, 2024, and 12 months ending September 30, 2025. Page 1 provides a summary of the gas allocation of actual and projected IT Department Investments O&M expenditures. Specifically:

- Column (a) provides the Investments O&M expense category;
- Column (b) identifies the 2022 historical Investments O&M expense as $6,869,000;
- Column (c) identifies the 2023 projected Investments O&M expense as $5,042,000;
- Column (d) identifies the 2024 projected Investments O&M expense as $7,197,000;
- Column (e) identifies the three months ending December 31, 2024 projected Investments O&M expense as $1,799,000;
- Column (f) identifies the nine months ending September 30, 2025 projected Investments O&M expense as $4,840,000;
- Column (g) identifies the Test Year projected Investments O&M expense as $6,639,000;
- Column (h) identifies the 2025 projected Investments O&M expense as $6,453,000;
- For Investments Planning expense, "Labor" line items include employee labor, and "Contracts" line items include hardware and software licenses and maintenance, staff augmentation, and other contracted services; and
- For Investments expense, "Labor" line items include employee labor, "Software" line items include software licenses and maintenance contracts, "Material" line items include hardware purchases and maintenance contracts, "Contractor Costs" line items include staff augmentation, managed services, and other contracted services, and "Overhead and Others" line items include overheads and business expenses.

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

- Column (a) is a description of the categorical expense;
- Column (b) provides the historical Investments O&M expense;
- Column (c) provides the historical amount to which an inflation rate or merit increase rate was applied;
- Columns (d), (f), and (h) provide the merit and inflation increases for each respective period;
- Column (e) and (g) provides the amount to which an inflation rate or merit increase rate was applied for each bridge period, respectively;
- Column (i) includes amounts that were projected using other methods; and
- Column (j) provides the projected test year Investments O&M and is the sum of columns (b), (d), (f), (h), and (i).

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

A. IT does not apply inflation for categorical spend projections for Investments Planning expense. The investments planning projection is adjusted by $135,000 for an anticipated decrease in the test year for investments planning activities that directly support business case development and cost estimate refinement for projects that support the Digital Plan, NGDP, and other Company long-term plans. Inflation is also not used to project future Investments O&M expense. The other adjustments for Investments O&M expense of $95,000 are based solely on expected project costs for the test year as compared to the historical period, as detailed in Exhibit A-20 (SHB-5).

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

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

Q. Is the investment planning activity speculative?

A. No, it is not speculative. Investment planning is a pragmatic process that results in documented technology investment details. The process documentation includes: a project description and description of system functionality, project timelines including expected implementation date and spending plans, project benefits, a description of alternatives considered and rationale behind the decision, and cost benefit ratio, which were required by the MPSC in Case No. U-18238. Other important activities of investment planning are: identifying high-level business requirements, determining whether the functionality needed is already present in the Company's IT environment, identifying performance and security requirements, working with software vendors and cloud solution providers to demonstrate the effectiveness and security of their products and services, and developing the business case with project costs and benefits to confirm whether a proposed project should be approved for development and implementation.

During this phase, the Company spends the necessary time on up-front planning and due diligence for the technology investment. As an example, to maintain the reliability and safety of the Company's gas pipeline, the Company needed to replace the gas pipeline corrosion control system. The Company spent time up-front planning for the Corrosion Control Modernization project to build and confirm the scope, estimates, and alternatives. Investment planning is needed to better understand the vendor solution and organize the work. Investment planning is based on key outcomes and fact-gathering to ensure it is not merely speculative.

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

A. Yes, the Company should be allowed recovery for this up-front planning activity. This work is required by the MPSC for technology investment, and for good reason. It is in the best interest of the Company's customers that the Company perform these investment planning activities to ensure potential investments provide sufficient value to justify the expense. The Company considers many ideas, but not all are feasible or even warrant investment planning. Critical as these expenses are, the Company does strive to minimize planning expenses; only those potential investments with the highest expected value even reach the planning phase. This reasonable and prudent work has associated costs and is required by the MPSC for technology investment planning. Accordingly, the Company should receive recovery for this required expense.

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

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

INVESTMENTS CAPITAL EXPENDITURES

Q. Has the Company changed how investments are categorized?

A. Yes, the Company has categorized investments by business category or product lines and no longer will be using programs, such as Enhancements, BP Functionality, IT Service Delivery, etc. that have been used historically. The new business categories or product lines are described later in my testimony.

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

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

- Column (a) provides the business category or product line designation for the capital expenditures:
  - Corporate;
  - Customer;

  - Gas;
  - Electric & Gas Shared; and
  - IT/Digital Foundation;
- Page 1 of 2
  - Column (b) identifies the 2022 historical year capital expenditures as $18,950,000;
  - Column (c) identifies the 12 months ending December 31, 2023 projected bridge year capital expenditures as $23,069,000;
  - Column (d) identifies the 9 months ending September 30, 2024 projected bridge year capital expenditures as $19,709,000;
  - Column (e) identifies the 21 months ending September 30, 2024 projected bridge year capital expenditures as $42,778,000; and
  - Column (f) identifies the 12 months ending September 30, 2025 projected test year capital expenditures of $23,289,000;
- Page 2 of 2
  - Column (b) identifies the 9 months ending September 30, 2023 capital expenditures as $14,006,000;
  - Column (c) identifies the 12 months ending September 30, 2024 capital expenditures as $28,771,000;
  - Column (d) identifies the 12 months ending September 30, 2025 projected bridge year capital expenditures as $23,289,000; and
  - Column (e) identifies the 33 months ending September 30, 2025 projected bridge year capital expenditures as $66,067,000;
- For Investments expenditures, “Labor” line items include employee labor, “Software” line items include software licenses and maintenance contracts, “Material” line items include hardware purchases and maintenance contracts, “Contractor Costs” line items include staff augmentation, managed services, and other contracted services, and “Overhead and Others” line items include overheads and business expenses.

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

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

- Column (a) provides the year of spending for this line item project;
- Column (b) identifies the project name associated with each line item capital expenditure for the applicable year;
- Column (c) identifies the Federal Energy Regulatory Commission ("FERC") category relative to the line item project's asset type;
- Column (d) identifies the Business Category or Product Line of the project which aligns with the financial categorization in the Digital Plan;
- Column (e) provides a synopsis of the project, including the project description and information on project scope, functionality, and benefits;
- Column (f) identifies the project's implementation date;
- Column (g) provides the project's cost/benefit ratio;
- Column (h) provides the total Company expected project capital costs;
- Column (i) provides the total Company expected projected O&M costs;
- Column (j) identifies the project's estimate type;
- Column (k) provides the project's gas portion total capital expenditure for the applicable year;
- Columns (l) through (p) provide the details of categorical spend that sum to the total line item Project Capital Spend for the applicable year broken down by:
    - Software costs (l);
    - Material costs (m);

- Labor costs (n);
- Contractor costs (o); and
- Overhead and other costs (p);

- Column (q) provides the project's gas portion total O&M spend for the applicable year; and
- Columns (r) through (v) provide the details of categorical spend that sum to the total line item Project O&M Spend for the applicable year by the following categories:
  - Software costs (r);
  - Material costs (s);
  - Labor costs (t);
  - Contractor costs (u); and
  - Overhead and other costs (v).

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

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

- Exhibit A-12 (SHB-4), Schedule B-5.1, is a high-level summary of capital expenditures by year, by business category or product line, and by categorical spend; and
- Exhibit A-20 (SHB-5) is a more comprehensive exhibit displaying the detail of each project over the four-year time periods of 2022, 2023, 2024, and 2025.

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

A. Exhibit A-21 (SHB-6) is an Executive Summary report generated from the Company's internal system, BPS. This exhibit provides the approved business case information for each IT project in Exhibit A-20 (SHB-5). Exhibit A-21 (SHB-6) was added to address Commission concerns of:

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

This exhibit provides the same view the Company uses internally to review the Executive Summary of each business case approved to be included in the test year. It also outlines the total Company cost of ownership of each project, including the initial one-time project investment which could include multiple years, and the projected ongoing support costs after project implementation. Additionally, it identifies recurring hard savings over the life of the investment and provides the cost benefit ratio with a zero breakeven point calculated by the Company's internal BPS. Specifically, within each section of this exhibit:

- Header Information section includes project name, the date the report was generated, and BPS identification number. Specifically:
    - Project Name is the name of the project that indicates the project objective;
    - Report Pulled is the date the Executive Summary report was generated from BPS; and
    - Item ID is the unique identifier from BPS.
- Basic Information section includes work category, work type, alias, brief description, portfolio, organization, business unit, and department. Specifically:
    - Work Category identifies classification of work and activities based on the Company methodology;
    - Work Type identifies "project" as the type of work for all IT investments;

  - Alias identifies historical project names for reference;
  - Description identifies a brief description of the project's intent and the expected outcome;
  - Portfolio identifies the financial planning portfolio for whom the work will be performed;
  - Org identifies the financial planning organization for whom the work will be budgeted;
  - Business Unit identifies the business unit for whom the work will be budgeted; and
  - Dept identifies the department for whom the work will be budgeted.
- Work Objectives includes a synopsis of the project, including the problem statement, objectives, information on project scope, functionality, and benefits, and alternatives considered. Specifically:
  - Problem Statement provides an explanation of the problem(s) the work addresses;
  - Objectives provides information about the business value the project will deliver;
  - Scope describes the high-level business functionality and a list of high-level project deliverables; and
  - Alternatives provide a summary of each of the alternatives considered, why each alternative was not selected and the rationale behind the alternative selected.
- Dates section includes the projected implementation phase start or end dates for projects with the exception of the Annual Spend Programs, such as Asset Refresh Programs, Application Currency, and Enhancements. Specifically:
  - Initiation is the start date of the project Plan phase;
  - Project Plan & Scope Definition is the end date of the project Plan phase;
  - Final Engineering, Planning & Design is the end date of the Design phase;
  - Execution is the end date of the Execute phase;

    - In-Service/Go-Live is the project's implementation date; and
    - Closeout is the end date of the Close phase.
- Funding Summary section includes a Total Company summary and detailed breakdown of projected categorical spend by year for each project. Specifically:
    - Summary of the Total Cost of Ownership of projected capital expenditures and O&M expense for each project, including ongoing maintenance, where:
        - Cap+COR is the total of all the capital expenditures; and
        - O&M is the total of all the O&M expense for the project implementation and ongoing maintenance.
    - Total Project Cost contains a detailed categorical breakdown for projected capital expenditures and O&M expense for each project, excluding ongoing maintenance, where:
        - Staffing includes the internal labor costs for project implementation;
        - Outside Services includes the external labor and services for project implementation;
        - Business Expenses/Overheads includes costs for items such as training, travel, lodging, and meals and Loadings & Allocations for Corporate Overheads and Allowance for Funds Used During Construction ("AFUDC");
        - Employee Benefits includes costs for employee benefits;
        - Material includes costs for hardware purchases;
        - Licenses, Permits & Fees includes costs for software and hardware licenses and maintenance; and
        - Other includes miscellaneous costs.
- Value & Impacts Summary Section provides a summary of the projected cost and benefits, risk and other value associated with a project for Capital expenditures and O&M expense, including ongoing maintenance, where:
    - For purposes of O&M:
        - Reduction includes the hard O&M savings;

    - Initial includes the implementation and ongoing maintenance costs;
    - Incremental includes any other O&M costs; and
    - Net is the difference of the reduction, initial, and incremental O&M costs.

- For purposes of Cap+COR:
    - Reduction includes any hard capital savings;
    - Initial includes the implementation costs;
    - Incremental includes any other capital costs; and
    - Net is the difference of the reduction, initial, and incremental capital costs.

- For purposes of Revenue:
    - Reduction includes any expenses;
    - Initial includes implementation revenue;
    - Incremental includes any increase in revenue; and
    - Net is the difference of the reduction, initial, and incremental revenue.

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

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

Where
B = Benefits
C = Total Costs

- For purposes of identifying risk:
    - Type of Corporate Risk;

    - Level of impact;
    - Likelihood of risk; and
    - Description of risk.
  - And, for purposes of identifying other value:
    - Type of other value; and
    - Description of other value.

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

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

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

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

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

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

INVESTMENT IDENTIFICATION, PRIORITIZATION, APPROVAL, AND PROJECT PLANNING

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

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

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

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

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

Q. Are ROM estimates akin to contingency as indicated by the Commission on page 128 of its December 22, 2021 Order in Case No. U-20963 ("U-20963 Order")?

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

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

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

Year	Projected	Adjusted Projected (20% ROM Adjustment)
2022	$18,949,780	$18,949,780
2023	$24,185,466	$23,069,101
2024	$28,863,119	$26,278,309
2025	$25,122,871	$22,293,001
Test Year	$26,057,933	$23,289,328

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

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

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

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

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

<u>INVESTMENT PROJECTS</u>

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

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

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

- **Customer** projects that are necessary to enable the Company to comply with regulatory billing changes, improve billing functionality, improve customer satisfaction, increase the Company's ability to serve customers within the channel of their choice, and engage customers to enroll in demand response and energy waste reduction programs;

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

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

IT Projects Enabling Other Areas

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

A. Below are the projects enabling NGDP. As described in Exhibit A-26 (SHB-11), in the Business Drivers\Gas and Business Drivers\Work Management Common to Electric and Gas sections, investments in digital capabilities are essential to achieving the Company's NGDP business plan and Work Management improvements. A synopsis of each project with its value is included in the testimony of other Company witnesses, as indicated below.

Project	Projected Test Year Capital	ROM Adjusted Test Year Capital	Test Year O&M	Witness
Field Contractor Work Management Technology Enablement	$168,549	$0	$1,146	James P. Pnacek
Field Supervisor Automation	$145,301	$116,240	$18,558	James P. Pnacek
Gas Customer Appointment Booking	$904,870	$723,896	$107,917	James P. Pnacek
Work Management Scheduling Analytics and Reporting	$122,785	$0	$2,843	James P. Pnacek
Gas Leak Asset and Work Management	$383,129	$306,503	$40,527	Lincoln D. Warriner
Gas Nominations Replacement Solution	$816,330	$653,064	$134,758	Lincoln D. Warriner
Gas SCADA Software Solution	$3,641,196	$2,912,956	$479,854	Lincoln D. Warriner
Gas T&D Historian	$296,002	$236,802	$56,850	Lincoln D. Warriner
Gas Compression Digital Work Management	$230,783	$184,626	$16,050	Timothy K. Joyce
Gas Compression Historian	$1,661,063	$1,328,850	$133,207	Timothy K. Joyce
Gas Compression Probabilistic Risk Model	$1,182,263	$945,810	$121,875	Timothy K. Joyce
Gas Storage Probabilistic Risk Model	$129,225	$0	$40,088	Timothy K. Joyce

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

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

A. Below are projects included within the Customer area. As described in the Digital Plan, Exhibit A-26 (SHB-11), the Business Drivers\Customer section provides how digital investments support lower cost of customer service, increase customer engagement and enrollment in programs, and increase use of digital platforms. A synopsis of each project with its value is included in the direct testimony of Company witness Steven Q. McLean:

Project	Projected Test Year Capital	ROM Adjusted Test Year Capital	O&M
Customer Order Service Tracker	$856,507	$685,206	$178,155
Customer Work Request Web Portal	$435,932	$348,746	$119,542

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

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

A. Below are projects included within the Corporate area. As described in the Digital Plan, Exhibit A-26 (SHB-11), the Business Drivers\Corporate section provides the areas of core shared services and key capabilities needed to operate the utility and how the use of digital solutions can optimize and even transform these foundational services. A synopsis of each project with its value is included in the direct testimony of Company witness Matthew J. Foster:

Project	Projected Test Year Capital	ROM Adjusted Test Year Capital	Test Year O&M
Expense Reporting Improvements	$134,162	$107,330	$38,961
Talent Management Enablement	$164,456	$131,565	$35,996
Enterprise Risk Management	$0	$0	$7,139

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

IT/Digital Foundations and Capabilities

ARP

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

A. The Company's ARP projects replace technology assets in line with industry and Company life-cycle expectations for the specific assets in each type of program. Replaced assets are recycled, donated, or sold if there is residual value. The Company's research shows that industry standards on refreshing hardware are generally three to five years, although the Company refreshes monitors every eight years based on Company data related to historical failure rates. Refreshing hardware at the recommended cycle allows the Company to: (1) reduce security risks and help ensure devices are updated and patched to avoid vulnerabilities; (2) avoid costs due to increasing hardware failures; (3) avoid frustration for its customers and lost productivity for its employees due to downtime; (4) receive continued operating system support as older versions are retired by the manufacturer; and (5) ensure employees have the required hardware to support their work.

Below are links to some of the industry standards the Company has reviewed to determine its hardware refresh time periods:

- Michigan.gov, Information Technology Equipment Life Cycle. https://www.michigan.gov/documents/dtmb/Sec._829_IT_Lifecycle_Report_FY_2021_717757_7.pdf
- International Data Corporation ("IDC"), Why Upgrade Your Server Infrastructure Now? (IDC is a global provider of market intelligence, advisory services, and events for the information technology, telecommunications, and consumer technology markets.)https://www.dell.com/learn/us/en/12/shared-content~data-sheets~en/documents~dell_why_upgrade_incl_link_to_dell.pdf

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

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

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

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

A. The following are the ARP and infrastructure projects:

- The **ARP-Collaboration** project requires $395,184 in capital and $82,244 in O&M in the test year.
    - **Description:** This project will replace the Company's obsolete or out-of date audio, visual, telephony and other communication collaborative tools and equipment.
    - **Problem Statement:** When Collaboration Assets that are used to support customer interactions and business operations are obsolete or out-of-date, they can be more difficult to keep current with Security updates. The Company also runs the risk of failure of these assets if it does not adhere to a regular refresh cycle.
    - **Objectives:** This project creates value by: (1) ensuring that the Company's audio, visual, telephony, and other communications systems are stable and reliable; and (2) retiring the legacy enterprise Avaya telephone systems that have reached end of mainstream manufacturer support.

- **Scope:** The project scope consists of: (1) annually replacing aging collaboration assets; and (2) installing new collaboration assets to account for evolving business requirements.

- **Alternatives:** The following alternatives were considered: (1) refresh visual assets and a portion of the audio assets; (2) refresh a portion of the audio assets only; and (3) refresh visual assets only. These alternatives were not chosen due to the risk inherent with a partial replacement of assets, which includes: (1) a reduced supply of equivalent replacement Avaya parts that are no longer being produced; and (2) an erosion of the knowledge technicians possess on discontinued systems.

- The **ARP-Field Device Asset Management ("FDAM")** project requires $1,474,358 in capital and $1,980 in O&M in the test year.

  - **Description:** This project will replace field devices according to a four-year refresh cycle that is based on industry standards, hardware failures, security patches, and software compatibility.

  - **Problem Statement:** When Field Device Assets used to support customer interactions and business operations are obsolete or out-of-date, they are more expensive to support and keep current with Security updates as equipment becomes obsolete. The Company also runs the risk of failure of these assets if it does not adhere to a regular four-year refresh cycle.

  - **Objectives:** This project creates value for the Company by: (1) improving stability and availability of business-critical applications by proactively replacing field devices prior to increasing hardware failures; and (2) allowing field workers to complete their job tasks.

  - **Scope:** The project scope consists of replacing field device assets according to the four-year refresh cycle.

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

- The **ARP-Infoblox Refresh** project requires $340,345 in capital and $14,846 in O&M in the test year.

- **Description:** The ARP-Infoblox Refresh project will replace the Company's Infoblox system.

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

- **Objectives:** The value of this program includes: (1) enabling the Company to efficiently manage and control their networks; and (2) providing Domain Name System ("DNS"), Dynamic Host Configuration Protocol ("DHCP"), and Internet Protocol Address Management ("IPAM").

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

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

- The **ARP-LAN** project requires $597,392 in capital and $20,669 in O&M in the test year.

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

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

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

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

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

Q. What were the total project actuals and projected capital expenditures of the ARP-LAN project in Case No. U-21148?

A. The Case No. U-21148 projected capital expenditures by cost category for the ARP-LAN project are in the table provided below.

ARP-Local Area Network			
Case No. U-21148			
Cost Category	**Total Company**	**Gas Allocation**	
	Capital	**Capital**	**U-21148 Reference**
2021 Projected			
Software	$0	$0	A-131 (DDP-7) line 157, column j
Material	$3,568,846	$1,497,488	A-131 (DDP-7) line 157, column k
Labor	$71,500	$30,001	A-131 (DDP-7) line 157, column l
Contractor Costs	$0	$0	A-131 (DDP-7) line 157, column m
Overhead & Other Costs	$7,150	$3,000	A-131 (DDP-7) line 157, column n
Total 2021 Projected	**$3,647,496**	**$1,530,489**	A-131 (DDP-7) line 157, column i
2022 Projected			
Software	$0	$0	A-131 (DDP-7) line 243, column j
Material	$1,455,831	$610,867	A-131 (DDP-7) line 243, column k
Labor	$145,530	$61,064	A-131 (DDP-7) line 243, column l
Contractor Costs	$122,100	$51,233	A-131 (DDP-7) line 243, column m

Overhead & Other Costs	$69,106	$30,658	A-131 (DDP-7) line 243, column n
Total 2022 Projected	**$1,796,527**	**$753,823**	A-131 (DDP-7) line 243, column i
Total Projected			
Software	$0	$0	
Material	$5,024,677	$2,108,355	
Labor	$217,030	$91,065	
Contractor Costs	$122,100	$51,233	
Overhead & Other Costs	$80,216	$33,658	
Total Actuals/Projected	**$5,444,023**	**$2,284,312**	

1 **Q. What are the current total project projected capital expenditures for the ARP-LAN**
2 **project in Case No. U-21490?**
3 A. The Case No. U-21490 total actual and projected capital expenditures by cost category for
4 the ARP-LAN project are in the table provided below.

ARP-Local Area Network			
Case No. U-21148/U-21490			
Cost Category	**Total Company Capital**	**Electric Allocation Capital**	**Reference**
2021 Actuals			
Software	$0	$0	A-21 (SHB-6) line 81, column k
Material	$181,434	$76,130	A-21 (SHB-6) line 81, column l
Labor	$13,896	$5,831	A-21 (SHB-6) line 81, column m
Contractor Costs	$141	$59	A-21 (SHB-6) line 81, column n
Overhead & Other Costs	$1,666	$699	A-21 (SHB-6) line 81, column 0
Total 2021 Actuals	**$197,137**	**$82,719**	A-21 (SHB-6) line 81, column j
2022 Actuals			
Software	$14,741	$6,185	A-20 (SHB-5) line 64, column l
Material	$91,998	$38,603	A-20 (SHB-5) line 64, column m
Labor	$40,630	$17,048	A-20 (SHB-5) line 64, column n
Contractor Costs	$180,643	$75,798	A-20 (SHB-5) line 64, column o
Overhead & Other Costs	$14,182	$5,951	A-20 (SHB-5) line 64, column p
Total 2022 Actuals	**$342,193**	**$143,584**	A-20 (SHB-5) line 64, column k
2023 Projected			
Software	$12,668	$5,564	A-20 (SHB-5) line 177, column l

Material	$4,369,664	$1,919,157	A-20 (SHB-5) line 177, column m
Labor	$314,800	$138,260	A-20 (SHB-5) line 177, column n
Contractor Costs	$166,724	$73,225	A-20 (SHB-5) line 177, column o
Overhead & Other Costs	$64,524	$28,339	A-20 (SHB-5) line 177, column p
Total 2023 Projected	**$4,928,380**	**$2,164,544**	A-20 (SHB-5) line 177, column k
2024 Projected			
Software	$0	$0	A-20 (SHB-5) line 254, column l
Material	$3,524,512	$1,635,021	A-20 (SHB-5) line 254, column m
Labor	$363,656	$168,700	A-20 (SHB-5) line 254, column n
Contractor Costs	$122,100	$56,642	A-20 (SHB-5) line 254, column o
Overhead & Other Costs	$179,465	$83,254	A-20 (SHB-5) line 254, column p
Total 2024 Projected	**$4,189,733**	**$1,943,617**	A-20 (SHB-5) line 254, column k
2025 Projected			
Software	$0	$0	A-20 (SHB-5) line 324, column l
Material	$225,000	$104,378	A-20 (SHB-5) line 324, column m
Labor	$50,000	$23,195	A-20 (SHB-5) line 324, column n
Contractor Costs	$20,500	$9,510	A-20 (SHB-5) line 324, column o
Overhead & Other Costs	$24,935	$11,567	A-20 (SHB-5) line 324, column p
Total 2025 Projected	**$320,435**	**$148,650**	A-20 (SHB-5) line 324, column k
Total Projected			
Software	$27,409	$11,749	
Material	$8,392,608	$3,773,289	
Labor	$782,982	$353,034	
Contractor Costs	$490,108	$215,234	
Overhead & Other Costs	$284,772	$129,810	
Total Actuals/Projected	**$9,977,879**	**$4,483,116**	

Q. Why have the total project actuals and projected capital expenditures of the ARP-LAN project changed from projections presented in Case No. U-21148?

A. The total project actuals and projected capital expenditures of the ARP-LAN project in this Case No. U-21490 changed from projections in Case No. U-21148 due to supply chain shortages in 2021 and 2022 and end of support of the Company's current model of the hardware of June 30, 2024. The supply chain shortages resulted in deferring some planned spend for 2021 and 2022 into 2023 and 2024. Additionally, the end of support of the current model of the hardware significantly increased the number of units that needed to be replaced increasing costs in 2023 and 2024. If this hardware is not refreshed by end of support, the vendor will no longer provide maintenance releases and patching; creating risk for the Company's critical systems that support critical business operations.

- The **ARP-OT Support Gas** project requires $948,614 in capital and $114,585 in O&M in the test year.
  - **Description:** The ARP-OT Support Gas project will replace dated and obsolete servers on a rotating 5 year refresh schedule.
  - **Problem Statement:** When OT Assets that are used to support customer interactions and ensure the stability of technology for business operations are obsolete or out-of-date, they are more expensive to support and can be more difficult to keep current with Security updates. The Company also runs the risk of failure of these assets if it does not adhere to a regular refresh cycle.
  - **Objectives:** This project creates value by maintaining the currency of the Company's IT infrastructure and the core enterprise software that are utilized to support the operation of the Company's critical gas infrastructure.
  - **Scope:** The program scope consists of: (1) replacement of computer hardware under the program; and (2) installing additional new compute capacity to account for expanding business requirements.
  - **Alternatives:** The alternatives considered include: (1) continue to operate hardware beyond a five- to seven-year refresh cycle, or (2) refresh hardware based on a five- to seven-year refresh cycle along with evaluating the health of the asset and evolving business needs. The alternative to operate hardware beyond a five- to seven-year refresh cycle was not selected due to the risk that these hardware component failures would cause system reliability and safety for customers, as vendors do not provide extended support after seven years. The Company chose the alternative to refresh this hardware based on a five- to seven-year refresh cycle along with evaluating the health of the asset and evolving business needs to reduce the risk of impacting critical infrastructure that supports systems such as Gas SCADA and Gas Compression control systems.
- The **ARP-Printer Asset Management ("PAM")** project requires $252,225 in capital and $1,850 in O&M in the test year.
  - **Description:** This project will replace and install select printers, plotters, and multi-function printing devices based on printer replacement assessments and a five-year refresh cycle. Printer service and usage history is evaluated and a determination is made if a printer can be repurposed instead of ordering a new one.

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

- **Objectives:** This project creates value for the Company by: (1) improving the dependability of these printer devices for employees; (2) averting increased costs due to hardware repairs; and (3) ensuring compatibility with enterprise print applications.

- **Scope:** The project scope consists of the annual replacement of printer assets according to a five-year refresh cycle.

- **Alternatives:** The alternatives considered for the project included looking at refresh cycles from three to seven years as well as running the assets to failure. The selection of a five-year cycle was deemed to be the best solution since anything less than five years would increase the likelihood of unneeded expense for replacement of assets that were still in good operating condition. Anything greater than five years is assessed monthly to ensure it is not run-to-failure, including running the asset to failure, resulting in additional expenses for maintenance of the equipment and downtime, negatively affecting employee productivity. The Company assesses the printer fleet based on years of active service, service history, printer usage data, and the number of users within a facility. Based on these factors, the Company either decommissions, repurposes, leaves in place, or refreshes the printers.

- The **ARP-Radio** project requires $1,528,365 in capital and $78,702 in O&M in the test year.

  - **Description:** This project will refresh hardware to include; 800Mhz Radios and infrastructure, cellular modems, plant radios and systems, cellular amplification devices and vehicle consoles in service trucks. This equipment supports mission critical voice and data communications for plant and field service personnel and dispatch personnel. 800MHz radios are upgraded on a 10-year lifecycle basis. Plant radio systems are upgraded on a scheduled 7-year lifecycle basis. Cellular modems are refreshed on a 5-year life cycle basis. Amplification systems are refreshed on a 10-year life cycle.

  - **Problem Statement:** Vehicle consoles are typically retired with the vehicle but are salvaged for reuse in new vehicles when possible. 800MHz, mobile, and portable radios, Plant radios systems, and Cellular modems support core business functions, life safety communications, and rapid response for restoration of customers service and critical infrastructure. Company radio systems must be refreshed on a scheduled basis or risk exceeding life expectancy and failing. The refresh of these subscriber units in a proactive manner is critical to providing service to customers. If these units are not refreshed, the increased risk of unit failure would result in interruptions to timely and concise communications to field personnel to resolve gas leaks, and downed electric lines, or service turn-on requests, which risks life safety.

- **Objectives:** This project creates value for customers and the Company by: (1) upholding public safety; (2) ensuring timely responses and repairs to emergent gas leaks, wire downs, and electric outages; (3) ensuring real-time communications between Company dispatch locations and crews in the field; (4) ensuring the safety of personnel working in higher risk workspaces by replacing equipment with units that contain intrinsically safe batteries; (5) supporting continuous improvement and training by replacing equipment that is capable of capturing audio recordings; and (6) remaining in compliance with MPSC regulatory requirements by maintaining critical radio infrastructure.

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

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

- The **ARP-Server and Storage** project requires \$565,283 in capital and \$49,982 in O&M in the test year.

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

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

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

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

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

Q. Please explain the ARP-WAM project.

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

- The **ARP- WAM** project requires $2,590,393 in capital and $12,471 in O&M in the test year.

  - **Description:** This project will replace and install new desktops, laptops, and tablets on a four-year refresh cycle based on industry standards, hardware failures, security patches, and software compatibility. Monitors will be replaced every eight years based on Company data related to historical failure rates.

  - **Problem Statement:** When Workstation Assets that are used to support customer interactions and business operations are obsolete or out-of-date, they are more expensive to support and keep current with security updates as equipment becomes obsolete. The Company also runs the risk of failure of these assets if it does not adhere to a regular refresh cycle.

  - **Objectives:** This project creates value for the Company by: (1) improving stability and availability of business-critical applications by proactively replacing workstations prior to increasing hardware failures; and (2) allowing business partners to complete their job tasks.

  - **Scope:** The project scope consists of: (1) replacing workstation assets; and (2) installing new units for new resources.

  - **Alternatives:** The alternatives considered were to: (1) extend the replacement cycle from four years to five years for all desktops and laptops; (2) extend the replacement cycle only on desktops from four years to five years; and (3) use outdated equipment. The Company did not select these options because: (1) there would be an increased risk of hardware failure and equipment outages that could impact the capacity of business partners to complete job tasks; (2) it could cause applications to run poorly or stop functioning; (3) it would increase the ARP in future years based on the number of devices that were not replaced during the four year refresh cycle; and (4) it could cause an inability to apply security patches.

Based on industry data, waiting longer than the four-year cycle would increase hardware failures, security patch issues, and software compatibility concerns, resulting in additional downtime that could affect customer safety and storm restoration. The Company selected a four-year refresh cycle for desktops, laptops, and tablets; and an eight-year cycle for monitors to alleviate these concerns.

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

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

- These references reinforce replacing PCs at four years or less:
    - Michigan.gov, Information Technology Equipment Life Cycle. https://www.michigan.gov/documents/dtmb/Sec._829_IT_Lifecycle_Report_FY_2021_717757_7.pdf
    - https://i.crn.com/sites/default/files/ckfinderimages/userfiles/images/crn/custom/INTELBCCSITENEW/WhitePaper_EnterpriseRefresh.pdf
- Data from the Company's internal incident tracking system indicates that the 420 PC and field device workstation assets that are four plus years of age had 731 incidents resulting in lost productivity and added expense to repair or replace the assets.
- The vendor's three-year warranty duration for Company PCs combined with the incident history reinforce four years is the optimum time for replacement.

The labor cost of addressing incidents and lost productivity, the warranty period, the internal incident data and external references confirm PC and field device replacement on a four-year cycle. Similarly, Company historical failure rates for monitors indicate an eight-year cycle as ideal, which is what the Company employs for monitors.

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

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

- **Replacements:**
  - Are determined by pulling the quantity of device types with a scheduled retirement year:
    - PC device's scheduled retirement year is four years from purchase, and
    - Monitor's scheduled retirement year is eight years from purchase;
  - The model of device determines the unit cost. The total of these devices with their current unit cost is established for a particular year's budget;
  - Accessories for PC devices are included in the device unit cost projections including keyboards, surge protectors, docks, backpacks, and cables; and
  - Carryover devices are added from the previous year to address aging devices first.
- **New Purchases:**
  - Are determined based on People and Culture hiring estimations and any known PC device needs of a particular work group (e.g. some engineering groups require high performance devices);
  - Associated new monitors to go along with the PC devices are identified;
  - The model of device and monitor determines the unit cost;
  - Accessories for PC devices are included in the device unit cost projections; and
  - Unique situations have come up requiring incremental new purchases such as post-pandemic return to work changes that have required incremental purchases of monitors to meet CDC guidelines.

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

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

A. Variances for the ARP-WAM project are a result of changes to scheduled replacements per four-year PC device and eight-year monitor refresh cycles, previous year deferrals for equipment replacements primarily due to working around the pandemic impacts, and incremental unit cost increases. Exhibit A-22 (SHB-7), page 9, details the devices, number of units, and unit costs for each type of device. Below are summary charts with the variance reasons for each year separated between replacement and new purchase categories.

Replacements

Year	PC Device	Monitor	Reason for variance
2022 Actual	1,611	1,057	• Monitor replacements associated with 452 PC devices that were deferred to 2022 from 2021 due to supply chain issues with hardware vendors. • Actual for 2022 decreased based on disallowances in U-20963 and 296 PC devices moved to 2023.
2023 Plan	3,044 (2,748 +296 carryover)	0	• 296 PC devices that could not be replaced due to disallowances were deferred to 2023. • No monitor replacements costs have been projected for 2023, although there will likely be some monitor replacements associated with the 296 PC devices that were deferred to 2023.
2024 Plan	2,766	0	No monitor replacements planned since monitors' eight-year replacement cycle was completed 2018-2021. The next monitor replacement is targeted to resume in 2026.
2025 Plan	3,419	0	No monitor replacements planned since monitors' eight-year replacement cycle was completed 2018-2021. The next monitor replacement is targeted to resume in 2026.

New Purchases

Year	PC Device	Monitor	Reason for variance
2022 Actual	632	1,004	• Increased PC purchases based on actual new employee volume. • Increased monitor purchases for the return to facilities. This purchase allowed resources to adhere to CDC guidelines for in-person work.
2023 Plan	224	150	Projection for 2023 decreased based on actual hiring.
2024 Plan	445	365	Projection for 2024 based on People and Culture estimated hiring.
2025 Plan	445	365	Projection for 2025 based on People and Culture estimated hiring.

Q. Do the Company's 2023 projected gas allocation capital expenditures for the ARP-WAM project differ from the $2,930,189 projected in Case No. U-21308?

A. Yes. The 2023 projected gas allocation capital expenditures for the ARP-WAM project of $2,288,589 are $641,600 less than the $2,930,189 projected in Case No. U-21308.

Q. Is the $641,600 difference in the Company's 2023 projected gas allocation capital expenditures from the amount projected in Case No. U-21308 for the ARP-WAM project explainable?

A. Yes. The difference in 2023 projected gas allocation capital expenditures of $641,600 for the ARP-WAM project from the amount projected in Case No. U-21308 is explainable. The following describes the difference:

1. Desktops replacements decreased by $.29 million;
2. Laptop and rugged device replacements increased by .47 million; and
3. New PC purchases decreased by $.81 million based on actual hiring.

Upgrades, Replacements, and Application Currency Projects

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

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

Q. Please explain the Upgrades and Replacements projects.

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

- The **Asset Accounting Upgrade 2025-2027** project requires $334,563 in capital and $57,707 in O&M in the test year.

- **Description:** The project will upgrade our current accounting asset management software to the latest version as required by the vendor and implement additional new features, ensuring continued support of a critical financial application, and providing new functionality.

- **Problem Statement:** In 2027, standard vendor support ends for the current on-premise software. Losing vendor support creates security and stability risk that can result in performance issues. When the application is out of the normal support with the vendor, the Company no longer receives security patches, support for defect resolution or bug fixes, and cannot enhance the application. To ensure compliance with regulated and financial accounting in the fixed asset sub-ledger, it is necessary to perform an upgrade and maintain vendor support. In addition, the upgrade provides additional functionality to increase the frequency of financial reporting and improve visibility.

- **Objectives:** This project creates value for the Company by ensuring compliance with regulated and financial accounting within the fixed asset sub-ledger. In addition, the project adds value by: (1) performing the allocation process on a more frequent basis providing better financial visibility; (2) automating manual tasks; and (3) reducing security, stability, and performance risk by ensuring consistent, seamless vendor support.

- **Scope:** The project scope includes: (1) evaluating current vendor/product solution with market leaders; (2) upgrading the vendor software from the current version to the newer version.

- **Alternatives:** Alternatives considered include: (1) Evaluate SAP options for leasing, asset, and tax management capabilities. While this option would eliminate the need for an interface between SAP and PowerPlan, it would be more complex, cost more, and not provide all the required features. (2) Evaluate other software options. This option will introduce new ongoing support costs and integrations and may not provide regulatory reporting and other needed improvements. (3) Upgrade to the newest version of current solution. This is the preferred option as it will reduce hardware and server support costs, provide more frequent software upgrades, avoid database and server upgrades, provide weekly allocation functionality, and provide new features in job scheduling, regulatory reporting for Cost of Service, reporting, and centralized error processing.

- The **AxWay Secure Transport 2024 Upgrade** project requires $28,083 in capital and $22,269 in O&M in the test year.

  - **Description:** Axway SecureTransport is the Company's multi-protocol Managed File Transfer ("MFT") gateway for securing, managing, and tracking data file flow for our business partners and external vendors. Files impacting billing, HR, Supply Chain, Finance, Alternate Energy Programs, Front Office, Back Office, Device Management, Outage Management and Business Reporting functions utilize these services. This project will update the platform to the current software version, enabling cost saving operational enhancements while retaining data security and platform supportability.

- **Problem Statement:** As Axway Secure Transport is the public-facing MFT gateway, maintaining platform version integrity is critical to ensuring it remains secure and supportable in the event of a cyber attack, outage or other critical incident. A prolonged outage or incident, for any reason, compromises the ability of the Company to perform mission-critical business transactions in finance, operations and direct customer support. Upgrading this application also gives the Company the opportunity to properly scale SecureTransport and take advantage of the growing demand for additional, cost-savings features of the tool, such as managing internal Electronic Data Interchange transactions.

- **Objectives:** The value this project brings Consumers Energy and customers includes: (1) Addressing known problems and limitations of the current software and hardware platforms. (2) Ensuring continued secure, scalable, and critical data transmission services running through Axway continue functioning. (3) Creating the capacity to methodically merge/streamline internal and external data file transfer services to eliminate waste. (4) Merging/streamlining the company data file transfer services reducing cyber-attack vectors and creates a more easily maintained and monitored security model.

- **Scope:** The scope of this project includes (1) Upgrading the application and database to the current released and supported versions. (2) Refreshing the underlying application infrastructure by upgrading to the latest operating system and hardware platforms. (3) Enable and test expanded Electronic Data Interchange ("EDI") functionality.

- **Alternatives:** Alternatives considered include: (1) deferring the upgrade. This alternative was not selected because the Axway SecureTransport platform handles critical Company financial, HR and operational transactions--the risk associated with problems stemming from an outdated and unsupported version is too high. Nor would the waste elimination benefits of using the upgraded Axway platform to start consolidating EDI for CE be realized. (2) Replacing the platform. The estimated project costs and timetable for replacing the business functions currently performed by the existing Axway SecureTransport platform would be extensive, and operationally, it is not well suited for a cloud or hybrid cloud solution. In addition to significant platform, application, implementation and functional testing costs, replacing it would require extensive coordination and testing with all of the internal and external account holders, taking upwards of one calendar year. (3) Upgrading the platform. This provides the Company the most cost-effective alternative, balancing costs, known risks, and even growing business capacity and productivity.

- The **Energy Assistance Enhancements and Maintenance Annual Updates** project requires $120,767 in O&M in the test year.

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

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

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

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

  - **Alternatives:** Alternatives considered included: (1) continue with current process, which would lead to loss of grant funding, thus decreasing or eliminating energy assistance dollars for customers; (2) transfer administration of Energy Assistance Programs to a third party organization, which would remove ownership and visibility into the health of the program while increasing administrative costs; and (3) make annual updates to the application, which will allow agencies to easily enroll customers on assistance programs and allow placement of holds to stop or prolong credit activity until assistance decisions are granted. Option 3 was selected since it provides long-term proactive energy assistance to customers and prevents loss of grant funds. Changes are required to internal systems (SAP, Agency Portal, etc.) , therefore a cloud or third party alternative is not viable. Additionally, retiring the existing Agency Portal for a new application would increase costs beyond that of the routine upgrades.

- The **ESB Application 2024-2025 Upgrade** project requires $246,348 in O&M in the test year.
  - **Description:** This project will upgrade and migrate the Business Works developer application to the next version.
  - **Problem Statement:** Newer ESB software versions offer improved integration with Rest/API services and applications. It is critical that this vital data tool or pathway, be more scalable, secure, and capable of integrating to a service-based environment. In addition, the messaging and event modules within the ESB are currently outside of their standard support windows. While it is possible to continue to get extended support by paying an estimated premium of approximately $80,000 annually, this is just temporary coverage and serves only to delay the need for an upgrade.
  - **Objectives:** The value this project provides the Company includes: (1) cost avoidance to avoid extensive payments for extend support purposes; (2) avoid technical obsolescence; (3) operational resiliency; and (4) improved administrative and operational efficiencies.
  - **Scope:** The project scope includes implementing the current version of all applications that are part of the ESB application, database version, and required database drivers.
  - **Alternatives:** Alternatives considered included: (1) Accept the annual $80,000 extended maintenance cost. Given the critical nature of this application, it is not recommended to lose mainstream support for any of the applications involved. Any sustained ESB product deficiency would impact many areas of the Company, such as billing, revenue collection, and remote meter management. The current implementation of the ESB platform was built with five years of growth in mind. This alternative was not chosen due to risk to Company operations and the additional expense. (2) Replace the on-premise upgrade plan to implement a cloud-based solution. A cloud migration would also take longer to complete, which would put the Company at risk of falling outside of the current vendor support window for the products current version. (3) Upgrade the existing application. This option was selected because it best meets the Company needs for the near future by restoring vendor support for fixes and patches, and enables product scalability to the measure required of business capabilities.

- The **HR Support Pack and Business Software Inc (“BSI”) Upgrade 2024 and 2025** projects require in the following O&M in the test year.

Project Year	Test Year O&M
2024	$32,892
2025	$240,924

  - **Description:** The HR Support Pack and BSI upgrade will update the SAP system with HR Support Packs that are released annually by SAP to comply with HR and tax changes.
  - **Problem Statement:** SAP releases annual HR support packs to ensure compliance. Without them, the Company would be unable to comply with HR and tax changes, resulting in the inability to calculate and distribute payroll.
  - **Objectives:** This project creates value for the Company by: (1) ensuring that its systems are in compliance with new financial rules and regulations; and (2) ensuring that it can calculate and distribute payroll.
  - **Scope:** The scope of this project is to add SAP HR corrections to ensure proper reporting of financial information by the Company.
  - **Alternatives:** As this is an upgrade of an existing system, the alternative considered was to delay the upgrade. This alternative was not chosen due to the risk of not complying with financial rules and regulations.

- The **Itron Enterprise Edition (“IEE”) 2024 Upgrade** project requires $29,060 in capital and $45,813 in O&M in the test year.
  - **Description:** This project will upgrade IEE, which collects the reads from meters to ensure accurate and non-estimated bills are provided to customers.
  - **Problem Statement:** IEE is the Company’s keystone application of the Advanced Metering Infrastructure, enabling Time Of Use billing. If this application does not stay current, the Company increases the risk business operations could be interrupted or compromised. Keeping current will also assist the Company in maintaining system capacity, stability, and security obligations with the IEE platform.
  - **Objectives:** This project creates value for the Company by: (1) ensuring the features and functionality needed to meet business requirements are available to business partners and IT; (2) meeting Information Security requirement to keep applications patched and protected from cyber attack; and (3) allowing for validation, estimation, and editing functions for all data collected to ensure accurate billing.
  - **Scope:** The scope of this project includes: (1) upgrading the IEE applications to the next appropriate versions;

- **Alternatives:** Alternatives considered included: (1) Defer the upgrade. This alternative was not selected because it would add application stability, security and dependency risks to the meter data management utility, possibly negatively impacting critical customer electric and gas billing operations. It would also likely de-couple Itron IEE and Meter Data Management from the Itron security infrastructure that other business critical Itron applications use, creating more expense and complexity in the technology environment. (2) Replace the platform. Replacing IEE/MDM would require the application business owners to undertake a new initiative mirroring the expense and effort that went into the multi-million dollar project responsible for setting up and leveraging this utility. (3) Perform the upgrade. This option best suits customer and Company needs as it restores vendor support for hot fixes and patches as well as keeping IEE integrated into the Itron Security infrastructure with the other Itron software products in use at the Company, like Itron Field Collection Systems.

- The **Public Key Infrastructure ("PKI") Upgrade** project requires $29,365 in capital and $14,291 in O&M in the test year.

  - **Description:** Replace on-premise PKI to stay supported by the manufacturer.

  - **Problem Statement:** The existing PKI that issues certificates to IT systems for secure communications needs to be upgraded to stay supported by the manufacturer. If the PKI is not maintained, in the event of a system failure the Company would not have support in recovering. All IT systems requiring secure communications via certificates would go offline within three days.

  - **Objectives:** Replace existing PKI with new PKI that is supported by the manufacturer.

  - **Scope:** The project will build and configure the servers necessary to provide PKI services, put in place physical token management for maintaining security, migrate certificate issuing and management to the new system and decommission the old system.

  - **Alternatives:** The Company has a limited use service for PKI on the Internet only. (1) The Company looked into expanding the service to include usage on the Company network but found the solution to not be economically viable. (2) The Company also looked at full cloud solutions, but it did not meet the security standards currently being used around physical token use. (3) The Company looked at continuing extended support, however the continuing extended support is not available by the vendor. (4) The Company selected a hybrid solution of part cloud and part on-premise to meet all operational and security compliance requirements. The opportunity is to retain ownership of the keys on-premise prior to evaluating ownership through the cloud.

- The **SAP Support Pack Upgrade 2023-2024** project requires $110,766 in O&M in the test year.

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

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

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

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

  - **Alternatives:** Alternatives considered include: (1) Divide the scope into individual projects by SAP application. This alternative was not selected because the efforts are interrelated and completing them separately could lead to duplication of work, especially testing efforts, and therefore potentially higher costs. (2) Migrate to SAP S/4HANA. This option was not selected at this time because it is part of the long-term digital plan and requires substantial planning and investment, (3) Balance the project scope through regular support pack upgrades. This alternative was selected because it provides the best balance of minimizing cost and maintaining support by combining multiple application upgrades through a single support pack upgrade effort.

- The **SiteCore Primary Upgrade 2025** project requires $119,148 in capital and $124,709 in O&M in the test year.

  - **Description:** The project will refresh all components of the website hosting, delivery, search, and analytics applications to add new features and improve search capabilities. Sitecore is the content management application for consumersenergy.com website, a channel many customers use for accessing account information and bill payment.

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

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

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

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

Q. Are there any Upgrades and Replacements projects with large variances that need explanation?

A. Yes. The following other Upgrades and Replacements area IT project is addressed below.

- ESB Application 2020-2021 Upgrade

Q. Please explain the difference in the projected total company and gas allocation capital and O&M costs in Gas Rate Case No. U-21148 for the for ESB Application 2020-2021 Upgrade project.

A. My testimony below will explain the difference in the projected total company and gas allocation capital and O&M costs between Gas Rate Case No. U-21148 and the current projected capital costs.

Q. What were the original total company and gas allocation capital and O&M business case projected capital costs in Gas Rate Case No. U-21148?

A. The original total company and gas allocation project capital costs in Gas Rate Case No. U-21148 are in the table provided below.

Enterprise Service Bus Application 2020-2021 Upgrade					
Case No. U-21148					
Cost Category	**Capital**		**O&M**		
	Total Company	**Gas Allocation**	**Total Company**	**Gas Allocation**	**Reference**
2020 Actuals					
Software	$0	$0	$0	$0	A-131 (DDP-7), line 5, columns j and p
Material	$0	$0	$0	$0	A-131 (DDP-7), line 5, columns k and q
Labor	$0	$0	$20,789	$7,068	A-131 (DDP-7), line 5, columns l and r
Contractor	$0	$0	$43,127	$14,663	A-131 (DDP-7), line 5, columns m and s
Overhead & Other Costs	$0	$0	$4,612	$1,568	A-131 (DDP-7), line 5, columns n and t
Total 2023 Actuals	**$0**	**$0**	**$68,527**	**$23,299**	A-131 (DDP-7), line 5, columns i and o
2021 Projected					
Software	$0	$0	$0	$0	A-131 (DDP-7), line 120, columns j and p
Material	$0	$0	$0	$0	A-131 (DDP-7), line 120, columns k and q
Labor	$446,239	$133,916	($276,983)	($94,174)	A-131 (DDP-7), line 120, columns l and r
Contractor	$1,318,130	$395,571	$269,015	$91,465	A-131 (DDP-7), line 120, columns m and s
Overhead & Other Costs	$109,225	$32,778	$27,673	$9,409	A-131 (DDP-7), line 120, columns n and t
Total 2023 Projected	**$1,873,594**	**$562,266**	**$19,705**	**$6,700**	A-131 (DDP-7), line 120, columns i and o
Total Projected					
Software	$0	$0	$0	$0	
Material	$0	$0	$0	$0	
Labor	$446,239	$133,916	($256,195)	($87,106)	
Contractor	$1,318,130	$395,571	$312,142	$106,128	
Overhead & Other Costs	$109,225	$32,778	$32,285	$10,977	
Total Actuals/Projected	**$1,873,594**	**$562,266**	**$88,232**	**$29,999**	

Q. What are the projected total company and gas allocation capital and O&M costs for the ESB Application 2020-2021 Upgrade project in Case No. U-21490?

A. The Case No. U-21490 projected total company and gas allocation capital and O&M costs for the ESB Application 2020-2021 Upgrade project are in the table provided below.

Enterprise Service Bus Application 2020-2021 Upgrade					
Case Nos. U-21148. U-21308, and U-21490					
Cost Category	Capital		O&M		
	Total Company	Gas Allocation	Total Company	Gas Allocation	Reference
2020 Actuals					
Software	$0	$0	$0	$0	A-131 (DDP-7), line 5, columns j and p
Material	$0	$0	$0	$0	A-131 (DDP-7), line 5, columns k and q
Labor	$0	$0	$20,789	$7,068	A-131 (DDP-7), line 5, columns l and r
Contractor	$0	$0	$43,127	$14,663	A-131 (DDP-7), line 5, columns m and s
Overhead & Other Costs	$0	$0	$4,612	$1,568	A-131 (DDP-7), line 5, columns n and t
Total 2023 Actuals	**$0**	**$0**	**$68,527**	**$23,299**	A-131 (DDP-7), line 5, columns i and o
2021 Actuals					
Software	$0	$0	$0	$0	A-21 (SHB-6), line 94, columns l and r
Material	$0	$0	$0	$0	A-21 (SHB-6), line 94, columns m and s
Labor	$232,654	$69,819	$16,363	$5,563	A-21 (SHB-6), line 94, columns n and t
Contractor	$1,280,479	$384,272	$190,569	$64,794	A-21 (SHB-6), line 94, columns o and u
Overhead & Other Costs	$223,344	$67,025	$37,931	$12,897	A-21 (SHB-6), line 94, columns p and r
Total 2023 Projected	**$1,736,476**	**$521,117**	**$244,864**	**$83,254**	A-21 (SHB-6), line 94, columns k and q
2022 Actuals					
Software	$28,738	$8,624	$0	$0	A-20 (SHB-5), line 95, columns l and r
Material	$0	$0	$33,333	$11,667	A-20 (SHB-5), line 95, columns m and s
Labor	$379,487	$113,884	$130,985	$45,845	A-20 (SHB-5), line 95, columns n and t
Contractor	$1,319,592	$396,009	$139,912	$48,969	A-20 (SHB-5), line 95, columns o and u
Overhead & Other Costs	$415,587	$124,718	$17,811	$6,234	A-20 (SHB-5), line 95, columns p and r
Total 2023 Projected	**$2,143,404**	**$643,236**	**$322,041**	**$112,714**	A-20 (SHB-5), line 95, columns k and q
2023 Projected					
Software	$894	$287	$50,001	$17,500	A-20 (SHB-5), line 201, columns l and r
Material	$0	$0	$116,667	$40,833	A-20 (SHB-5), line 201, columns m and s
Labor	$505,365	$162,121	$292,903	$102,516	A-20 (SHB-5), line 201, columns n and t
Contractor	$614,948	$197,275	$499,905	$174,967	A-20 (SHB-5), line 201, columns o and u
Overhead & Other Costs	$465,584	$149,359	$29,852	$10,448	A-20 (SHB-5), line 201, columns p and r
Total 2023 Projected	**$1,586,791**	**$509,043**	**$989,327**	**$346,265**	A-20 (SHB-5), line 201, columns k and q

Total Projected					
Software	$29,632	$8,911	$50,001	$17,500	
Material	$0	$0	$150,000	$52,500	
Labor	$1,117,506	$345,825	$461,040	$160,992	
Contractor	$3,215,019	$977,557	$873,513	$303,393	
Overhead & Other Costs	$1,104,514	$341,102	$90,205	$31,146	
Total Actuals/Projected	**$5,466,671**	**$1,673,395**	**$1,624,759**	**$565,532**	

Q. Why have the total project actuals and projected capital and O&M costs for the ESB Application 2020-2021 Upgrade project changed from projections presented in Case No. U-21148?

A. The total company project actuals and project capital and O&M costs for the ESB Application 2020-2021 Upgrade project increased from the projections presented in Case No. U-21148 due primarily to a delay in the second release. This project had two planned releases in 2021. The first release occurred as planned in June 2021. The second release, originally scheduled for October 2021, was delayed due to technical challenges and resource constraints that occurred during project execution and a timing conflict with the Advanced Distribution Management System ("ADMS") project. The technical challenges included integration issues with a custom module of the ESB used for Common Logging and Exceptions and integration with the Demand Response Management System. There were also ADMS resource constraints needed to support the ESB testing. The timing conflict with the ADMS project resulted in a delay of eight months and an additional cost associated with testing. The existing version of the ESB application was at end of support and given the critical nature of this application for supporting integrations this project was required to ensure there was no impact to critical business processes.

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

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

- Column (a) provides the application name;
- Column (b) provides a disaster recovery Tier, where applicable;
- Column (c) provides total projected 2024 capital expenditures;
- Column (d) provides total projected 2024 O&M expense;
- Column (e) provides total projected 2025 capital expenditures;
- Column (f) provides total projected 2025 O&M expense;
- Column (g) provides total test year capital expenditures;
- Column (h) provides total test year O&M expense;
- Column (i) provides the gas allocation for test year capital expenditures; and
- Column (j) provides the gas allocation for test year O&M expense.

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

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

A. The Application Currency program focuses on upgrades that maintain security and reliability of the application and underlying platforms, as well as maintaining vendor supported software versions. Not every application requires an upgrade each year, so the application data provided in Confidential Exhibit A-23 (SHB-8) is not inclusive of all applications that are in upgrade cycles beyond the test year. The Company considers the following when determining the next upgrade version:

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

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

Q. Please explain the Application Currency projects.

A. The following describes the Application Currency projects:

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

- **Description:** These initiatives will utilize capital and O&M funding to keep applications current for security and reliability. O&M is included with capital projects to complete expense activities associated with capital upgrades.

- **Problem Statement:** The Company manages a large number of applications in the technology landscape that require regular version upgrades to maintain vendor-supported software versions. Without vendor supported versions, the Company loses the ability to receive version updates and upgrades to address defects, patch security vulnerabilities, protect against cyberthreats, protect data, and add new features. Failure to upgrade these applications can have a direct negative impact on key customer and business processes, increase support costs, increase unplanned outages, and increase cyber security vulnerabilities.

- **Objectives:** Maintaining the appropriate versions of applications through application currency upgrades adds value by: (1) enabling the Company to maintain vendor support; (2) remediating vendor security vulnerabilities and enhancing security protections; (3) addressing vendor defects that impair stability and functionality, leading to fewer incidents due to outdated software; and (4) addressing version interdependencies and compatibility between systems. This is essential to delivering safe, reliable, and affordable service to the Company's customers. The application upgrades in scope are regularly prioritized based on considerations that include application criticality; number of versions behind the current available version; security and operational risk; operational impacts of performing the upgrade; ability to defer; and cost.

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

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

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

Project	Projected Test Year Capital	ROM Adjusted Test Year Capital	Projected Test Year O&M
Application Currency-Corporate-Capital	$63,735	$50,988	$17,122
Application Currency-Corporate-O&M	$0	$0	$62,475
Application Currency-Customer-Capital	$94,085	$75,268	$105,968
Application Currency-Customer-O&M	$0	$0	$71,062
Application Currency-Electric & Gas Shared-Capital	$23,521	$18,817	$97,226
Application Currency-Electric & Gas Shared-O&M	$0	$0	$43,563

Application Currency-Gas-Capital	$26,250	$21,000	$120,375
Application Currency-Gas-O&M	$0	$0	$373,068
Application Currency-IT/Digital Foundation-Application Platforms-Capital	$23,370	$18,696	$31,530
Application Currency-IT/Digital Foundation-Application Platforms-O&M	$0	$0	$80,833
Application Currency-IT/Digital Foundation-Infrastructure Platforms-O&M	$0	$0	$59,901
Application Currency-Operational Technology-Capital	$31,570	$25,256	$14,928
Application Currency-Operational Technology-O&M	$0	$0	$44,801

Enhancement Projects

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

A. Exhibit A-24 (SHB-9) is the Projected Versus Actual Enhancement Capital Expenditures and O&M Expense Summary and Analysis. Page 1 provides a summary of enhancement projected and actual spend for the years 2018 through 2025. Specifically:

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

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

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

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

Q. What is the purpose of Enhancements investments?

A. Enhancements are smaller, short-cycle technology efforts to implement new or improved functionality and provide the flexibility needed to respond to rapidly changing business and customer conditions. Enhancement requests typically emerge from new or changing business conditions, compliance requirements, customer feedback, automation efforts, waste elimination efforts, and other improvement ideas. Enhancements benefit customers and the Company through cost savings, cost avoidance, productivity improvements, safety improvements, efficiencies, mandated regulatory changes, and improved customer experience.

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

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

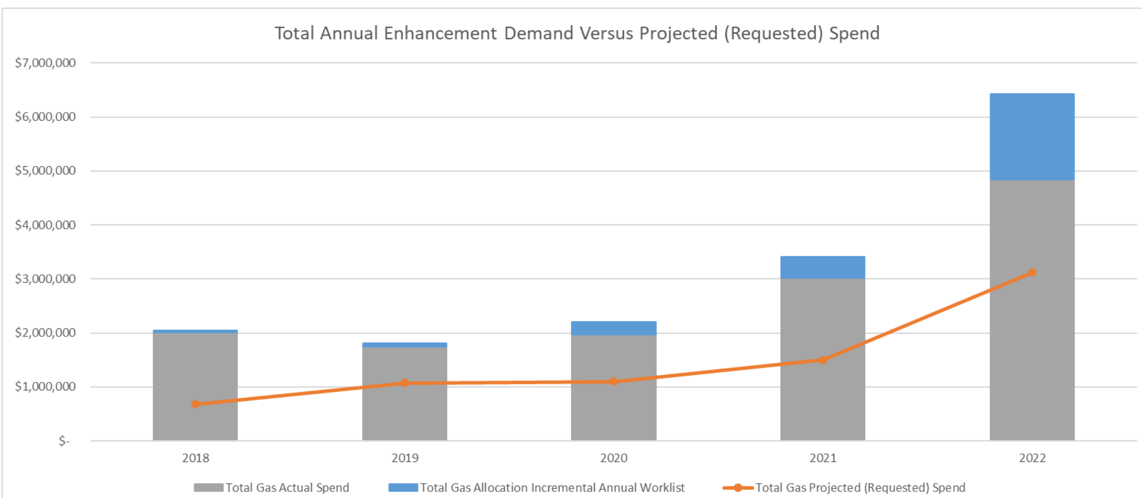
- Column (a) provides the Enhancement open date, internally referred to as the Demand Ticket Open Date;
- Column (b) identifies the Demand Ticket Number, which is used to internally track the lifecycle of the Enhancement request;
- Column (c) identifies the Demand Ticket Type;
- Column (d) provides a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

Q. How does the Company track and manage enhancements?

A. The Company actively maintains a worklist of enhancements, Exhibit A-25 (SHB-10). Each enhancement is tracked in detail from idea to completion including steps for value justification, estimation, prioritization, final funding approval, execution, and closure. For an enhancement to seek funding approval, it must be qualified with a cost estimate and benefits to ensure the enhancement is ready for execution. Once approved for funding in cross-functional business team reviews, the enhancement is scheduled. When the enhancement begins execution, the status for enhancement records is updated by enhancement request coordinators through closure. This provides the Company with an auditable tracking method for every enhancement request.

Q. Please explain the historical demand for enhancements and the Company's projection for future enhancement demand.

A. The demand for enhancement efforts has grown an average of 46.7% over the past three years because of the increased need for automation efforts, focus on waste elimination and cost optimization, additional functionality requests to optimize aging applications, and enhanced functionality requests for newly implemented technology. In 2022, the Company spent 55% above the projected capital and O&M, as reflected in the summary for Exhibit A-25 (SHB-10), page 2 and the graph below.



As of October 2023, the Company has a worklist (Exhibit A-25 (SHB-10)) of 627 requests Company-wide to improve multiple applications and systems. This well-known worklist demonstrates the high volume of demand for smaller technology efforts. Despite exceeding the projected spend in previous years, the Company is unable to keep up with the growing demand for enhancements, as shown on Exhibit A-24 (SHB-9), page 2. The projected Total Gas Allocation Cumulative Worklist (Demand) for the test year is $4,904,732 (Exhibit A-24 (SHB-9), page 2, line 7, column j), while the Company is projecting only $3,800,692 of Total Gas Projected Spend (Exhibit A-24 (SHB-9), page 2, line 2, column j). To recognize this increasing demand and better project Enhancement costs, the Company is projecting these costs by determining incremental enhancement demand for 2024 and 2025 based on a known worklist, plus applying a combination of historical demand and historical spend. The projected level of demand still outpaces projected spend, as indicated above.

Q. What methods is the Company using to ensure projected enhancement expenditures and expenses in the test year are reasonable and prudent?

A. The Company is using two methods to validate enhancement demand expenditures and expenses in the test year: (1) Three-year historical average, and (2) Total cumulative demand. For the three-year historical average method, the Company calculated the actual three-year historical average for 2021-2023 of $4,065,719 and compared it to the projected Test Year enhancement expenditures and expenses of $3,800,692. This validates Test Year projections are in line with historical spending. Then for the total cumulative demand method, the Company compared the Total Gas Allocation Cumulative Worklist amount of $4,904,732, in Exhibit A-24 (SHB-9), page 2, line 7, column j, to the projected Test Year enhancement expenditures and expenses of $3,800,692. This comparison validates these projections are lower than the projected demand.

Q. Please further explain the Company's calculation for the cumulative worklist amount.

A. Projections for the total cumulative worklist in 2024 and 2025 are based on the three-year average annual increase to enhancement demand. As indicated, cumulative enhancement requests grew at an average annual rate of 46.7% over the past three years. As a result, the cumulative worklist for enhancements (Exhibit A-25 (SHB-10)) continues to grow year-over-year, as depicted on Exhibit A-24 (SHB-9), page 2, row 7. By validating the projected Enhancement spending based on a known worklist and a three-year historical average of actual spend the Company's test year projected spend of $3,800.692 is reasonable and prudent.

Q. Please explain the Product Family Enhancements projects.

A. The following are the Product Family Enhancements projects, formerly referred to as Enhancements:

- The **Product Family Enhancements - Capital** and **Product Family Enhancements - O&M** requires the capital and O&M in the test year as described in the table below.
    - **Description:** These projects will utilize capital and O&M funding to make enhancements to existing software and to address requests generated by changing business requirements. O&M is included with capital projects to complete expense activities associated with capital enhancements.
    - **Problem Statement:** As business processes improve and change, new requirements surface that call for smaller-effort software application changes that typically emerge from new or changing business conditions, compliance requirements, needs for new capabilities, customer feedback, and other improvement ideas. Enhancing applications requires a short timeframe between inception and implementation and cannot and should not wait for rate case approval at an individual line-item level. Failure to make these changes to applications can have a direct negative impact on key customer and business processes, increase support costs, and limit the Company's ability to consistently meet objectives.

- **Objectives:** The value of software enhancements lies in: (1) cost savings and cost avoidance; (2) technology and business process efficiencies; (3) improved customer experience; (4) risk mitigation; (5) safety improvements; and (6) achieving corporate goals, among others. While these small-work software efforts are neither projects nor operational work, funding for resources is still required to maintain business agility in the digital environment. Included in the implementation are small changes and functionality improvements to existing IT software application investments for the respective business areas.

- **Scope:** The scope of application enhancements encompasses: (1) making necessary system changes; and (2) updating documentation related to the changes. Additionally, enhancement requests are fulfilled to provide new functionality for business areas represented by each program.

- **Alternatives:** Prior to implementing an enhancement, a review is completed to identify the best solution. During that review, requests for this funding are governed by a cross-functional board comprised of representatives from each area that routinely evaluates and prioritizes the work and to assess requests for value using categorized benefits. In addition, the overall enhancements budget is reviewed annually, and the alternative of a zero-budget allocation for enhancements is considered. This project fortifies the Company’s ability to make software changes as part of process improvements and regulatory changes, and to meet legally required system changes. Without funding for enhancements, the Company will be limited in its ability to quickly provide needed capabilities and improvements.

Specific spend requirements for each product family Enhancement project are indicated in the table below.

Project	Projected Test Year Capital	ROM Adjusted Test Year Capital	Test Year O&M
Product Family Enhancements-Corporate-Capital	$415,780	$415,780	$75,758
Product Family Enhancements-Corporate-O&M	$0	$0	$99,871
Product Family Enhancements-Customer-Capital	$716,794	$716,794	$47,904
Product Family Enhancements-Customer-O&M	$0	$0	$258,582
Product Family Enhancements-Electric & Gas Shared-Capital	$219,719	$219,719	$16,298
Product Family Enhancements-Electric & Gas Shared-O&M	$0	$0	$59,379
Product Family Enhancements-Gas-Capital	$531,250	$531,250	$26,750
Product Family Enhancements-Gas-O&M	$0	$0	$100,303
Product Family Enhancements-IT/Digital Foundation-Capital	$687,433	$687,433	$325,051
Product Family Enhancements-IT/Digital Foundation-O&M	$0	$0	$219,818

Digital Foundations and Capabilities Projects

Q. Please explain the Digital Foundations and Capabilities projects.

A. Below are the Digital Foundations and Capabilities projects:

- The **Digital-Cloud Data and Analytics Platform** project requires $501,849 in capital and $141,125 in O&M in the test year.
  - **Description:** This project will provide Artificial Intelligence and analytics in the cloud across the business to uncover new paths to value, faster, allowing the organization to make better decisions and enable delivery outcomes for the NGDP, Electric Grid Integration, customer programs, and other business needs. The project will additionally establish data governance roles and responsibilities, processes, and implement tools to support best practices across the enterprise.
  - **Problem Statement:** Consumers Energy faces several challenges in the ongoing data modernization journey, which include: (1) legacy data platform operations; (2) long lead times for data exploration and identification of data assets; (3) lack of data ownership and quality; (4) limited data governance best practices across data

ownership, access control & security; and (5) heavy dependence on IT for Business Intelligence reporting and analytics.

- **Objectives:** The project will add value by providing data to support business needs by: (1) optimizing data platform operations costs with workflow-based platform infrastructure deployment using pre-built modules and templates; (2) reducing data operations build complexity and data engineering costs through automation; (3) improving data quality and governance that leads to reduced costs of data provisioning, data duplication, and improved data accuracy; (4) streamlining data access requests, management, and governance to reduce risks and support efficiency; and (5) increasing the speed to deliver new data and data capabilities, improving productivity, and improving access to data. This project is an enabler for business areas to use these capabilities to build analytic models for asset and labor optimization that is anticipated to more than offset the project costs.

- **Scope:** The project scope includes: (1) developing and modernizing the analytics platform in the cloud to allow Consumers Energy to implement new use cases leveraging simplified infrastructure configurations and automated deployment processes; (2) build and deploy data management capabilities, controls, catalog, assets, and data flow; (3) developing data ordering workflows and data access management controls; (4) prioritization and new datasets; (5) simplifying infrastructure configuration; (6) automating deployment processes; and (7) enabling data governance tools and processes.

- **Alternatives:** Alternatives considered include: (1) Address current pain points in existing on-premise and cloud analytics platforms. This alternative was not selected because the existing platforms requires new investment in licensing and infrastructure, delivery for new capabilities cannot keep pace with demand, still requires investment to address legacy system technical obsolescence, and business areas would not realize asset and labor optimizations. (2) Continue to utilize existing on-premise and cloud analytics platforms. This alternative was not selected because it would not address the current pain points in the existing on-premise and cloud analytics platforms, limiting the Company's ability to have required data and analytics capabilities to improve processes and realize asset and labor optimizations. (3) Implement a new data and analytics platform in the cloud. This alternative was selected because it provides improved analytics capabilities, faster access to data that is critical to improve business process, and reduces technical obsolescence.

- The **Digital-Hybrid Cloud and Data Center Migration** project requires $616,557 in capital and $195,437 in O&M in the test year.

  - **Description:** This project will optimize data center assets and asset replacement project purchases by migrating or retiring applications out of existing Company and co-location data centers into cloud services, reducing operational costs for running IT services and leveraging increased cloud capabilities to improve the efficiency, quality, and speed-to-market of customer-facing and internal IT services.

- **Problem Statement:** The technology currently deployed in the Company's data centers meets many customers' needs today. However, the pace of digital transformation is increasing rapidly, and requirements for applications are evolving faster than the technology in the Company's data centers can respond in a cost-effective manner. These data center constraints lead to longer implementation times, missing capabilities, or reduced functionality in the applications that the Company can deploy.

- **Objectives:** This project will create value by ensuring the Company's technology requirements are met through a comprehensive and cost-effective combination of data centers and public cloud services. Specifically, by migrating applications to cloud services, the project will: (1) reduce capacity, hardware maintenance, and security device costs at the co-location data center; (2) reduce hardware maintenance and security device costs at the production data center; (3) enable the ability to scale infrastructure quickly up or down without costly up-front hardware purchases; (4) reduce application risk through cost-effective, scalable infrastructure redundancy and availability; (5) reduce ongoing server and storage asset replacement costs; (6) reduce ongoing networking equipment replacement costs; (7) reduce operational support costs; and (8) enable the use of a vast array of cloud services to support Company applications.

- **Scope:** The project scope includes: (1) promoting the robust main co-location data center to become the primary data center for on-premise IT services; (2) demoting the Company's production data center to the disaster recovery data center for on-premise IT services; (3) analyzing applications for migration to cloud or retirement; (4) migrating applications from on-premise to cloud; (5) transforming applications to use cost-effective cloud services; (6) altering network architecture and deploying base infrastructure to allow each location (on-premise or in cloud) to function independently; (7) deploying cloud and on-premise cost management tooling and processes; (8) simplifying and optimizing backup and disaster recovery resources and processes using cloud services; (9) implementing additional automation for application deployment and management; (10) changing the operations model for support of cloud-based applications; (11) educating and increasing the skills of IT and other employees in leveraging public cloud services; and (12) transforming IT to become the broker of cloud services for the Company.

- **Alternatives:** Alternatives considered included: (1) migrating to public cloud services faster. This alternative was not chosen because the Company's ability to absorb new technologies coupled with the investments the Company has already made in data center equipment would prevent a faster move from being efficient and effective, introducing additional financial risk; (2) migrating to public cloud services slower or not at all. This alternative was not selected because delaying public cloud services and capabilities coupled with requiring an extension of the life of existing data center equipment creates increased financial and operational risk; and (3) contracting with an outside vendor to provide cloud services to run applications for the Company. This alternative was not selected because industry information shows the option as not yet cost effective or not providing a maturity level that the Company would be able to easily consume with limited in-house experience and expertise in public cloud. The alternative to migrate to a hybrid cloud and data center model was selected because of the expected cost benefits and technology capabilities it provides to the Company over a timeline that allows the Company to realize the value of existing investments.

- The **Enterprise Print - Scan Suite** project requires $51,292 in capital and $18,964 in O&M in the test year.
  - **Description:** The projects intent is to upgrade the current Enterprise Print and Capture suite for improved data security and integration for the work from home business partner.
  - **Problem Statement:** The company currently maintains a print and capture suite that will have support ending in 2025. Only high-level security patches will be available after this date. The company maintains a fleet of servers that are scheduled to be upgraded. The current print and capture suite is not compatible with the targeted server operating systems. The lack of internal resources requires the company to continue to absorb increased costs to contract administrative personal.
  - **Objectives:** This project maintains cost savings achieved by eliminating wasteful print jobs and further enables a productive, and flexible workforce for business partners working remotely. This project also ensures that the latest data transmission security requirements are met by the solution.
  - **Scope:** The project scope includes: (1) upgrading the current suite to the latest version; (2) consolidating the amount of print servers in the environment; (3) training for company personal to administer the suite; (4) converting all workflows from the current system; (5) implementing remediation for security vulnerability risk;. (6) integrating device management with Enterprise Configuration Management Database (CMDB) for asset tracking and monitoring.
  - **Alternatives:** Alternatives considered: (1) migrating to cloud services. This alternative was not chosen at this time due to maturity levels found with subscription services. (2) other print-scan products. This alternative was not selected as it would required new print and scanning specific to another print-scan product. (3) Print-scan products that were less costs. This alternative was not selected, due to fewer capabilities offered than the current product, which would introduce inefficiencies in the current processes. (4) upgrade current product. This alternative was chosen due to lower overall cost of not requiring new hardware, maturity of current product, and providing same level of capabilities required to support current processes.

- The **SAP HANA Database Migration** project requires $159,186 in capital and $7,423 in O&M in the test year.
  - **Description:** In preparation for SAP's planned end of support for its Business Suite product in 2027, the Company will migrate its existing SAP databases from Oracle to SAP HANA in advance of the required move to S/4HANA.
  - **Problem Statement:** The Company's SAP applications currently utilize Oracle's relational database management system as their underlying database storage technology. SAP has informed its customers that standard support for its legacy Business Suite (aka ECC) product will end in 2027, along with support for all non-SAP database platforms. SAP has also informed customers that the future direction for their enterprise solution is S/4HANA, a solution built explicitly for their HANA database platform. To prepare for these upcoming events, the company will migrate all of its SAP databases off of Oracle and onto SAP HANA.
  - **Objectives:** This project lays the groundwork for the company's eventual shift to SAP's HANA-based solutions by: (1) proactively migrating SAP databases to a database technology that is fully supported by SAP beyond 2027; and (2) mitigating the risk of a complete loss of support for the current Oracle database technology in 2027.
  - **Scope:** Project scope includes: (1) procurement of HANA software licensing to cover all migrated SAP applications; (2) data migration for all SAP applications from the Oracle database to SAP HANA; and (3) implementation of new application support policies, procedures and tools required to manage the newly migrated SAP HANA applications.
  - **Alternatives:** Given SAP's announcement regarding the end of support for its ECC product in 2027, all customers running SAP on database software other than HANA will also lose support for their associated database software in 2027. SAP is offering no other options for databases other than HANA beyond 2027. While there is no alternative to the HANA database for SAP going forward, the Company has considered multiple options: (1) Perform a direct migration from SAP Business Suite on Oracle to S/4HANA. A direct migration to S/4HANA brings greater operational risk to the Company as both the underlying database technology and the SAP application's functionality would change simultaneously, so this alternative was not selected. (2) Remain on the current SAP Business Suite product but competitively bid support services to a third-party provider instead of SAP. This alternative was not selected because moving to a third-party support model forces the Company to remain on outdated SAP software and eliminates any possibility of benefitting from new business functionality provided by S/4HANA. It will also require the Company to accept significant risk due to the fact that SAP security patches, application patches and upgrades will not be available upon termination of the SAP maintenance agreement. (3) Migrate to SAP's Software as a Service (SaaS) implementation of S/4HANA. This alternative was not selected because an S/4HANA SaaS migration is a much more disruptive option as the

Company's business processes must be adjusted to accommodate functionality differences between ECC and S/4HANA. The risk of negative business impact is significantly greater than simply changing the underlying database technology. The selected alternative to migrate the SAP databases to HANA prior to implementing S/4HANA gives the Company several years to solidify its HANA database infrastructure before introducing the substantial business process changes required with S/4HANA.

- The **Enterprise Portal Improvement** project requires $16,640 in O&M in the test year.
  - **Description:** The Enterprise Portal Improvement project will increase productivity by improving access to the portal.
  - **Problem Statement:** Today users receive multiple error messages when accessing the Enterprise Portal impacting usability and creating process inefficiencies.
  - **Objectives:** The project provides value for the Company by: (1) improving access to the portal eliminating errors that create inefficiencies; and (2) offering a more user-friendly experience increasing productivity.
  - **Scope:** The project scope includes improving portal access and usability.
  - **Alternatives**: Three alternatives were considered for this project: (1) continue using the portal as-is. This alternative was not selected as it does not reduce inefficiencies and improve usability; (2) replace the current portal with a new solution. This alternative was not selected as it is not cost-effective; (3) improve the current portal to eliminate access errors and improve usability. This alternative was selected, as it reduces inefficiencies, improves usability, and is the most cost-effective.
- The **Tibco API Exchange Gateway Replacement** project requires $62,176 in capital and $7,423 in O&M in the test year.
  - **Description:** This project is looking to retire the API Exchange Gateway within the Tibco ESB and replace it with a new solution called Microsoft Self-Hosted Gateway. The API Exchange Gateway is used by the Tibco ESB to integrate to external vendors, all new development will need to be done to integrate this solution.
  - **Problem Statement:** The Tibco API Exchange Gateway is anticipated to be sunset by the vendor, as they have already dropped all development of enhancements for the platform.
  - **Objectives:** This project creates value for the Company by: (1) Avoiding the risk of running a project no longer supported by the vendor (i.e. the Tibco Enterprise Service Bus API Exchange module), and (2) Enabling the Company the opportunity to move to a product that is more stable, secure, and usable.

- **Scope:** The project scope includes: (1) Conducting a Request for Proposal to procure a replacement product and work with architecture team to migrate the product. (2) Migrate all current work items to the new platform. (3) Conduct appropriate testing to ensure all Service Level Agreements are met.

- **Alternatives:** Alternatives considered include: (1) Evaluating the replacement of the current product with a new product that is not already in the Company environment. This alternative was not selected because it would not be cost effective. (2) Keeping the current application as-is. This alternative was not selected as the vendor for the current platform has stopped all development for this product. (3) Leveraging an existing solution already in the Company environment. This alternative was selected as it avoids multiple solutions with redundant capabilities and avoids costs for supporting and maintaining a second solution.

Q. Please provide the detailed cost savings the Company expects as a result of the implementation of the Digital–Hybrid Cloud and Data Center Migration project.

A. In addition to the non-financial benefits described above, the Company expects the annual total Company savings and gas allocation Capital and O&M cost savings, as shown in the following chart, once the project is complete. The O&M and Capital reductions are shown in Exhibit A-21 (SHB-6) in the Value & Impacts Summary section under each of the Reduction rows. These annual savings are comprised of Company capital hardware purchases saved, resulting in reduction to colocation data center lease costs housing the hardware, hardware and software maintenance reduction by having less hardware to maintain, managed service provider, and ARP – Server and Storage labor O&M costs reduction by maintaining and upgrading less physical hardware once the project is complete in 2025.

Projected Total Company Savings – Annual					
Capital	**Investments O&M**	**Operations O&M**			
Hardware	ARP -Server and Storage	Colocation Lease	Hardware/Software Maintenance	Managed Service Provider Support	**Total Operations O&M**
$5,060,984	$520,685	$819,001	$1,763,140	$855,930	**$3,438,071**

Projected Gas Allocation Savings – Annual					
Capital	**Investments O&M**	**Operations O&M**			
Hardware	ARP -Server and Storage	Colocation Lease	Hardware/Software Maintenance	Managed Service Provider Support	**Total Operations O&M**
$1,623,564	$182,240	$305,996	$ 671,852	$319,792	**$1,297,640**

Q. Do the Digital–Hybrid Cloud and Data Center Migration savings exceed the Total Cost of Ownership of the project?

A. Yes. Using the Company's internal BPS calculation, the B/C Ratio Overall of 0.153 in Exhibit A-21 (SHB-6) is greater than the breakeven point of 0. This indicates that the projected hard cost savings achieved by the project exceed the total cost of investment including ongoing support costs. The investment savings will exceed the cost of the project including projected ongoing support costs in 2027.

Q. Are the expenses and expenditures identified in this testimony reasonable and prudent?

A. Yes. The O&M expenses and capital expenditures requested in this case will help the Company achieve the outcomes of the NGDP, continually improve the experience of customers' interactions with the Company and maintain a reliable and secure technology base that is exposed to ever-increasing and serious cyber security threats over time. Technology is the backbone of Company operations and two-way customer communications. The Company has demonstrated the prudency of project expenditures and operational O&M requirements.

This testimony has provided detailed synopses of each project, a supplementary exhibit of the total project cost, hard savings, and cost/benefit analysis for each project in the test year, and a deep dive into benefits for several high priority projects. These are responses to concerns from previous rate cases and to provide additional insight to support recovery prior to the short analysis period in audit and discovery. The Company is seeking full recovery for these investments and operational expenses for technology solutions that keep its systems available, customers safe from growing cyber security threats, and that deliver on an improved gas future in the NGDP plan.

Q. Does this conclude your direct testimony?

A. Yes.

S T A T E O F M I C H I G A N

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the application of **CONSUMERS ENERGY COMPANY** for authority to increase its rates for the generation and distribution of electricity and for other relief.	))))))	Case No. U-21490

DIRECT TESTIMONY

OF

BRADLEY S. BAMMERT

ON BEHALF OF

CONSUMERS ENERGY COMPANY

December 2023

Q. Please state your name and business address.

A. My name is Bradley S. Bammert, and my business address is One Energy Plaza, Jackson, MI 49201.

Q. By whom are you employed?

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

Q. What is your position with Consumers Energy?

A. My current position title is Manager Privacy and Risk with responsibility for leading the Privacy and Risk Management Team as part of the Governance, Risk, and Compliance department within the Company's Security organization.

Q. Please state your educational background.

A. I hold a Bachelor of Science Degree from Ferris State University in Computer, Networks and Systems with a minor in digital forensics. Additionally, I am currently certified as an information systems auditor with the Information Systems Audit and Control Association, Cyber Security & Infrastructure Security Agency ("CISA"), in good standing since 2013.

Q. Please state your work experience and current responsibilities.

A. I have 12 years of experience at Consumers Energy with expertise in information security assurance, risk management, project management, and leadership. I spent the first five years of my career auditing internal controls over financial reporting as part of the Company's integrated internal audit, as well as providing support to our external auditor. From there, I moved into the Security organization as a project manager where I managed scope, risk, issue, change management, schedules, resources, and budgets. Most recently, I was hired to manage our Privacy and Risk Management team which develops and operates processes to assess and manage the financial, reputational, and regulatory risks facing the Company regarding confidentiality, integrity, and availability of its digital assets.

Q. What is your regulatory experience?

A. Throughout my career, I have had responsibility for implementing regulatory mandates and providing governance and oversight of the ongoing adherence to regulatory mandates. In my current role, I have participated in gathering data and developing documentation to support rate case testimony, and I have also participated in the Customer Education and Participation workgroup meetings with the Michigan Public Service Commission ("MPSC" or the "Commission") Staff ("Staff") and stakeholders.

Q. Please explain the purpose of your direct testimony in this proceeding.

A. The purpose of my direct testimony is to describe the Security Department's Operating and Maintenance ("O&M") expenses and capital expenditures needed to maintain existing security systems and enable future capabilities. In addition, this direct testimony provides an overview of threats that are increasing in both Cyber Security and Physical Security spaces and how they have evolved over time. This evolution, coupled with a changing regulatory landscape, leads to a need for increased staffing and O&M funding. These increases are needed to support 24-hour-a-day and seven-days-a-week ("24/7") security monitoring through the Fusion Center, support a move to increased cloud computing solutions, address a pressing need to continue to mature security capabilities, and protect the Company's technology and physical infrastructure.

Furthermore, my direct testimony provides an explanation of the Security Department's plans for deterring threats prior to their impacting the Company and the customers the Company serves, detecting when malicious activity does occur, and recovering quickly with minimal impact while complying with all regulations.

Q. Have you ever testified before the Commission?

A. No; however, I have supported development of testimony and exhibits for Case No. U-21224.

Q. What exhibits are you sponsoring in this proceeding?

A. I am sponsoring the following exhibits:

Exhibit A-12 (BSB-1)	Schedule B-5.2	Summary of Actual and Projected Gas Capital Expenditures;
Exhibit A-27 (BSB-2)		Synopses Containing Descriptions, Scope, Benefits, Implementation Dates and Detailed Costs of Actual and Projected Gas & Common Capital Expenditures and O&M Expenses for the years 2022, 2023, 2024, and 2025;
Exhibit A-28 (BSB-3)		Summary of Actual and Projected Security Operations O&M Expense for the Years 2022, 2023, 2024, and Test Year 12 Months Ending September 30, 2025; and
Exhibit A-29 (BSB-4)		Summary of Actual and Projected Security Investments O&M Expenses for the Years 2022, 2023, 2024, and Test Year 12 Months Ending September 30, 2025.

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

A. Yes.

DESCRIPTION OF THE SECURITY DEPARTMENT

Q. Please provide an overview of the Company's Security Department.

A. The Company's Security Department's purpose is defined in five simple words: Deter, Detect, Recover, Comply, and Enable. Fundamentally, the organization exists to: deter threats prior to impacting the Company, detect when malicious activity does occur, recover quickly with minimal effect if/when a threat is successful in causing impact, comply with all governmental and industry regulations, and enable our business partners and Company to deliver on their goals. The Security Department fulfills its purpose by focusing on specific areas that can be thought of as the midpoint between strategic and tactical items. Security sets standards based on external threats and guides security work required by the Information and Operational Technology ("OT") teams.

To achieve its purpose, the Security Department is made up of five key teams: Compliance, Physical Security, Engineering, GRC (Governance, Risk, Compliance), and Fusion Center. The Compliance team ensures all security related rules and regulations from the industry and government bodies are followed. This includes Commission rules, industry regulations, executive orders, and state and federal laws. The Physical Security team provides physical security services to the enterprise including perimeter protection, security guards, card access, cameras, executive protection, and investigative services as well as the recent addition of the Emergency Management function. The Engineering team designs and deploys new security technology for both physical security and cyber security capabilities, ensures Company projects meet enterprise security standards and conducts vulnerability assessments and penetration tests to find relevant system vulnerabilities. The GRC team provides enterprise security awareness on both physical and cyber security topics, quality assurance, project, program, and financial management, as well as risk management and privacy program services. The Fusion Center team provides a 24/7 combined cyber and physical operations center responsible for all security monitoring, operational support, identity and access management, event detection, and incident response.

Investing in the maturation of the Security Department's capabilities, providing 24/7 security monitoring, and improving on the ability to secure the Company's critical assets benefits not only the Company, but also the Company's customers. Customers benefit from the knowledge that the Company has invested to ensure their data is safe and secure, their privacy is protected, and they can count on the Company to secure both critical technology assets as well as critical infrastructure assets to serve them.

Managing security risks and mitigating associated threats requires a robust, dedicated security program focusing on people, process, and technology. Security can no longer be thought of as simply an operational (physical) or technology (cyber) issue, but an enterprise risk worthy of specialization and focus.

Previous approved rate case funding requests enabled building the Fusion Center for 24/7 cyber security monitoring which included facilities, technology, and staffing. This case demonstrates the sustainment of the staffing levels to support this new team. The core functions of this new team are to prevent negative impacts to the Company's business and customers by delivering actionable intelligence and responding to the right events in the right way through a dedicated 24/7 team. This team combines the domains of physical and cyber security monitoring, security/identity operations, and cyber security incident response into one organization to streamline the detection, response, and resolution processes so that the Security Department can better meet the Company's operational and security needs.

From a compliance standpoint, the Company sees significant increases in federal government scrutiny. Recent Transportation Security Administration ("TSA") directives, while focused on the gas business and critical infrastructure, have many overlaps with the corporate IT environment that required work re-prioritization. Additionally, the gas business will be impacted by President Biden's call for critical infrastructure performance metrics, new North American Electric Reliability Corporation ("NERC")/Critical Infrastructure Protection ("CIP") proposals and numerous bills being proposed in Congress.

Remaining funding requests include investments in technology implementations or enhancements. Security technology implementation projects or enhancements deploy new security capabilities that address specific threats by implementing ways of deterring or detecting attacks. They also ensure that past investments or enhancements approved by the Commission do not become unusable or ineffective.

The security risks facing utilities have never been higher, and the risks require a world-class security program for the benefit of utility customers and the Company. Over the last couple of years, the industry has seen: successful critical infrastructure attacks in the gas (Colonial Pipeline) and water (Oldsmar, FL) sectors in the United States; ransomware payments hitting record highs of $70 million; data breaches costing tens of millions; NERC/CIP compliance fine maximums at $1.3 million per incident per day with companies receiving multi-million-dollar fines in recent years; and the federal government warning that critical infrastructure may be attacked by Russia or China as part of global geo-political tensions.

Q. Please provide an overview of the security challenges utilities face.

A. Security continues to be a significant risk area and challenge for utilities. Traditional physical security issues of protecting publicly accessible, geographically dispersed critical infrastructure are and will continue to be exacerbated as grid resources become more distributed. Cyber security concerns include privacy, data breaches, ransomware, ransom extortion, denial of service (an attack meant to shut down a machine or network, making it inaccessible to its intended users), and critical infrastructure attacks. Recent studies including PwC's 2022 Global Risk Survey and Protiviti's Executive Perspectives for 2022 on Top Risks note cyber security and privacy as some of the top risks to utilities. While cyber security is no longer a new area, each year impacts from cyber security incidents increase. There is no better example than that of the ransomware attacks which occurred in 2020. Ransomware is not a new issue, but since 2020 there has been a significant escalation in ransom payments as attackers became more sophisticated and targeted larger organizations, including Fortune 500 companies. According to a 2023 Sophos report on the state of ransomware, while the rate of ransomware attacks remained flat since 2022, the average payout approximately doubled from $800,000 in 2022 to $1,500,000 in 2023. In addition to ransomware, previously mentioned data breaches, ballooning NERC/CIP compliance fine maximums, and the federal government warning regarding potential critical infrastructure attacks from Russia or China as part of global geo-political tensions, utility security teams must be prepared with plans that balance the need for securing customer data, maintaining compliance, protecting customer privacy, and protecting the critical infrastructure that serves the Company's customers.

The gas security regulatory environment continues to evolve. The TSA regulates gas pipelines federally and their scrutiny has increased on both cyber and physical security. Physical security has seen new requirements for site criticality. Sites that are deemed critical must have specific physical security measures implemented. While the count of critical gas sites has varied over recent years due to changes in the criteria for sites considered critical, the current count is 17 and will likely continue to evolve for the foreseeable future. Although the current count is down from 2022, these changes continue to pose a significant financial impact on the project, reflected in the investment project request "TSA Critical Facilities", as well as additional compliance oversight costs.

Cyber security continues to evolve as well. The TSA issued a security directive in 2021 which required companies to implement an extensive list of highly prescriptive and robust security measures. The TSA has changed approaches over the year after pushback and coaching from the industry. Recently, Security Directive 2 version C was released which replaces the original security directive. Version C was much more outcome focused and required operators to submit cyber security implementation plans to demonstrate required outcomes that will be achieved rather than specifically prescribing what must be done. These plans were submitted in late October 2022. Any costs incurred for the various security directives have been included in the investment project "Pipeline SCADA." This project is also funding the implementation of American Petroleum Institute ("API") 1164 version 2 as required by the MPSC Gas Technical Standard.

TSA Security Directives are only valid for one year. The TSA has stated they plan to begin the formal rulemaking process for mandatory cyber security requirements for gas in the Fall of 2022, and it is expected that the process could take two years. This process will create permanent, mandatory standards like what has been issued on the electric side for NERC/CIP. The TSA has already issued Security Directive 2D ("SD2D") in July of 2023 as the replacement of SD2C. This version has added requirements related to annual submissions to the TSA. The frequent changes to the requirements represent the evolving nature of the regulatory environment related to gas assets and the continued need for agility of our Security program as priorities change.

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

A. Cyber threats are increasing. The most glaring example is ransomware as addressed above. These threats have increased, not only in their impact but also their level of sophistication. Criminal groups are profiting on ransomware, and it has become such a lucrative business that they now conduct cyberattacks in a more sophisticated manner with teams of people who focus on an individual target. Such groups are more focused on Fortune 500 companies because of the potential for large ransom payments.

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

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

First, the threat to critical infrastructure is real and no longer theoretical, as seen with the Colonial Pipeline incident. Even Consumers Energy has seen intrusion attempts from nation-state level actors. The National Security Memo further provided that "[t]he cybersecurity threats posed to the systems that control and operate the critical infrastructure on which we all depend are among the most significant and growing issues confronting our nation."

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

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

In terms of public awareness, the issues of ransomware and attacks against United States critical infrastructure converged in June 2021 when the Colonial Pipeline was shut down for five days after a ransomware attack. This was the first publicly disclosed, successful cyberattack impacting critical infrastructure in the United States. This event has changed the security environment forever and expectations have adjusted accordingly. For instance, the TSA has released two security directives requiring immediate actions from gas owners and operators. The latter requires numerous security controls be implemented in very aggressive timeframes. While the TSA security directive applies to gas, it also applies to shared infrastructure in the Company's corporate and OT environments. Beyond the TSA, the intent is to fund requirements from President Biden's memo out of the Security Enhancement investment project. Some examples of the work include password resets on devices that have restricted access, multi-factor authentication (a process that requires a user to authenticate using more than just a password), allow listing capabilities (a policy that blocks anything that isn't explicitly defined), attestation process development (attestation is a declaration of compliance with standards), and macro disablement (macros are automated ways to perform repeat work in Microsoft Excel).

More recent attacks, such as the Vestas attack, are more specific to the electric business within the utility industry. While this attack was executed outside of the Company's systems, the potential impacts remained as Vestas operated wind generation facilities for Consumers Energy and numerous other utilities. Attacks against third-party suppliers and service providers can significantly impact company operations. In the case of the Vestas attack, Consumers Energy disconnected them from systems and conducted a full investigation to ensure that attackers had not used access into Vestas' systems to compromise any assets at Consumers Energy. Vestas remained disconnected until they were able to conduct a full investigation and provide certainty the attackers were no longer in the environment. As utilities like Consumers Energy continue to diversify and distribute systems and supply chain resources, and more third-party suppliers are injected into the operations, cybersecurity threats will continue to grow. While much of the work associated with investigating and researching this incident involved labor from various security and IT team members, as security requirements continue to increase so will costs. Both external scrutiny and regulatory entities, as well as internal requirements implemented to safeguard systems, also cause IT costs to increase (patching, upgrades, etc.). The Company did not incur any additional costs as a result, and customers were not impacted.

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

A. Cyber security receives much of the national headlines because it is a relatively new risk and does not require physical proximity to execute an attack. However, physical security risks are still extremely relevant in the critical infrastructure space, and they continue to evolve. In the past year, multiple incidents have occurred at other gas utilities where equipment was broken into and tampered with to the point of impacting gas delivery to customers. One utility reported that in December 2020, three separate gas sites were criminally vandalized, all at the same time, causing service disruption of over 3,500 customers for over three days with no gas during extremely cold temperatures. Furthermore, as gas becomes more of a target for environmental scrutiny, the Company may see more attempts to tamper with gas assets. One such example is an incident at a gas city gate where an individual used a stolen excavator to dig at night and nearly hit a gas line. Potential damage could have included thousands of customers without gas and over $10 million in repair costs.

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

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

For remote assets such as city gates the Company needs proactive solutions that can detect, in real time, when someone is inside an asset who should not be there, watch them, and verbally communicate with them. Consider the previously described incident at a city gate where a Company-owned excavator was stolen. The individual then used it to dig dangerously close to gas lines. Both the individual and the Company were very fortunate that nothing happened as a result, but if the Company had the ability to immediately communicate directly to the individual the Company could have warned them of the dangers and possibly could have prevented the excavator from digging near the gas lines. Based upon recent pilot testing of solutions, there are now technology options capable of meeting these objectives. Where more traditional locks are the only practical option for items such as a critical valve, the Company needs appropriate key management and locks made of materials that cannot readily be cut. Proactive approaches such as these will allow the Company to better protect its assets, increase safety, and reduce costs to customers.

Q. What is changing in the regulatory landscape requiring more funding?

A. Specific to gas, the regulatory landscape is changing significantly. Gas pipelines are regulated by the Department of Transportation through the TSA. The TSA has a set of physical security guidelines with which operators are expected to comply. These guidelines must be applied to gas facilities based upon their defined criticality. After the TSA's guidelines update to the gas utility industry and additional analysis on the interpretation of the criteria, Consumers Energy has determined that 17 sites now meet the definition of critical and therefore require enhanced security upgrades as defined by the TSA. This increases the Company's number of critical facilities requiring enhanced physical security controls as well as additional compliance oversight costs. The total projected capital cost of these upgrades is $1.87 million in 2023, and an additional $6 million for 2024 and 2025 as detailed in the business case titled "12443 TSA Critical Facility Structure." Additional information on this investment can be found in the investment capital and O&M expenditures section of this testimony. The TSA continues to update guidance on criticality and more regulation of these sites can be expected.

In addition, because of the Colonial Pipeline cyber security incident, the TSA released two directives requiring immediate action from gas asset owners. The directives are in place for one year and they are renewed annually by the TSA. The TSA has stated that they plan to renew the Security Directives every year with minor revisions as they deem necessary until official Federal Rulemaking is in place for Gas Utilities. The directives require a significant number of additional security controls and processes be implemented in a very short timeframe in both the Company's corporate and operational networks.

At the state level, the MPSC has required implementation of API 1164 standard version 2 ("API1164 v3"). This multi-year implementation started in 2020 and will conclude in 2023.

Beyond the immediate items above, the industry is expecting additional mandatory cyber security standards for gas, national reporting requirements for cyber security incidents, and federal privacy legislation like what was enacted in Europe's General Data

Protection Regulations and legislation passed by many U.S. states. Finally, there are bills aimed at ransomware and critical infrastructure protections with various requirements.

On the privacy front, proposed rulemaking by the Federal Trade Commission (Trade Regulation Rule on Commercial Surveillance and Data Security), and legislation introduced at the state (H.B. 5989) and federal levels (H.R. 8152 – American Data Privacy and Protection Act) continues to collect support. If passed, these bills will impact management of customer data, necessitating standing up a formal customer data access, authentication, request, and provisioning program; a dispute resolution body and accompanying processes; as well as staffing for a thorough review, alignment, and continued operation of the Company's Customer Data Privacy Program. Unless specifically preempted by the legislation, the Company will need to work with the MPSC to align its Privacy Tariffs to eliminate conflicts and facilitate compliance with all relevant regulatory mechanisms.

SECURITY DEPARTMENT OPERATIONS O&M EXPENSES

Q. Please explain Security Department Operational O&M Expenses.

A. The Company uses Operations O&M expense to provide the required level of operational support for both physical and cyber security, maintenance for security facilities and systems to ensure system reliability, vulnerability assessments and penetration tests, and fulfillment of all state and federal laws and regulations, perimeter protection, guards, card access, cameras, executive protection, and investigative services. Operations expenses include software vendor maintenance agreements, cloud subscription contracts, annual license contracts, and technology or appliance support through managed services contracts. Software and cloud solution vendors typically increase on an annual basis. Operations costs also include labor for equipment monitoring, physical security site assessments, vulnerability and penetration test remediation, additional guard support, system break/fix or maintenance activity, privacy program maturity, staffing support to meet emerging regulatory laws and regulations, and additional security system improvements. The activities associated with the costs are required to keep the Company's physical and information assets protected and performing at sufficient levels. The Company's customers continue to benefit from the physical and cyber security activities provided by the Security Department's O&M expense. Any gap in the recovery of Operations O&M cannot be recovered in future rate case filings, which is why any disallowance is so impactful to the Company's ability to maintain and secure its facilities and systems.

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

A. There is a variety of operational work required to keep physical and information assets protected from security threats aside from fulfilling emerging regulatory requirements. First, regarding physical assets and employee safety, routine assessments must be performed on all assets and facilities to ensure proper maintenance is performed and security protections are properly placed including perimeter protection, cameras, and card readers for facility access. Second, additional security support is needed for employees when threats are present near field project work, storm restoration activities, or Company sponsored public events or forums. Third, additional security guard support is needed at facilities on an ad hoc basis (based on intelligence collected from facilities or crews, threats of violence against the Company, increased protest activity as seen in 2020, increased contractor traffic, and potential employee issues) to ensure the safety of employees and any visitors to the Company's facilities.

Regarding information assets, security tools must be kept functional on all relevant systems, including software to collect logs, look for vulnerabilities, detect intrusions, and provide antivirus and encryption services. Second, vendors regularly release security updates that then must be tested to ensure these updates do not introduce negative impacts to Company-specific configurations, and then deployed to associated information assets. Third, as cyber security best practices change, the security teams must make changes to existing security systems to meet new security requirements. These requirements evolve and adapt as threats change in our environment. Security maintains and periodically reviews and updates approximately 55 physical and cyber security standards, which increases operational costs and IT costs while continuing to best protect Company assets.

Q. How does the request for increased O&M (Operational O&M and Investment O&M) funding benchmark in the industry?

A. There are several commonly accepted methods for benchmarking security spend for an organization including security spend compared to IT spend or as a percentage of overall company revenue. The Security organization has undertaken benchmarking exercises using both measures with a private utility consortium as well as benchmarking performed internally by third parties. These activities continue to place Consumers Energy's cyber security spending at slightly lower than the median of our peers. This demonstrates the cost effectiveness of our program despite the increased regulatory requirements previously reviewed and the changing threat environment to Consumers Energy.

Q. What value will customers receive for the projected test year expenses?

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

Q. Please explain the Operational O&M expenses shown on Exhibit A-28 (BSB-3).

A. Exhibit A-28 (BSB-3) is a Summary of Actual and Projected Security Operations O&M Expense for the Years 2022, 2023, 2024, and test year 12 Months Ending September 30, 2025. Page 1 provides a summary of the gas allocation of actual and projected Security Department operational expenses. Specifically:

- Column (a) provides the Operations and O&M Expense Category;

- Column (b) identifies the 2022 historical Operations O&M expense as $4,651,000;
- Column (c) identifies the 2023 projected Operations O&M expense as $3,910,000;
- Column (d) identifies the 2024 projected Operations O&M expense as $4,384,000;
- Column (e) identifies the 3 months ending December 31, 2024 projected Operations O&M expense as $1,099,000;
- Column (f) identifies the 9 months ending September 30, 2025 projected Operations O&M expenses as $3,285,000;
- Column (g) identifies the 12 months test year projected Operations O&M expense as $4,384,000;
- Column (h) identifies the 2025 projected Operations O&M expense as $4,219,000; and
- "Labor" line items include employee labor, and "contracts" line items include hardware and software licenses and maintenance, staff augmentation, the Company's managed services contract, and other contracted services.

Page 2 presents the amounts of the projected Operations O&M expenses that were developed by applying either an inflation rate or other adjustments (see next section for description) to historical O&M expense. Specifically:

- Column (a) is a description of the categorical expense;
- Column (b) provides the historical O&M expense;
- Column (c) provides the historical amount that an inflation rate or merit increase rate was applied to;
- Columns (e) and (g) provide the amount to which an inflation rate or merit increase rate were applied for the bridge period;
- Columns (d), (f), and (h) provide the merit and inflation increases for each respective period;
- Column (i) includes amounts that were projected using other methods; and
- Column (j) provides the projected test year Operations O&M and is the sum of columns (b), (d), (f), (h), and (i).

Q. Please describe the Other Adjustments indicated in Exhibit A-28 (BSB-3), page 2.

A. Security does not apply inflation in all categorical spend projections for Operations O&M expense. The test year Operations O&M projection is adjusted by $412,000 for anticipated reduction in headcount and focused review of the Security Plant Maintenance ("SPM") budget. Security industry standards for hourly rate averages have been used to project the headcount costs. Inflation is not used to project any other categorical spend projections for Operations O&M expense.

Future contract expenses are projected based on annual increases for current technology investment commitments for ongoing contracted maintenance and support expenses. Also included in future contract expenses are the addition of new contracts required for ongoing and new technology investment implementations before or during the test year period. These expenses are needed for operational maintenance and support. A credit is included in the test year labor projections for contracts due to the ability to reduce security guard contracted services that will be assumed by the additional Fusion Center resources. Additional savings in Contracts have been realized via focused review of the SPM budget to realize savings with MS Azure and other contracted products. This allows the Company to save money over the longer term. Business Expense is projected based on historical spend and known adjustments for employee training needs, wireless plans, and supplies required to support remote work, skill up employees who will operate new technology investments, or to develop new capabilities. The adjustments are an average per person allocated amount determined at the beginning of each year. The other adjustments for material include projected decreases due to efficiencies gained from a new virtual working environment and revised business practices implemented because of the COVID-19 pandemic.

Q. Please describe the projected Security Department Operations O&M expense for 2023 and 2024.

A. The 2023 projected Operations O&M expense is $3,910,000 and the projected Operations O&M expense for 2024 is $4,384,000. Operations O&M expense decreased from 2022 to 2023 due to contract decreases identified through cost optimization efforts. Labor decreases were identified through the Company sponsored Voluntary Separation Program. O&M expenses are projected to increase to planned levels in 2024. However, it is not anticipated that the O&M expenses will change after 2024. The Security Department intends to keep the staffing levels constant through 2025.

Q. Please explain why the Company needs 24/7 security coverage.

A. Cyberattacks have evolved significantly in recent years regarding their speed to execution. Historically, an attacker would have been in a technology environment for weeks, up to months, to execute a large-scale data breach. Given that, historically, the Company felt confident in its ability to detect and respond to such attacks using a traditional workday coverage model. Ransomware has completely changed this model.

Ransomware attacks are being fully executed, from initial access to full environment encryption, in hours (encryption is a way of scrambling data so that only authorized parties can understand the information). Industry sources suggest that "The speed of ransomware groups is also startling, with 56% saying ransomware actors managed to take over their data and send a ransom demand in under 12 hours." In addition, according to FireEye, 76% of all ransomware infections in the enterprise sector occur outside working hours, with 49% taking place during nighttime over the weekdays, and 27% taking place over the weekend. The pace at which ransomware executes, coupled with the criticality of the services the Company provides to its customers (life safety services such as gas leaks and downed wires), necessitates an investment beyond the current operational model. The Company must have staff monitoring and responding 24/7. In addition, 24/7 coverage is the standard for the utility industry. After benchmarking across industry peers, the Company found they had moved to 24/7 cyber security monitoring. While there is a cost to move to 24/7 cyber monitoring, the Company is combining both physical and cyber monitoring into a single function to be cost effective. This single function is the Fusion Center, which was initially included in a previous electric rate case filing (Case No. U-20134) as an investment that included the build out of the Fusion Center facility and technology. Previous requests in Gas Rate Case No. U-21148, and Electric Rate Case No. U-21224, in addition to this case, are for staffing of the Fusion Center.

Of the Company's utility peer group, 75% are currently operating a 24/7 cyber security monitoring function. Historically, the Company has felt it was not required because major attacks, such as a data breach, have taken weeks to months to complete and there was time to catch them without 24/7 monitoring. However, ransomware attacks are occurring within hours and are driving the Company's need for 24/7 cyber security monitoring. The O&M labor increase sought in this case focuses on staffing the Fusion Center that will provide 24/7 monitoring which combines both cyber and physical security monitoring.

With the potential passage of: (1) federal legislation; (2) several individual bills in states that may implicate Michigan-based businesses necessitating regulatory tracking and business response; and/or (3) State of Michigan legislation, the Company stands ready to leverage the Fusion Center. Fusion Center staff will automate real-time tracking and will monitor, 24/7, the data flowing into and out of the Company to immediately identify and stop transmission of information sharing prohibited by such regulations. Privacy staff in the Fusion Center will also manage increased Data Subject Request demand, adhering to maximum turnaround times.

Q. Please explain why the Company is proposing to use more cloud/SaaS based security products.

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

In addition to the industry drivers, there are benefits to both the Company and customers. More SaaS means fewer large capital outlays for large hardware purchases, vendor integrations, and less asset refresh cost. The Company anticipates fewer large capital projects in its future year planning for cyber security as capital requests have reduced, while physical security requests are increasing. Finally, using SaaS allows the

Company to receive the best security capability available and allows vendors to adapt to changes much more quickly than on-premise solutions.

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

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

<u>SECURITY DEPARTMENT INVESTMENTS O&M EXPENSES</u>

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

A. Investments O&M is used by the Company to fund the O&M portion of security technology upgrade projects, asset refresh projects, and technology investments to provide new capabilities for internal security operations to protect the Company's assets, employees, and customers. The O&M portion of upgrade projects makes up activities such as training that, according to Federal Energy Regulatory Commission ("FERC") accounting rules, cannot be categorized as capital work.

Q. Please describe the importance of upgrading Security systems for operational stability and mitigation of security vulnerabilities.

A. Upgrading security devices such as cameras and card readers, in addition to applications, appliances, and operating systems, is essential to delivering safe, reliable, and affordable service to the Company's customers. New versions of technology and software upgrades enable the Company to maintain vendor support, remediate security vulnerabilities, address defects that impair stability and functionality, and address version interdependencies and compatibility between systems.

Q. What could happen if the Company did not keep its security devices and systems upgraded?

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

Q. Please explain Exhibit A-29 (BSB-4).

A. Exhibit A-29 (BSB-4) is a Summary of Actual and Projected Security Investments O&M Expense for the Years 2022, 2023, 2024, and test year 12 Months Ending September 30, 2025. Page 1 provides a summary of the gas allocation of actual and projected Security Department Investments O&M Expenses. Specifically:

- Column (a) provides the Investments O&M expense category;
- Column (b) identifies 2022 historical Total Investments O&M expense as $734,000;
- Column (c) identifies the 2023 projected Total Investments O&M expense as $743,000;
- Column (d) identifies the 2024 projected Total Investments O&M expense as $487,000;
- Column (e) identifies the three months ending December 31, 2024 projected Total Investments O&M expense as $122,000;

- Column (f) identifies the nine months ending September 30, 2025 projected Total Investments O&M expense as $457,000;
- Column (g) identifies the test year projected Total Investments O&M expense as $579,000;
- For Investment Planning expense, "Labor" line items include employee labor, and "contracts" line items include hardware and software licenses and maintenance, staff augmentation, and other contracted services; and
- For Investments expense, "Labor" line items include employee labor, "software" line items include software licenses and maintenance contracts, "material" line items include hardware purchases and maintenance contracts, "Contractor Costs" line items include staff augmentation, managed services, and other contracted services, and "Overhead and Others" line items include overheads and business expenses.

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

- Column (a) is a description of the categorical expense;
- Column (b) provides the historical Investment O&M expense;
- Column (c) provides the historical amount to which inflation rate or merit increase was applied;
- Columns (e) and (g) provide the amounts to which an inflation rate or merit increase rate was applied for each bridge period, respectively;
- Columns (d), (f), and (h) provide the merit and inflation increases for each respective period;
- Column (i) includes amounts that were projected using other methods; and
- Column (j) provides the projected test year investments O&M and is the sum of columns (b), (d), (f), (h), and (i).

Q. Please describe the Other Adjustments indicated in Exhibit A-29 (BSB-4), page 2.

A. Security does not apply inflation for categorical spend projections for Investments Planning expense. The investments planning projection is adjusted by $6,000 for anticipated increases in the test year for investments planning activities that directly support business case development and cost estimate refinement for projects that support the Company's

Security Department purpose and other Company long-term plans. Inflation is also not used to project future Investments O&M expense. The other adjustments for Investments O&M expense are based solely on expected project costs for the test year as compared to the historical period, as detailed in Exhibit A-27 (BSB-2).

SECURITY DEPARTMENT INVESTMENTS CAPITAL EXPENDITURES

Q. Please explain the capital expenditures shown on Exhibit A-12 (BSB-1), Schedule B-5.2.

A. Exhibit A-12 (BSB-1), Schedule B-5.2, identifies the gas allocation summary of actual and projected capital expenditures to procure, install, and implement the software and infrastructure described in this testimony to fulfill the Company's Security Department purpose to Deter, Detect, Comply, Recover, and Enable. Specifically,

- Column (a) provides the program designation for the capital expenditures, using programs that have been used historically to categorize Security Department projects:
  - Enhancements; and
  - Security.
- The exhibit provides historical and projected capital expenditures as follows:
  - Column (b) identifies 2022 historical year total capital expenditures as $6,908,000;
  - Column (c) identifies the 12 months ending December 31, 2023 projected total capital expenditures as $6,589,000;
  - Column (d) identifies the 9 months ending September 30, 2024 projected total capital expenditures as $4,224,000;
  - Column (e) identifies the 21 months ending September 30, 2024 projected bridge period total capital expenditures as $10,812,000; and
  - Column (f) identifies the 12 months ending September 30, 2025 projected test year total expenditures as $4,786,000.

- The lower portion of the exhibit also divides these same expenditures into the following periods: 9 months ending September 30, 2023; 12 months ending September 30, 2024; 12 months ending September 30, 2025; and 33 months ending September 30, 2025.

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

Q. Please explain Exhibit A-27 (BSB-2).

A. Exhibit A-27 (BSB-2) identifies the gas allocation of projected capital and O&M costs to procure, install, and implement software and infrastructure requested in this testimony to meet the Security Department's purpose. Security technologies are all about risk avoidance. Because of this, it can be difficult to establish a cost/benefit ratio when it is not possible to quantify the costs of risks that do not occur from security incidents that do not happen because of the technologies or capabilities implemented. For this reason, the security industry does not typically see cost savings because of investments. Both O&M and capital are required to complete the projects included in the test year. This exhibit provides details regarding all projects included in this rate case filing for the Security Department. Specifically, within this exhibit:

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

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

<u>DESCRIPTION OF INVESTMENT PROJECTS</u>

Q. Do the Company's total Security capital projections reflect a 20% reduction for those projects whose projections are based on a Rough Order of Magnitude ("ROM") estimation process?

A. Yes. Despite ROM cost-cutting concerns, the total capital projections include a 20% reduction for those projects whose projections are based on a ROM. In order to prevent over recovery, a 20% ROM adjustment is calculated by program for those projects with a

ROM estimate with the expectation that the full costs of approved projects may be recovered in a future rate case. These reductions are included in the table below and further reflected in Exhibit A-27 (BSB-2).

Year	Projected	Adjusted Projected (20% ROM Adjustment)
2022	$6,908,474	$6,908,474
2023	$6,961,854	$6,588,649
2024	$6,766,432	$5,631,666
2025	$5,249,825	$4,504,574
Test Year	$5,628,977	$4,786,347

Q. Please provide a description of the various Security Department investment projects.

A. The Security Department investment projects are listed below along with their synopsis and high-level cost information. Additional cost information, alternatives, and other relevant project information for each individual project can be found in Exhibit A-27 (BSB-2).

Physical Security – Asset Refresh:

- **Description:** This project will enhance or replace physical security assets to provide improved visibility and incident resolution related to security concerns.
- **Problem Statement:** The Company has several thousand physical security asset devices currently in use including security cameras, motion detectors, intrusion detection systems, and card access systems. Current limitations include the lack of integrated solutions for centralized management, situational awareness, real time monitoring, compliance with regulations and guidelines, and faster responses to emergencies and incidents. This could result in the increase of potential security vulnerabilities, associated penalties, and reputational damage.
- **Objectives:** (1) Maintain compliance with State and Federal Regulations, (2) reduce redundancies by decreasing multiple camera dependencies and reducing gaps in functionality, and (3) optimize overall system performance.
- **Scope:** Included in the project is the enhancement or replacement of assets including: (1) advanced door systems at Company buildings, (2) security

cameras for monitoring capabilities, and (3) gate and lock systems, which include security cameras, motion detectors, intrusion detection systems, and card access systems.

- **Alternatives Considered:** (1) Do not refresh physical security assets, and (2) defer a portion of the refresh of physical security assets per asset refresh cycle industry standard. Alternatives 1 and 2 were not selected due to the risk of security concerns, incident resolution, and the inability to meet FERC requirements. The alternative that was selected maintains compliance, reduces redundancies and gaps in functionality, and optimizes overall performance of physical security systems.

Enhancements – Capital and O&M:

- **Description:** This initiative will use Capital funding to make enhancements to existing technology and to address requests generated by changing business requirements. O&M is included within this project to complete expense activities associated with Capital enhancements in accordance with accounting rules.

- **Problem Statement:** As business conditions improve and change, compliance requirements evolve, and new capabilities are needed. New requirements surface that call for smaller effort software application changes (enhancements). Enhancing applications requires a short timeframe between inception and implementation and cannot and should not wait for rate case approval at an individual line-item level. Failure to make these changes to applications can have a direct negative impact on key customer and business processes, increase support costs, limit the Company's ability to consistently meet objectives, and increase security risk.

- **Objectives:** (1) Enhance security protections by funding emerging or unplanned cyber security activities resulting from audits, incidents, or a changing threat landscape; (2) reduce the number of incidents associated with outdated software; (3) increase application stability, leading to fewer incidents due to outdated software; and (4) enable the Company to leverage additional functionality available in the technology.

- **Scope:** (1) Make necessary system changes, and (2) update documentation related to the changes. Enhancement requests are fulfilled to provide functionality for areas such as cyber security related platforms, cyber security incident response, physical security, security awareness, risk management, privacy, and compliance.

- **Alternatives Considered:** Prior to implementing an enhancement, a review is completed to identify the best solution. During that review, requests for this funding are governed by a cross-functional board that routinely evaluates and prioritizes the work. Security enhancements fortify the Company's ability to make software technology changes as part of process improvements and regulatory changes and to meet legally required system changes in a fast and nimble manner. Without funding for enhancements, the Company will be limited in its ability to quickly provide needed capabilities and improvements.

Application Currency – Capital and O&M:

- **Description:** This Security initiative will utilize both Capital and O&M funding to keep applications current for security and reliability. O&M is included in this project to complete expense activities associated with Capital upgrades.

- **Problem Statement:** The Company manages a large number of applications in the technology landscape that require regular version upgrades to maintain vendor-supported software versions. Without vendor supported versions, the Company loses the ability to receive version updates and upgrades to address defects, patch security vulnerabilities, protect against cyber threats, protect data, and add new features. Failure to upgrade these applications can have a direct negative impact on key customer and business processes, increase support costs, increase unplanned outages, and increase cyber security vulnerabilities.

- **Objectives:** (1) Enable the Company to maintain vendor support, (2) remediate vendor security vulnerabilities and enhance security protections, (3) address vendor defects that impair stability and functionality, leading to fewer incidents due to outdated software, (4) address version interdependencies and compatibility between systems, and (5) enable the Company to leverage new functionality available in the upgrades. This is essential to delivering safe, reliable, and affordable service to the Company's customers.

- **Scope:** The application upgrades in scope are regularly prioritized based on considerations that include application criticality, number of versions behind the current available version, security and operational risk, operational impacts of performing the upgrade, ability to defer, and cost. The scope of upgrading these applications encompasses: (1) upgrading the application software, (2) assessing any new functionality for value to the Company, (3) making necessary configuration changes, (4) testing the upgraded software, and (5) updating documentation related to the integration changes. Applications within the Security portfolio are routinely evaluated to determine if and what upgrade efforts are necessary to maintain an appropriate level of currency, as well as the priority of those efforts.

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

Asset Refresh – Cyber Security:

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

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

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

- **Scope:** This project will (1) annually replace a subset of cyber security firewalls and servers in keeping with a three- to five-year hardware lifecycle, and (2) perform application upgrades.

- **Alternatives Considered:** The alternatives considered were: (1) upgrade or replace assets needing to be upgraded or replaced based on dates provided by the manufacturer, or (2) upgrade or replace a portion of the assets identified in the plan. Option 1 was not chosen based on a continued refresh cycle for cyber security assets to avoid security risks, system vulnerabilities, and out-of-warranty repair costs. Option 2 was not chosen due to the security risk inherent with not replacing assets as per established standard refresh cycles enabling increased system vulnerabilities and out-of-warranty repair costs.

Saviynt, Access Now Replacement:

- **Description:** This project will implement Saviynt in lieu of upgrading Access Now, in addition to the proposed HR Process Integration, providing an Identity Access Management ("IAM") solution as well a replacement for antiquated HR process integrations.

- **Problem Statement:** Access Now, the existing solution that Saviynt will replace, is highly customized and requires extensive professional services for operational support, enhancements, and projects, and the version currently in use is no longer supported by the vendor. A primary Access Now component, IAM, exists in several other tools used by the Company creating wasteful redundancy. Finally, antiquated HR processes used by the Company introduce technology failure points, delays, and data integrity issues with operational, compliance, and regulatory processes.

- **Objectives:** This project will create value as it will (1) eliminate costly and ongoing professional services supporting Access Now, (2) eliminate customization, redundant tools, infrastructure, and infrastructure support, (3) improve the portal for intuitive end user experience and streamlined support, and (4) improve Sarbanes Oxley Act of 2022 compliance through automation. Regarding HR functionality, it will (5) automate manual HR processes, (6) reduce incidents and improve compliance through automation, and (7) allow for retirement of custom-built HR applications.

- **Scope:** This project will (1) implement and configure Saviynt Enterprise Identity Governance and Administration ("EIGA"), (2) implement 112 IAM use cases, (3) retire Access Now, (4) implement HR interface for employee data processing, (5) retire IT Security Database Application, and (6) train key stakeholders, systems administrators, and operations on how to properly use the system.

- **Alternatives Considered:** Alternatives considered include (1) implement ongoing last-minute fixes to Access Now to ensure support, (2) upgrade only the application to current supported version, (3) implement IAM functions in Saviynt platform to manage access requests, including Active Directory, SAP, SAP HR, and disconnected systems as well as existing API integrations, and (4) remain on the current version that will be unsupported as of Jan 2024.

Badge Reader/Lock and Key Management:

- **Description:** This project will implement a physical smart lock and key management system throughout the Company's Electric service territories. Lack of key control makes facilities, specifically in Electric operations, vulnerable to accidental or intentional disruption to power supply which could cause large scale outages. Install badge readers, smart locks, and credentials on smart devices to grant access to electric assets.

- **Problem Statement:** Current estimates show there are approximately 12,000 locks throughout the state, and the Company does not have a system to properly manage ownership of the associated physical keys or control over who uses the keys. Locks are not unique in nature and can be easily duplicated. Today's lock and key system allows for 24-hour site access without having the ability to limit outside contractor access. Lack of key control makes facilities, specifically in Electric operations, vulnerable to accidental or intentional disruption which could cause large scale outages.

- **Objectives:** Completion of this project will provide value to the Company by: (1) providing an extra layer of protection which is our first defense against criminal acts; (2) determining core functionalities needed to ensure proper lock and key management state-wide for gas operations; (3) implementing a smart lock and key solution that will provide the physical security team remote deactivation capabilities and is easily audited. (4) Install a smart lock system; and (5) Leverage credentials on mobile device and badge readers that can read both physical cards and digital applications.

- **Scope:** The scope of this project includes: (1) a determination of the different levels and functions of different smart lock systems available for electric facilities; and (2) purchase and implementation against a site plan of a lock and key management system specific for needs of Electric Operations.

- **Alternatives Considered:** Alternatives considered include: (1) Continue to use current Corbin locks with no key control; (2) utilize badge readers that cannot read a digital badge.

Security Threat Intelligence Tool:

- **Description:** The project will implement a threat intelligence tool that will actively assess threats in our environment, visually display historical and active threat data for situational awareness and provide alerts to employees based on location to the threat. This information would allow the security operation center to inform employees who are traveling on the risks they may face; help inform decisions on hardening facility locations and prevent sending employees into areas with an active threat.

- **Problem Statement:** Consumers Energy's Security team currently does not have the ability to actively collect or disseminate threat intelligence. Threat intel for the following categories has historically not been able to be gathered to facilitate proactive response. This increases the security risk to employees and assets. As the threat landscape changes, automating data collection is essential to detecting and determining threats in real time. Our current 24/7 Security Operation center manually searches through sources to collect threat intelligence. This re-active approach has led to gaps in information and the inability to accurately depict the threat environment.

- **Objectives:** The object of this project is to implement a threat intelligence tool that will actively assess threats in our environment, visually display historical and active threat data for situational awareness and provide alerts to employees based on location to the threat. Accurate and timely information about threat actors and their tactics enables the team to proactively perform targeted investigation, containment, and remediation.

- **Scope:** This project would allow the Consumers Energy Security team to actively gather and disseminate information and provide actionable intelligence for both physical and environmental threats including but not limited to; attacks to critical infrastructure including substations, generation facilities and gas assets, hostile activists, acts of violence, protests, workplace violence, targeted threats to executives, accidents, severe weather, natural disasters, public health, chemical spills, and terrorist activity. This information would allow the security operation center to inform employees who are traveling on the risks they may face; help inform decisions on hardening facility locations and prevent sending employees into areas with an active threat.

- **Alternatives Considered:** Maintain our current security posture of manually gathering information on threats through social media, law enforcement or news reports. Only alert employees of active threats once they are noticed by Security operation center analysts. Consumers Energy's Mass notification tool, Everbridge, is up for renewal in 2025 and will be reviewed as an alternative to fulfill this business case scope.

TSA Critical Facility Structure

- **Description:** This project will implement enhanced security measures outlined by the TSA for critical facility assets in order to bring the locations up to enhanced status and avoid non-compliances. This project will increase the security and reliability of gas delivery to our customers while also meeting federal requirements.

- **Problem Statement:** Pipeline facilities that are deemed critical are required to apply enhanced security measures. Today, Consumers Energy currently has designated four locations as critical. However, based on the April 2021 update to the TSA Pipeline Security Guidelines, Section 5 (Critical Facility Criteria), a significant number of our gas infrastructure that were not previously subject to evaluation will now fall into scope. As we continue to analyze the remainder of our gas assets, we believe an additional 1000 pipeline facilities (pipeline interconnections, metering and/or regulating stations, pump stations, compressor stations, operational control facilities, main line valve, tank farms and terminals, etc.) may be deemed critical. Consumers Energy will be taking a phased implementation approach and will begin the process by implementing the enhanced security measures at the reminder of our compressor stations. Failure to update our sites will put us out of compliance with the updated guidelines.

- **Objectives:** The objective of the project is to implement enhanced security measures outlined by the TSA for the following four critical assets: (1) Freedom Compressor, (2) Muskegon River Compressor, (3) Overisel Compressor, and (4) Northville Compressor. The measures applied will bring these locations up to Enhanced status and avoid non-compliances. This project will increase the security and reliability of gas delivery to our customers while also meeting federal requirements.

- **Scope:** Enhanced Security measures that will need to be implemented include, but are not limited to: (1) access controls; (2) access readers; (3) cameras; (4) video and audio programming; (5) fencing and barriers; (6) gates; (7) locks and key control; (8) fence intrusion (which may be accomplished with a new camera system); (9) subcontractor work of trenching poles, etc.; (10) facility lighting; (11) background Investigations for personnel working at the site; (12) security equipment maintenance and testing; (13) security vulnerability assessments; (14) security communication plans; (15) personnel training; (16) security drills and exercises for the following locations. These activities will be performed at the following company locations: Overisel, Freedom, Northville, and Muskegon River.

- **Alternatives Considered:** Alternatives are not available because this is a compliance mandate from the TSA.

Q. Please explain the investment projects enabling physical security along with how the capital and O&M costs were derived.

A. The summary table below defines physical security investment projects with direct ties to enabling physical security. Cost, descriptions, benefits, alternatives, and other relevant project information can be found in Exhibit A-27 (BSB-2).

Investment	Test Year O&M	Software	Material	Labor	Contractor Costs	Overhead & Others
Badge Reader/Lock and Key Management System	$52,910	$0	$16,280	$29,600	$0	$7,030
TSA Critical Facility Structure	$100,000	$0	$0	$80,000	$0	$20,000

Investment	Test Year Capital	Software	Material	Labor	Contractor Costs	Overhead & Others
Badge Reader/Lock and Key Management System	$758,750	$0	$75,875	$151,750	$493,187	$37,937
TSA Critical Facility Structure	$2,500,000	$0	$1,250,000	$250,000	$1,000,000	$0

The Badge Reader/Lock and Key Management System project implements a physical smart lock and key management system throughout the Company's service territory. Locks are not unique in nature and can be easily duplicated. Today's lock and key system allows for 24/7 site access without having the ability to limit outside contractor access. Lack of key control makes facilities vulnerable to accidental or intentional disruption which could cause large scale outages.

The TSA Critical Facility Structure project will implement enhanced security measures outlined by the TSA for critical facility assets to bring the locations up to enhanced status and avoid non-compliances. This project will increase the security and reliability of gas delivery to customers while also meeting federal requirements.

Q. Please explain the investment projects enabling cyber security along with how the capital and O&M costs were derived.

A. The summary table below identifies security investment projects with direct ties to enabling cyber security. Cost, descriptions, benefits, alternatives, and other relevant project information can be found in Exhibit A-27 (BSB-2). The Company is planning both capital and O&M for its investment projects enabling cyber security.

Investment	Test Year O&M	Software	Material	Labor	Contractor Costs	Overhead & Others
Saviynt EIGA Implementation	$143,375	$0	$0	$114,700	$0	$28,675
Security Threat Intelligence Tool	$5,550	$0	$0	$2,775	$0	$2,775

Investment	Test Year Capital	Software	Material	Labor	Contractor Costs	Overhead & Others
Saviynt EIGA Implementation	$842,213	$121,400	$0	$265,563	$303,500	$151,750
Security Threat Intelligence Tool	$573,615	$573,615	$0	$0	$0	$0

The Security Threat Intelligence project will implement a threat intelligence tool that will actively assess threats in the environment, visually display historical and active threat data for situational awareness and provide alerts to employees based on location to the threat. This information would allow the security operation center to inform employees who are traveling on the risks they may face, help inform decisions on hardening facility locations, and prevent sending employees into areas with an active threat.

The Saviynt project will implement Saviynt EIAG module, consolidate IAM functionality into Saviynt, and retire AccessNow application. The benefits of this project will enable security to manage access (identities) more effectively and efficiently across the environment by addressing issues of aging software, multiple identity management tools, and antiquated integrations with other systems.

Q. Please identify the annual security programs along with how the capital and O&M costs were derived.

A. The summary table below defines security investment projects that are considered in scope for annual security programs. Cost, descriptions, benefits, alternatives, and other relevant project information can be found in Exhibit A-27 (BSB-2). The Security team is planning both capital and O&M costs for its Asset Refresh, Enhancement, and Application Currency annual programs.

Investment	Test Year O&M	Software	Material	Labor	Contractor Costs	Overhead & Others
Asset Refresh Program - Cyber Security	$9,250	$0	$0	$9,250	$0	$0
Physical Security Asset Refresh	$3,700	$0	$0	$1,776	$1,480	$444
Application Currency-Security-Capital	$3,700	$0	$0	$2,960	$0	$740
Application Currency-Security-O&M	$22,138	$0	$0	$17,710	$0	$4,428
Enhancements-Security-Capital	$14,800	$0	$0	$11,840	$0	$2,960
Enhancements-Security-O&M	$215,842	$0	$0	$177,102	$0	$38,741

Investment	Test Year Capital	Software	Material	Labor	Contractor Costs	Overhead & Others
Asset Refresh Program - Cyber Security	$208,755	$0	$139,170	$55,668	$0	$13,917
Physical Security Asset Refresh	$481,770	$0	$303,500	$32,590	$136,575	$9,105
Application Currency-Security-Capital	$29,319	$0	$0	$23,249	$0	$6,070
Application Currency-Security-O&M	$0	$0	$0	$0	$0	$0
Enhancements-Security-Capital	$234,555	$0	$0	$185,995	$0	$48,560
Enhancements-Security-O&M	$0	$0	$0	$0	$0	$0

For Asset Refresh programs, prior to the hardware no longer being supported by the vendor and/or manufacturer, the Company revisits its use cases to determine what success looks like for the given technology. At this time, the Company may evaluate newer technology from other vendors and create a proof of concept to see which one meets the Company's use cases best. As a part of this analysis, the Company requests budgetary quotes to evaluate against business needs and determine which brings the best value. Depending on the solution, the Company may receive multiple bids but typically vendors work through a Value Added Reseller, which provides the best discounts.

Enhancement work typically involves improvements to platforms or solutions the Company already owns, such as turning on additional features and improving processes via automation. As a part of the enhancement process, the Company identifies the scope along with success criteria it is trying to achieve, identifies any additional costs and resources needed, and determines a budgetary quote for consideration.

Application Currency program is maintained by the Company for the purpose of applying version upgrades to software based on the following reasons: Maintaining Vendor Support, Remediating security vulnerabilities, Addressing vendor defects that impair stability and functionality, Addressing version interdependencies and compatibility between systems; and Allowing the Company to leverage new functionality available in the upgrades. As a part of the Application Currency process, upgrades are planned and reviewed for potential capital requirements through a capital policy request.

Q. Does this conclude your direct testimony?

A. Yes.

S T A T E O F M I C H I G A N

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the application of	)	
CONSUMERS ENERGY COMPANY	)	
for authority to increase its rates for the	)	Case No. U-21490
distribution of natural gas and for other relief.	)	
	)	

DIRECT TESTIMONY

OF

MARC R. BLECKMAN

ON BEHALF OF

CONSUMERS ENERGY COMPANY

December 2023

Q. Please state your name and business address.

A. My name is Marc R. Bleckman, and my business address is One Energy Plaza, Jackson, Michigan 49201.

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

A. I am employed by Consumers Energy Company ("Consumers Energy" or the "Company") as the Executive Director of Financial Planning and Analysis.

Q. What are your current responsibilities?

A. My responsibilities include preparation of the monthly forecasts, annual budgets, and long-term financial plans for Consumers Energy and CMS Energy, the parent company of Consumers Energy. As a part of my role, I conduct financial analyses and studies required for making various strategic decisions such as equity issuance, sale of businesses, and new investments. I assist the Chief Financial Officer in preparing the presentations for Board of Directors meetings, quarterly earnings calls, investor meetings, and industry conferences. My responsibilities also include preparation of the Renewable Energy Plan ("RE Plan") forecast model, which is a responsibility I have continued to assume from a previously held position.

Q. Please describe your educational background and describe any positions held prior to your current position.

A. I received a Master of Business Administration Degree with a Finance concentration from the Katz Graduate School at the University of Pittsburgh in 2002. Upon receiving this degree in May 2002, I joined Ford Motor Company ("Ford") as a Financial Analyst. During my seven years of employment at Ford, I worked in various finance roles throughout the company, including Assembly Operations, Powertrain Operations, Ford

Motor Credit, and the General Auditor's Office. My responsibilities within these organizations included, but were not limited to, forecasting of and variance reporting on, all Income Statement and Balance Sheet line items, as well as business process auditing. In July 2009, I left Ford to join Consumers Energy as a Principal Financial Analyst in the Company's Risk, Strategy, and Financial Advisory Services group. My responsibilities in this role included, but were not limited to, supporting the financial analysis and forecasting of the Company's renewable energy development plans, as well as conducting the Company's Enterprise Risk Management Program. In September 2012, I took on the role of Manager of Earnings Analysis in the Company's Financial Planning and Analysis Group. I assumed my current position as the Executive Director of Financial Planning and Analysis in February 2016.

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

A. Yes. I provided testimony in:

- Case No. U-16543, the Company's 2011 Application to Amend the RE Plan;
- Case No. U-16581, the Company's 2011 Application for biennial review of the RE Plan;
- Case No. U-17301, the Company's 2013 Application for biennial review of the RE Plan;
- Case No. U-17752, the Company's 2015 Application to Amend the RE Plan;
- Case No. U-17792, the Company's 2015 Application for biennial review of the RE Plan;
- Case No. U-18231, the Company's 2017 Application for biennial review of the RE Plan;
- Case No. U-20322, the Company's 2018 Gas Rate Case;
- Case No. U-20483, the Company's RE Plan reconciliation proceeding for 2018;

- Case No. U-20650, the Company's 2019 Gas Rate Case;
- Case No. U-20697, the Company's 2020 Electric Rate Case;
- Case No. U-20722, the Company's RE Plan reconciliation proceeding for 2019;
- Case No. U-20963, the Company's 2021 Electric Rate Case;
- Case No. U-20984, the Company's RE Plan amendment proceeding for 2021;
- Case No. U-21009, the Company's RE Plan reconciliation proceeding for 2020;
- Case No. U-21148, the Company's 2021 Gas Rate Case;
- Case No. U-21197, the Company's RE Plan reconciliation proceeding for 2021;
- Case No. U-21224, the Company's 2022 Electric Rate Case;
- Case No. U-21308, the Company's 2022 Gas Rate Case;
- Case No. U-21352, the Company's RE Plan reconciliation proceeding for 2022;
- Case No. U-21374, the Company's Application for approval of revised Voluntary Green Pricing programs and a RE Plan amendment; and
- Case No. U-21389, the Company's 2023 Electric Rate Case.

Q. What is the purpose of your direct testimony?

A. The purpose of my direct testimony is to present my recommendations regarding the capital structure and cost of capital which should be used in computing the overall rate of return for Consumers Energy.

Q. How is your direct testimony organized?

A. My direct testimony is organized as follows:

I. <u>SUMMARY OF RECOMMENDATIONS</u>

II. <u>CAPITAL STRUCTURE AND COST RATES</u>

A. <u>Development of Capital Structure</u>

B. <u>Development of Cost Rates</u>

III. EXHIBITS FOR CERTAIN FILING REQUIREMENTS – CREDIT RATINGS AND RECENT UTILITY BOND ISSUANCES

IV. PROJECTED CASH BALANCE

V. SUMMARY AND CONCLUSIONS

Q. Are you sponsoring any exhibits?

A. Yes. I am sponsoring the following exhibits:

Exhibit A-14 (MRB-1)	Schedule D-1	Overall Rate of Return Summary;
Exhibit A-14 (MRB-2)	Schedule D-1a	Capital Structure Development;
Exhibit A-14 (MRB-3)	Schedule D-1b	Comparison of Development of Capital Structure;
Exhibit A-14 (MRB-4)	Schedule D-2	Cost of Long-Term Debt;
Exhibit A-14 (MRB-5)	Schedule D-3	Cost of Short-Term Debt;
Exhibit A-14 (MRB-6)	Schedule D-4	Cost of Preferred Stock;
Exhibit A-14 (MRB-7)	Schedule D-6	Short-Term Debt Utilization;
Exhibit A-30 (MRB-8)		Current and Historical Credit Ratings;
Exhibit A-31 (MRB-9)		Recent Utility Corporate Bond Issuances;
Exhibit A-32 (MRB-10)		Peer Company Commission Authorized Equity Ratios;
Exhibit A-33 (MRB-11)		State Regulatory Evaluations;
Exhibit A-34 (MRB-12)		Moody's Investors Service May 10, 2021 Credit Opinion;
Exhibit A-35 (MRB-13)		S&P January 23, 2023 Report: Industry Top Trends – North America Regulated Utilities;
Exhibit A-36 (MRB-14)		S&P January 27, 2021 Credit Opinion; and
Exhibit A-133 (MRB-15)		UBS May 10, 2023 Report.

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

A. Yes.

I. SUMMARY OF RECOMMENDATIONS

Q. What capital structure are you recommending be utilized in the overall rate of return calculation?

A. I am recommending that the capital structure shown on page 1 of Exhibit A-14 (MRB-1), Schedule D-1, be used in this case. This represents the actual capital structure as of December 31, 2022, adjusted for the projected changes in debt, equity, deferred income taxes, and Investment Tax Credit ("ITC") through the end of the test year ending on September 30, 2025. The development of the capital structure on a ratemaking basis is shown in columns (b) through (d). The equity ratio as a percentage of permanent capital is 51.50%. The equity ratio as a percentage of total capital is 42.73%.

Q. What Return on Equity ("ROE") are you assuming to determine the overall cost of capital for Consumers Energy?

A. I am assuming an ROE for Consumers Energy's gas business of 10.25%. This ROE is recommended by Company witness Todd A. Wehner and supported in further detail in his direct testimony.

Q. What is the overall rate of return for Consumers Energy that you recommend be used in this case?

A. I am recommending an overall rate of return of 6.20% on an after-tax basis. This overall rate of return is the result of combining the capital structure and cost rates shown on Exhibit A-14 (MRB-1), Schedule D-1, page 1. The cost of the components and the weighted cost are shown in columns (e) through (i). The overall rate of return that I am recommending is the weighted cost of the various components of the capital structure.

II. CAPITAL STRUCTURE AND COST RATES

A. Development of Capital Structure

Q. What is capital structure?

A. Capital structure refers to the amounts and mix of a company's financing components which make up the funds used for its operations and capital investment. For the Company, this includes long-term debt, common equity, preferred equity (or preferred stock), short-term debt, ITC, and deferred income taxes.

Q. What is long-term debt and short-term debt?

A. Long-term debt consists of loans that have a due date (or maturity) that is more than one year from the date of issuance. For the Company, long-term debt consists exclusively of First Mortgage Bonds. Short-term debt represents borrowings that are short-term in nature (less than one year), and includes borrowings under the Company's credit facilities, including commercial paper and intercompany borrowings, as well as the balance from the Company's renewable liability. The Company aims to finance its long-term capital (such as plant and property) with long-term debt and equity, and to finance short-term capital requirements (such as seasonal working capital needs) with short-term debt. This financing strategy is explained in more detail later in my direct testimony.

Q. What is common equity and preferred equity?

A. Equity is the net worth (assets minus liabilities) of a Company. Common equity increases with net income (retained earnings) and with equity contributions from the Company's parent, CMS Energy. Common equity decreases when the Company makes dividend distributions to CMS Energy. Preferred equity is distinguished from common equity in that there is a fixed preferred dividend rate on preferred stock. Also, preferred equity has a higher ("preferred") claim to the Company's net assets in the event of insolvency.

Q. Do taxes play a part in the capital structure?

A. Yes. Deferred taxes and ITC represent reported book taxes that, due to special Internal Revenue Service deductions, measurements, or treatments, will not have to be paid until sometime in the future. This represents a temporary "zero cost" source of funding for the Company and is included as a component of the capital structure.

Q. How did you develop the long-term debt, preferred stock, common equity, short-term debt, deferred income tax, and ITC balances in the capital structure?

A. I started with the actual balances of long-term debt, preferred stock, common equity, short-term debt, deferred income taxes, and ITC as of December 31, 2022, as shown in Exhibit A-14 (MRB-2), Schedule D-1a, page 1, column (e). I then made the adjustments shown in column (f) to arrive at the average test year balance ending September 30, 2025, in column (g) that I am recommending be used in this case.

Q. Please explain the common equity adjustment of $1.951 billion.

A. I have projected that the 13-month common equity balance for the test year will be $1.951 billion higher than the December 31, 2022 balance. The common equity adjustment of $1.951 billion consists of two components. The first is an adjustment to reflect $374 million in projected retained earnings on a weighted average basis from January 2023 through September 2025. The second is an adjustment of $1.577 billion to reflect the projected equity infusions on a weighted average basis from January 2023 through September 2025.

Q. What are retained earnings?

A. Retained earnings are a company's net income from operations and other business activities retained by the company as additional equity capital. Retained earnings are, thus, a part of stockholders' equity.

Q. Please explain the retained earnings adjustment of $374 million.

A. Since I started with the December 31, 2022 balance for common equity, it was necessary to make an adjustment to reflect the increase in the common equity balance through retained earnings that will occur on a weighted average basis through September 30, 2025.

Q. Please explain how you projected the change in Consumers Energy's retained earnings from January 2023 through December 2023.

A. For the period of January 2023 through September 2023, I relied on actual changes in regulatory retained earnings. For the period of October 2023 through December 2023, I assumed the change in retained earnings would be equal to the actual change in retained earnings for the same months in 2022.

Q. Please explain how you projected the change in Consumers Energy's retained earnings from January 2024 through the test period ending September 2025.

A. Consumers Energy has a long-standing policy of using an 80% dividend payout ratio. I assumed Consumers Energy's retained earnings rate to be $15.717 million per month, or $188.6 million per year, from January 2024 through September 2025.

Q. Please explain how you arrived at Consumers Energy's retained earnings rate of $188.6 million per year.

A. Based on Consumers Energy's Securities and Exchange Commission Form 10-K for 2022, I determined that Consumers Energy's net income for the 12-month period ended

December 31, 2022, was $943 million. I used this amount as a proxy for the future net income and assumed a dividend payout ratio of 80%. Using these assumptions, I calculated an annual retained earnings amount of $188.6 million [$943x(1-0.80)]. Exhibit A-14 (MRB-2), Schedule D-1a, page 3, shows the projected monthly retained earnings balance and calculates the 13-month average for the period ending September 30, 2025.

Q. Since the Company's projection of the average retained earnings balance for the test year in this case is based on historical results, would the Company take action under the high likelihood that actual retained earnings balances differ from this projection?

A. Yes. Assuming that the actual changes in retained earnings were either higher or lower than projected based on historical results, the Company would adjust its long-term debt issuances and/or common equity infusions to achieve a 51.50% common equity ratio. Variances of actual versus projected retained earnings balances, therefore, would not have an impact on the Company's weighted average cost of capital.

Q. What are equity infusions?

A. Equity infusions are cash investments made by CMS Energy into Consumers Energy, thereby increasing the Company's common equity balance.

Q. Why did you make a $1.577 billion adjustment for the new equity infusions in your recommended capital structure?

A. This is the amount needed to hold a 51.50% equity ratio for the test period in this case. In 2023, CMS Energy made an equity infusion into Consumers Energy of $75 million in February 2023 and an equity infusion of $400 million in May 2023. The timing and amounts of each of these 2023 infusions are consistent with the Company's filing in Case No. U-21389. In addition, CMS Energy plans to make an equity infusion of $350 million in February 2024 and plans to make equity infusions of $275 million by June 2024, $525 million by February 2025, and $500 million by June 2025. Accordingly, I reflected this in the equity balance for the test year for this case on a weighted average basis. The impact of these equity infusions on the cumulative balance is shown on Exhibit A-14 (MRB-2), Schedule D-1a, page 3. The 13-month average for the period ending September 30, 2025, is $1.577 billion. When the 13-month average for the equity infusions of $1.577 billion is combined with the 13-month average $374 million retained earnings adjustment, the increase to equity capital is the $1.951 billion shown on Exhibit A-14 (MRB-2), Schedule D-1a, page 1.

Q. How did the Company arrive at the level of expected equity infusions in this case?

A. The Company projects the amounts and timing of equity infusions needed in order to arrive at a 51.50% equity ratio on average for the test year period. In order to do this, the Company reviewed a number of factors in the instant case including the level of capital expenditures, cash flows, and deferred taxes. The Company also considered the current mix of debt and equity (equity ratio).

Q. Why are the amounts and timing of the Company's projected equity infusions important in order to arrive at a 51.50% equity ratio on average for the test year in this case?

A. The amounts and timing of the Company's projected equity infusions are important because, taken together with the projected changes in retained earnings and the projected long-term debt issuances and retirements, the Company is able to arrive at a 51.50% equity ratio for the test year in this case. As I will explain in more detail later in my direct testimony, the projected 51.50% equity ratio is justified and is critical in maintaining the Company's credit quality and financial health.

Q. Has the Company been accurate in the timing and amounts of equity infusions made compared to projections in previous rate cases?

A. Yes. As mentioned earlier in my direct testimony, the timing and amounts of each of the Company's equity infusions in 2023 were consistent with the Company's filing in Case No. U-21389. In addition:

- The timing and amount of the Company's equity infusions in 2022 were consistent with the Company's filing in Case No. U-21224;
- The timing and amounts of the Company's equity infusions in 2021 were consistent with the Company's filing in Case No. U-20963;
- The timing and amounts of the Company's equity infusions in 2020 were consistent with the Company's filing in Case No. U-20697 and Case No. U-20650; and
- The timing and amounts of the Company's equity infusions in 2019 were consistent with the Company's filing in Case No. U-20322.

Q. Have the MPSC Staff ("Staff") and intervenors proposed reductions to projected equity infusions in previous cases due to perceived inconsistency between projected and actual infusions?

A. Yes. Those reductions, however, had no evidentiary basis and were ultimately incorrect. Because the proposed reductions to the Company's projected equity infusions were artificial, they did not add value to the determination of the appropriate equity ratio for the Company.

Q. In past cases, other parties have suggested that the Commission approve a 50% equity ratio for the Company. Is this reasonable?

A. No. A 50% equity ratio would be unsupportive of the Company's current credit quality. In proposing a 51.50% equity ratio, the Company will be reducing its permanent equity ratio by 133 basis points from 52.83% at year-end 2022 to 51.50%. The projected 51.50% is also significantly lower than the 13-month average permanent equity ratio of 53.21%. This is an aggressive reduction and reflective of a balanced capital structure that is both supportive of planned infrastructure investments and reasonable for ratepayers.

Q. How is your testimony structured with regards to the proposed equity ratio?

A. My testimony describing the key factors and providing evidence that supports the proposed equity ratio of 51.50% is organized as follows:

i. Equity Ratio / ROE Impact on Credit Quality
ii. Rating Agencies' Assessment of the Regulatory Environment
iii. Peer Authorized Equity Ratios are Higher
iv. Rating Agencies' Assessment of Equity Ratio, ROE, and Credit Metrics
v. Projected Equity Ratio Under 50% on an Adjusted Basis
vi. Summary

i. Equity Ratio / ROE Impact on Credit Quality

Q. How does the equity ratio approved in this case impact the Company's credit metrics and credit quality?

A. A key financial metric used by rating agencies is the ratio of Funds From Operations ("FFO") to Debt ("FFO-to-Debt ratio"). The calculation of this financial metric includes, in part, both the equity ratio and the authorized ROE of the Company; thus, there needs to be a balance between the Company's equity ratio and ROE that will ensure that this key financial metric does not degrade and cause significant credit deterioration. An equity ratio of 51.50% and an ROE of 10.25%, as recommended by the Company in this case, results in an FFO-to-Debt ratio that is sufficient in striking this balance.

Q. What is an FFO-to-Debt ratio?

A. An FFO-to-Debt ratio is a financial metric that compares a company's cash flow from operating activities to a company's leverage, or debt outstanding. It can also be described as a type of payback ratio, reflecting the company's ability to repay its outstanding debt with operating cash flow. A higher FFO-to-Debt ratio, one which reflects a higher level of cash flow from operating activities to offset or otherwise reduce the risk associated with the Company's ability to pay its debts, is viewed favorably and indicative of a lower financial risk and a resulting higher relative credit rating. A higher credit rating, in turn, results in lower financing rates. This is comparable to a bank's credit evaluation for someone requesting a personal loan. After reviewing personal income and outstanding debt, banks generally offer lower financing rates to individuals who have more cash flow to repay debt, indicating a relatively higher credit quality.

Q. Discuss the relationship between the Company's ROE, its equity ratio, and the Company's credit metrics.

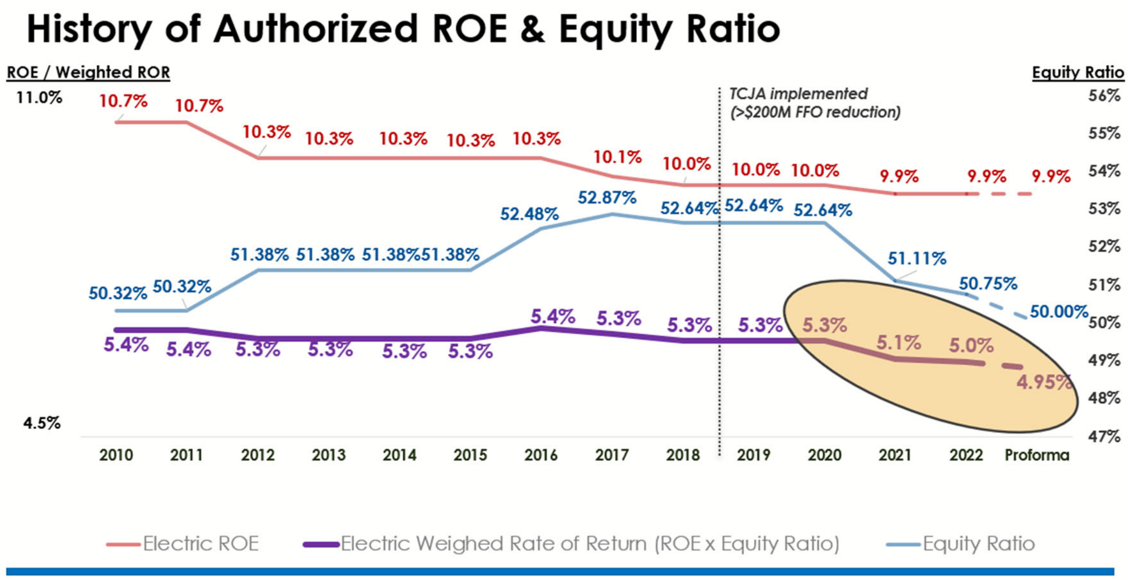
A. As discussed earlier in my testimony, ROE and equity ratio are two inputs in determining the Company's ratio of FFO-to-Debt, and FFO-to-Debt ratios are used by credit agencies to determine the Company's financial health. Consequently, it is important to recognize that the Company's ROE and equity ratio cannot be evaluated in isolation, but should, instead, be viewed as interconnected components that determine the Company's overall financial health. An ROE of 10.25%, when taken <u>together</u> with an equity ratio of 51.50% results in an FFO-to-Debt ratio that the Company believes is acceptable in the current case and is responsive to recent Commission orders. A lower authorized ROE would, therefore, necessitate a higher approved equity ratio to maintain the same level of financial health.

Q. How can the combined cost of a Company's equity ratio and ROE components be properly evaluated?

A. Multiplying the equity ratio by the ROE produces a weighted cost or "rate of return." This is shown on Exhibit A-4 (MRB-1), Schedule D-1, page 1. On line 6 of this exhibit, the equity ratio of 51.50% from column (c) is multiplied by the ROE of 10.25% from column (e) to produce a weighted cost of 5.28%, shown in column (f). This is the weighted cost of common equity, a component of the Company's overall rate of return. This rate of return is important to consider since it takes into account the equity ratio in combination with the ROE. As discussed earlier in my testimony, the 51.50% equity ratio and 10.25% ROE is a combination that the Company believes is acceptable in the current case and is responsive to recent Commission orders.

Q. What is the weighted cost of the equity ratio and ROE combination from the Order Approving Settlement in Case No. U-21308, the Company's most recent gas rate case?

A. Multiplying the equity ratio of 50.75% by the ROE of 9.90% from the Order Approving Settlement in Case No. U-21308 results in a weighted cost of 5.02%. If a 50.0% equity ratio were used with a 9.90% ROE, the resulting weighted rate of return would be even lower at 4.95%. This is illustrated in the following chart which also includes a history of electric authorized ROE, equity ratio, and resulting weighted rate of return. Note that the results from the most recent rate cases demonstrate a sharp decline in rate of return following a long period of stability.



Maintaining an authorized ROE of 9.90% without raising the approved equity ratio would result in cash flow and credit metric deterioration. It is also important to note that the 5.28% weighted cost that the Company is proposing in this case (equity ratio of 51.50% times ROE of 10.25%) is in line with orders received before recent deteriorations.

Q. What would the impact to the rating agencies' FFO-to-Debt ratios be assuming the Company realized an equity ratio of lower than 51.50% and an ROE lower than 10.25%?

A. Lowering the equity ratio and the ROE would reduce the Company's overall cost of capital and rate of return. This, in turn, lowers the Company's cash flow and FFO-to-Debt ratio. The Company would also have to increase its long-term debt to achieve a lower equity ratio. This increase in debt would also weaken the Company's FFO-to-Debt ratio. The negative impacts could cause the Company's FFO-to-Debt ratio to drop below the established rating agency thresholds, placing the Company's credit quality and credit ratings at risk.

Q. What are the customer benefits of the Company maintaining a higher credit rating?

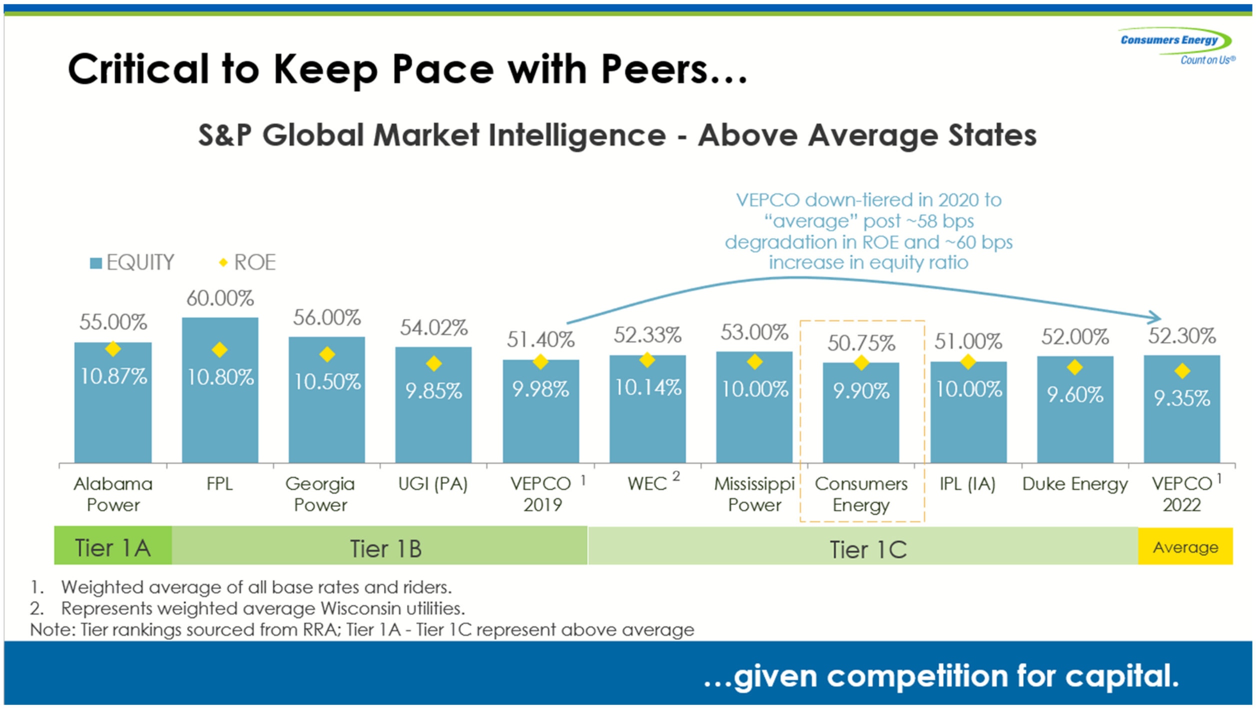
A. The Company provides a critical service that directly impacts customers' quality of life. The Company's ability to deliver long-term investments to the infrastructure that provide safe, reliable, and clean energy will depend on the financial strength of the Company, of which the Company's credit rating is a key indicator. As set forth in the testimony and exhibits of the Company's multiple capital witnesses, the Company is making significant capital investments to maintain and improve infrastructure to the benefit of customers. During this time, the Company will rely heavily on the capital markets to fund these investments. Generally, a higher credit rating results in lower financing rates. Therefore, it will be especially important for the Company to maintain strong credit ratings over this period. As shown in Exhibit A-14 (TAW-1), Schedule D-5, page 12, the Company has saved ratepayers $137 million annually as a result of improved credit ratings and lowered interest costs.

The common equity balance and equity ratio projected for the test year in this case also enable the Company to maintain strong credit ratings and better withstand any shocks in the financial markets. A current example of this was in March 2023, when Silicon Valley Bank and Signature Bank collapsed, forcing the Federal government to step in and take over the banks. Silicon Valley Bank marked the biggest failure of a United States bank since the 2008 global financial crisis and led to significant market turmoil. Other large banks such as Credit Suisse and First Republic Bank also experienced significant financial pressure caused by the ensuing market panic. In March 2023, Janet L. Yellen, the United States Treasury secretary, said "a more general problem that concerns us is the possibility that if banks are under stress, they might be reluctant to lend," and if so, that "could turn this into a source of significant downside economic risk." Strong credit ratings can help protect customers from spikes in interest rates which increase the cost of capital, and/or inaccessibility to the capital markets which serve as a key source of financing for the Company's investments on behalf of customers. Strong credit ratings can also enable the Company to issue long-term debt ahead of upcoming maturities ("pre-fund") to take advantage of low interest rates and favorable issuance windows without jeopardizing the Company's financial ratios. When market conditions are favorable, refinancing higher interest rate debt at lower rates reduces the Company's overall cost of capital included in customer rates.

ii. <u>Rating Agencies' Assessment of the Regulatory Environment</u>

Q. How else does the equity ratio and ROE impact the Company's credit quality?

A. One component of rating agencies' evaluation of credit quality involves an assessment of the Company's regulatory environment. If the Commission demonstrates a pattern of consistent, constructive rate orders, it contributes favorably to the Company's credit quality and credit rating. The authorized equity ratio and ROE are two important components in the rating agencies' assessment of the regulatory environment. As shown in the following chart as well as Exhibit A-33 (MRB-11), Standard & Poor's ("S&P") Global Market Intelligence classifies Consumers Energy as operating in an above average tier jurisdiction. As Exhibit A-33 (MRB-11) demonstrates, however, Consumers Energy is at the lower end of Tier 1 jurisdictions, and a further reduction in ROE and/or equity ratio, as suggested by intervenors in past cases, creates the risk that the Company will no longer be ranked as a utility in an above-average tier jurisdiction.



While the Company is currently considered above average, this rating is regularly evaluated. As highlighted earlier in my testimony, there has been a sharp decline in the Company's authorized weighted rate of return following several years of consistent results. A continuation or, even worse, a further degradation of the authorized equity ratio and ROE puts the Company at risk of dropping in its regulatory environment ranking which could negatively impact the Company's credit quality and credit rating. In its downgrade of the Company's credit, Moody's credit opinion states:

> Historically, CMS and Consumers Energy had produced strong and consistent metrics… However, both authorized return on equity (ROE) and regulatory equity capitalization have declined gradually over the last three years, negatively affecting these ratios. [Exhibit A-34 (MRB-12), page 1.]

The credit opinion goes on to cite the Company's Case No. U-20697 in which the Commission authorized a 9.9% ROE and a 51.11% equity ratio. Notably, prior to May 2021, Consumers Energy's credit ratings had not been downgraded by S&P or Moody's in almost two decades (July 2002).

Q. Is there evidence that analysts have started to recognize a decline in the state of the Company's regulatory environment?

A. Yes. In updating its regulatory rankings for U.S. utilities in May 2023, UBS moved Michigan down a level from Tier 1 to Tier 2. In describing the negative change, UBS specifically mentioned authorized ROE's as well as a lowering of their "subjective factor" for the Michigan regulatory jurisdiction, which is based on UBS's "knowledge of current commission actions." Refer to Exhibit A-133 (MRB-15). It is apparent that rating agencies and analysts are beginning to take note of the recent trend in the Company's regulatory outcomes. A continuation or, even worse, a further degradation of the authorized equity ratio and ROE puts the Company at risk of dropping further in its regulatory environment rankings which could negatively impact the Company's credit quality and credit rating. Michigan's above average regulatory standing needs to be protected and bolstered rather than drawn upon to push the Company toward over-leveraging.

Q. Has S&P commented on the credit quality of regulated utilities as a whole?

A. Yes. In a January 2023 report on North America regulated utilities, S&P concludes that "the industry's outlook remains negative." In its report (Exhibit A-35 (MRB-13)), S&P states that for the third consecutive year, downgrades outpaced upgrades and the industry's median rating fell to BBB+ from A-. Further, S&P states:

> More than 40% of the industry is strategically managing their financial performance with only minimal financial cushion, reflecting funds from operations (FFO) to debt that is less than 100 basis points above the downgrade threshold. Because utility cash flows are typically more stable than those of many other industries, this strategy of limiting excess credit capacity works well under ordinary conditions. However, when unexpected risks occur or base case assumptions deviate from expectations, the utility's credit

> quality can weaken, as we've seen over the past three years.
> [Exhibit A-35 (MRB-13), page 4.]

Commenting on regulated utilities' credit metrics and financial policy, S&P states "more recently, we have seen instances where not only is the authorized ROE lowered but also the equity ratio is lowered. The results have weakened the industry's financial measures, pressuring credit quality." As highlighted earlier in my testimony, there has been a sharp decline in the Company's authorized weighted rate of return following several years of consistent results as the Company has experienced the two-pronged degradation cited by S&P. It is apparent from this S&P report that a supportive ROE and equity ratio is critical in maintaining a "financial cushion" to protect against downgrade in the event of unforeseen events like the market volatility and disruption that occurred during the onset of the COVID-19 pandemic in 2020 or the financial pressure caused by the dramatic increase in gas prices and interest rates in 2022. These events and rating agency comments highlight the importance for the Company to maintain strong financial metrics and to not manage toward the perceived low end of the credit metric bands. The Company's ability to continue to provide customers with safe, reliable, and clean energy and make the necessary capital investments is directly tied to the Company's ability to maintain its financial strength. As shown in Exhibits A-34 (MRB-12), A-35 (MRB-13), A-36 (MRB-14), and A-133 (MRB-15), rating agencies have highlighted the fact that, going forward, cash flow, liquidity, and credit metrics will be critical in evaluating the Company's credit rating. Favorable credit ratings will help to ensure access to financial markets at reasonable rates. While increasing the Company's debt level may seem attractive from a cost of capital perspective, doing so limits the Company's flexibility and increases risk, neither of which is in the best interest of customers, especially during times of intense volatility and uncertainty as we are currently experiencing.

iii. <u>Peer Authorized Equity Ratios are Higher</u>

Q. Have you performed an assessment of how the 51.50% equity ratio proposed in this case compares to other utilities?

A. Yes. I researched all rate case decisions of peer companies from 2020 through September 2023 and determined the authorized or approved equity ratio for each. This is reflected on Exhibit A-32 (MRB-10). Peer companies for this analysis is defined as regulated subsidiaries of the Company's ROE proxy group in Case No. U-21308, and excludes final orders received by in-state proxy DTE Energy Company as well as the Company. The average equity ratio for the peer group was 54.03%, 253 basis points higher than the 51.50% proposed for Consumers Energy in this case. Despite this higher peer average, I am proposing a ratio of 51.50% in order to balance capital investment plans, credit metrics, customer rate impacts, the guidance of this Commission, and continues to support affordable utility infrastructure financing for the state of Michigan.

Q. Are the equity ratios reflected in your sample based on historical financial data or commission-authorized equity ratios?

A. The equity ratios were taken from commissions' orders and public filings and represent actual regulatory equity ratios authorized or approved by different commissions across the country. It is clear from this analysis that, on average, regulatory commissions of the Company's peer group are granting equity ratios that are much higher than the 51.50% that is requested by the Company in the current case.

Q. Are the utilities included in Exhibit A-32 (MRB-10) companies at the parent holding company level or the regulated subsidiary level?

A. The utilities included in Exhibit A-32 (MRB-10) are at the regulated subsidiary level. This is important because Consumers Energy is a regulated subsidiary; therefore, the comparison to the average commission-authorized equity ratios also needs to be at that same level in order for the analysis to be a valid comparable benchmark in this case.

Q. Is it appropriate to use equity ratios at the parent holding company level in order to determine the average "peer group" equity ratio for the Company in this case?

A. No. Companies at the parent holding company level should not be considered "peers" for purposes of determining the average equity ratio for the Company's peer group. This would be a misleading comparison since equity ratios at the parent holding company level may be distorted by other, non-regulated balance sheet items. In addition, an analysis of equity ratios at the parent holding company level may also be skewed since the source for this data is most likely Securities and Exchange Commission reported financial statements, which are prepared under Generally Accepted Accounting Principles ("GAAP"). There are major differences in how components of the capital structure are classified on a ratemaking basis and on a financial basis which would further distort the equity ratios calculated at the parent holding company level.

Q. Has the Commission addressed the fact that an analysis of equity ratios at the parent holding company level is not appropriate?

A. Yes. In its Order in Case No. U-20963, the Commission stated that "regulatory and financial data should not be combined" with such an analysis. Further, the Commission deemed that such an analysis is invalid assuming one "could not verify that its data contained equity ratios set by a regulatory commission in a rate case." It is clear from the Commission's Order that actual commission authorized equity ratios at the regulated subsidiary level as presented in Exhibit A-32 (MRB-10) is the preferred data source for an average equity ratio analysis.

iv. <u>Rating Agencies' Assessment of Equity Ratio, ROE, and Credit Metrics</u>

Q. Have rating agencies commented on the Company's authorized equity ratio and ROE?

A. Yes. In May 2021, when Moody's downgraded the Company's credit rating, on page 1 of this credit opinion, Moody's clearly states:

> On 3 May 2021, we downgraded the ratings of Consumers Energy due to its weakened credit metrics. Although the regulatory environment in Michigan remains relatively credit supportive, the outcome of recent rate cases has put pressure on its credit metric ratios and we do not expect the ratios to recover back to historical levels. [Exhibit A-34 (MRB-12), page 1.]

The credit opinion goes on to cite the Company's rate order from Case No. U-20697 in which the Commission authorized a 9.9% ROE and a 51.11% equity ratio. It is clear from Moody's credit opinion that the recent ROE and equity ratio authorizations and the negative impacts on the Company's credit metrics was central to their decision to downgrade the Company. The equity ratio and ROE awarded in this case, therefore, is critical to the future credit profile of the Company.

Q. Have any other rating agencies commented recently on the Company's ROE and equity ratio as it relates to the Company's credit metrics and credit quality?

A. Yes. In January 2021, S&P issued a credit opinion on Consumers Energy in which they commented on the outcome of the Company's Case No. U-20697. Exhibit A-36

(MRB-14). When referring to the equity ratio of 51.11% and ROE of 9.90% authorized in that case, S&P concluded that if these "lower ROEs and a lower equity ratio persist, credit quality could weaken." Exhibit A-36 (MRB-14), page 3. In addition, S&P noted that "we expect some modest weakening in financial metrics as a result of the recent electric rate case order…" Exhibit A-36 (MRB-14), page 4. It is clear from S&P's report that the equity ratio of 51.11% and ROE of 9.90% were not considered supportive of the Company's credit quality and continuation at these levels could negatively impact the Company's credit metrics.

Q. How does the Company's equity ratio on a regulatory (ratemaking) basis differ from rating agencies' views of the Company's equity ratio?

A. Certain credit rating agencies (e.g. Moody's) include benefits obligations as additional debt when calculating equity ratios and determining credit ratings. Other credit rating agencies (e.g. S&P) also include power purchase agreements, asset retirement obligations, and leases as additional debt when calculating equity ratios and determining credit ratings. Refer to Table 4 of Exhibit A-36 (MRB-14) which shows these adjustments for S&P. These rating agency adjustments reflect the debt-like nature of these long-term fixed payment obligations. When credit rating agencies increase debt by including these items, the ratio of equity to debt used to evaluate the Company's credit-worthiness is thereby lowered. A 51.50% equity ratio calculated by the Company, thus, gets adjusted to a lower ratio by the credit rating agencies, which, in turn, reflects a diminished credit strength held by the Company. The rating agencies' debt adjustments support the need for the Company to maintain a relatively higher unadjusted equity ratio to be on par with comparable utilities after adjustment. In addition to lowering the Company's equity ratio, rating agencies' adjustments to increase debt also reduce the Company's FFO-to-Debt ratio. As explained above, a lower FFO-to-Debt ratio negatively impacts the rating agencies' view of the Company's credit quality.

v. <u>Projected Equity Ratio Under 50% on an Adjusted Basis</u>

Q. Are there differences in how components of the capital structure are classified on a ratemaking basis and on a financial basis?

A. Yes. See Exhibit A-14 (MRB-3), Schedule D-1b, for a list of examples of the differences in component classifications. For example, capitalized leases and the effect of mark-to-market accounting would be included in determining capital structure on a financial basis. They are excluded, however, in determining a capital structure on a ratemaking basis. Also, on a ratemaking basis deferred ITC, deferred income taxes, and deferred Job Development ITC would be included.

Q. Is it appropriate for any of the capital structure components to be projected on a financial basis versus a regulatory or ratemaking basis?

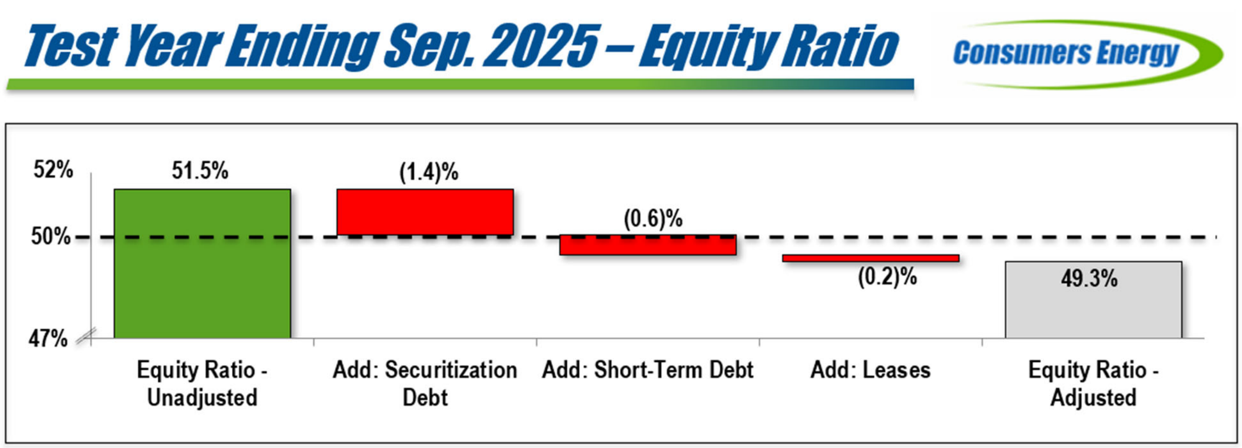
A. No. As explained earlier, there are major differences in how components of the capital structure are classified on a ratemaking basis versus a financial basis. Therefore, using a financial basis to project any of the capital structure components would lead to distorted results. The use of balances on a financial basis for any of the capital structure components is in opposition to long-standing ratemaking practices accepted by the Commission.

Q. Did the Company project any of the capital structure components using a financial basis?

A. No. Consistent with prior rate cases, all capital structure components in this case were projected on a ratemaking basis.

Q. Is the equity ratio for the test year in this case actually lower on an adjusted basis?

A. Yes. The 51.50% equity ratio reflected on Exhibit A-14 (MRB-1), Schedule D-1, page 1, excludes items such as securitization debt, short-term borrowings, and leases, because, as discussed above, these are financial-based and not regulatory-based components, and are, thus, not appropriate to include in the Company's proposed capital structure. These are, however, debt liabilities that are reflected in the Company's financial statements and are also considered as debt by rating agencies and many analysts and investors. By including these balances, which are reflected on the Company's balance sheet, the Company's debt is higher, and the resulting equity ratio is lower compared to a regulatory basis. These are debt items that are part of the Company's books and records. Exclusion of these items in the total evaluation of an appropriate capital structure for the Company does not appropriately acknowledge all of the debt recorded on the Company's balance sheet. It is important for the Company's regulators to take into consideration these debt items, which are on the Company's balance sheet, when determining the Company's authorized equity ratio so as to avoid negative credit consequences such as a credit rating downgrade. The adjusted equity ratio for the test year in this case, taking these debt balances into account, is 49.3%. This is illustrated on the following chart:



Q. Has Staff commented on the reasonableness of taking securitization debt into account when calculating a balanced capital structure for the Company?

A. Yes. In Case No. U-21090, the Company's application for approval of an Integrated Resource Plan, Staff described this approach as reasonable. In his direct testimony, Staff witness Robert F. Nichols II stated that "If the Commission were to approve securitization of the regulatory assets related to retiring coal plants, Mr. Maddipati provides a reasonable method to preserve both the Company's credit and financial profile. Mr. Maddipati proposes 'Because securitization debt is recorded on the GAAP balance sheet of the Company, the Commission could accommodate the impact of securitization by considering the incorporation of securitization debt in determining a balanced capital structure.'" See Case No. U-21090, 8 TR 3645. This same rationale also applies to short-term debt and leases which are also recorded on the Company's GAAP balance sheet.

Q. Did the Company base its proposed 51.50% equity ratio on the adjusted equity ratio calculation?

A. No. If it did, the proposed equity ratio would be higher than 51.50%.

vi. <u>Summary</u>

Q. In summary, why is having a 51.50% equity ratio, assuming a 10.25% ROE in this case, the right balance for customers and the Company?

A. In my testimony, I have shown that equity ratio and ROE have a direct impact on the Company's credit metrics and credit quality. In fact, one credit rating agency (Moody's) has already downgraded the Company's credit rating, citing both the Company's capital structure and equity ratio specifically as a factor. Further, I have shown that equity ratios for the Company's peer utilities are, on average, at 54.03%. This is much higher than the

51.50% recommended by the Company in this case. Finally, I have shown that taking into account debt-like obligations recorded in the Company's financial statements effectively reduce the projected equity ratio from 51.5% to 49.3%, a less than-balanced capital structure on an adjusted basis.

While lowering the Company's equity ratio below 51.50% may appear to have a near-term cost savings impact, as debt financing is less expensive than equity, such a move would result in a deterioration of credit quality and may lead to customers paying higher financing costs over the long-term. The equity ratio of 51.50% is appropriate and reasonable under the current circumstances, made in conjunction with the 10.25% ROE proposed by Company witness Wehner and strikes the right balance for customers, the state of Michigan, and credit rating agencies by holding the equity ratio at the Company's filed position of 51.50%.

Q. Please explain the long-term debt adjustment of $2.332 billion.

A. I have projected that the average debt balance for the test year ending September 30, 2025, will be $2.332 billion higher than the December 31, 2022 balance. This adjustment consists of the following components:

Long-Term Debt (in millions)			Sept. 30, 2025 Test Year
Month	Issuance	Retirement	Impact
Jan. 2023	$425	$0	$425
Feb. 2023	$700	$0	$700
May 2023	$400	$0	$400
Jun. 2023	$0	($300)	($300)
Aug. 2023	$500	($325)	$175
May 2024	$400	$0	$400
Aug. 2024	$620	($250)	$370
Dec. 2024	$0	($52)	($40)
May 2025	$400	$0	$154
Aug. 2025	$425	$0	$65
Subtotal			$2,349
Changes in Unamortized Fees			(17)
Total			**$2,332**

The development of the 13-month average long-term debt balance is shown on Exhibit A-14 (MRB-2), Schedule D-1a, page 2.

Q. Please describe the planned debt issuances in May 2024, August 2024, May 2025, and August 2025.

A. The debt planned to be issued in May 2024, August 2024, May 2025, and August 2025 will be used for general corporate purposes of the Company including financing capital expenditures. The debt planned to be issued in May 2024 will also be used for the retirement of the Company's $250 million 3.125% bonds which mature in August 2024. The debt planned to be issued in August 2024 will also be used for the retirement of the Company's $52 million 3.19% bonds which mature in December 2024. These planned debt issuances have been determined based on the Company's financing plans after evaluating cash and liquidity requirements for the Company.

Q. What long-term debt was included in developing the 13-month average amount outstanding for the period ending September 30, 2025?

A. Exhibit A-14 (MRB-4), Schedule D-2, shows the long-term debt that was included in developing the 13-month average for the period ending September 30, 2025. The average amount outstanding on line 63, column (j), ties to the 13-month average balance shown on Exhibit A-14 (MRB-2), Schedule D-1a, page 2.

Q. What is your projection regarding the level of short-term debt balance for the test year ending September 30, 2025?

A. I have projected an average short-term debt balance for the test year of $287 million. This balance is shown on Exhibit A-14 (MRB-1), Schedule D-1, page 1, line 10, column (b), and on Exhibit A-14 (MRB-2), Schedule D-1a, page 1, line 10, column (g).

Q. What are the components of the average short-term debt balance?

A. The average short-term debt balance is composed of two components. The first is the average short-term debt – short-term liquidity facilities balance of $225 million. The second is the average short-term debt – renewable liability balance of $62 million. These balances are shown on Exhibit A-14 (MRB-5), Schedule D-3, page 1, lines 1 and 3.

Q. What are the components of short-term liquidity facilities?

A. Revolvers, commercial paper, and intercompany borrowing are short-term financing options available to the Company. Revolvers are revolving lines of credit that allow the Company to borrow and repay as long as the outstanding balances remain within the credit limits, or capacity. Commercial paper represents debt issuances under the Company's Commercial Paper Program that are short-term in nature, typically 1- to 90-day maturities. Intercompany borrowing represents short-term borrowings from CMS Energy. Intercompany borrowing is drawn under a promissory note with CMS Energy up to $500 million and carries an interest rate of 1-month Secured Overnight Financing Rate ("SOFR")[1] minus 10 basis points. The Company is the beneficiary of intercompany borrowing to meet short-term liquidity needs when it is available and when it is the most cost-effective alternative. It should be noted that the intercompany borrowing facility is not a dedicated financing option that is always available for the Company to use, but only when CMS Energy has surplus cash and effective borrowing rates must be lower than rates available to the Company under the Commercial Paper Program. The intercompany borrowing facility, therefore, is not considered part of the total liquidity capacity available to the Company.

Q. How was the short-term liquidity facilities balance of $225 million developed?

A. Exhibit A-14 (MRB-7), Schedule D-6, shows the projected balances, by month, of short-term liquidity facilities for the test year ending September 30, 2025. I have arrived at these projections after considering the projected total monthly cash flow requirements,

---

[1] SOFR, a benchmark interest rate used in calculating short-term variable interest rates throughout the world. SOFR replaced the London Interbank Offered Rate (LIBOR) in 2023.

planned long-term debt (net) and equity issuances, and the amount of short-term financing available.

Q. How do these projections compare with the historical 2022 period?

A. The short-term liquidity facilities balances were significantly higher in the historical 2022 period as a result of the need for the Company to fund purchases of natural gas, which saw a dramatic increase in price in 2022. The Company was able to secure $1 billion of short-term financing capacity in July 2022 to meet the excessive short-term borrowing requirements of the higher gas prices. The Company utilized the full capacity of this facility in December 2022 and extinguished the entire amount in February 2023 following the issuance of long-term debt.

Q. Are the projections for short-term debt – short-term liquidity facilities reflected on Exhibit A-14 (MRB-7), Schedule D-6, expected to be issued under the Company's revolvers, its Commercial Paper Program, or its intercompany borrowing agreement?

A. The Company borrows on its short-term financing facilities in order from least expensive to more expensive. The following is the prioritized order in which the Company utilizes its short-term financing facilities:

		Amount	Credit Capacity
1a.	Commercial Paper	$500 million	$500 million*
1b.	Intercompany Borrowing**	$500 million	
2.	Scotiabank Revolver	$250 million	$250 million
3.	JPMorgan Revolver	$1.1 billion	$600 million*
	Total		$1.35 billion

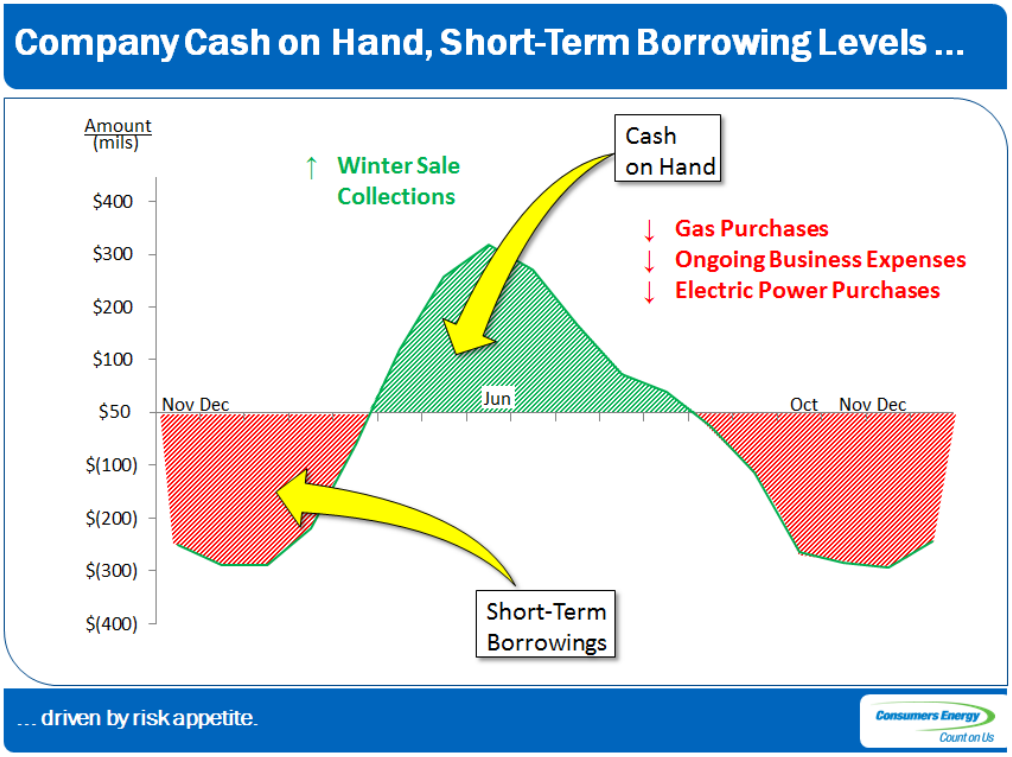
*Takes away $500 million of the JPMorgan revolver's $1.1 billion capacity (leaving $600 million available).

**Intercompany Borrowing or Commercial Paper is used first, depending on availability and which alternative is the most cost-effective at the time of borrowing.

All of the projected test year balances for short-term debt – short-term liquidity facilities are assumed to be issued under the Company's Commercial Paper Program. This program, along with the intercompany borrowing facility, are the least expensive short-term financing options to the Company and are assumed to be used first when the need arises. The Company's $250 million Scotiabank revolving credit facility is the next least-costly, short-term financing option, with the remaining $600 million revolver ($1.1 billion total capacity less $500 million drawn commercial paper) assumed to be used last.

Q. How does the timing and amount of short-term borrowings fit into the Company's overall liquidity and financing strategy?

A. The Company strives to match long-term investments with long-term financing and to finance short-term liquidity needs with its cash and short-term borrowing facilities. The timing and amount of short-term borrowings is directly related to the level of cash on hand. Due to the seasonal nature of utility cash inflows and outflows, the Company generally holds more cash in the spring and summer months and relies on short-term borrowing in the fall and winter months. Throughout the year, however, a minimum level of cash on hand is maintained. This is reflected in the following chart which depicts the typical cash and short-term borrowing levels through a given year:



Q. In order to reduce costs, would the Company consider maintaining a permanent layer of short-term debt?

A. No. Short-term financing markets can be volatile and, at times, access to those markets completely disappear, as was witnessed during the 2008 credit crisis, again in March 2020 as a result of pandemic-related market fear, and again in March 2023 during the banking industry turmoil described earlier in my testimony. Based on the experience and judgment of the Company's Treasury Department, as well as members of the Financial Planning and Analysis Department, the Company does not pursue a strategy that maintains a permanent balance of short-term debt. However, the Company does fund seasonal fluctuations in its working capital with short-term debt as previously illustrated. Based on historical trends of these seasonal fluctuations, the difference between the maximum working capital surplus and the maximum level of working capital deficiency (peak-to-valley) is approximately $300 million to $600 million. The Company is generally comfortable financing between $200 million and $400 million of this gap with short-term borrowings as doing so leaves adequate undrawn capacity in the event of financial market volatility or disruption. In addition, rating agencies assess the Company's liquidity as a component of their overall credit rating methodology. Reducing cash balances and relying consistently on short-term borrowings would weaken the Company's liquidity metrics. Finally, if the Company were to establish and maintain a permanent level of short-term debt, this should be taken into account in calculating the appropriate equity ratio in this case. If the short-term debt balance were included in the debt-to-equity ratio calculation, the required equity balance would need to increase in order to achieve the appropriate 51.50% equity ratio. Doing so would result in a higher overall cost of capital. It should be noted that the Commission explicitly agreed with the Company's cash and short-term debt balances in Case No. U-20697.

Q. How does the Company balance the benefit of carrying sufficient liquidity with the cost of maintaining its short-term credit capacity?

A. The Company's projected $1.35 billion total short-term credit capacity is reasonable and necessary to conduct daily operations and also to keep credit risk at a reasonable level. To maintain strong financial health, it is important for the Company to maintain adequate short-term financing capacity for normal business operations while retaining an adequate amount of additional liquidity for cases of extreme market fluctuations or other unforeseen circumstances. As shown in Exhibit A-14 (MRB-7), Schedule D-6, the Company projects $485 million of short-term borrowings in November 2024, utilizing most of the $500 million capacity of the Commercial Paper Program. Access to the commercial paper market, however, requires an equivalent amount of revolving credit capacity as a "backstop"; therefore, of the Company's $1.35 billion of revolving credit facilities, $500 million is used to support commercial paper issuance. The remaining $850 million of revolver capacity is a vital backstop for capital expenditures and upcoming long-term debt maturities.

Q. Did the dramatic increase in natural gas prices in 2022 serve as an example of the importance of the Company holding sufficient short-term credit capacity?

A. Yes. The Company generally funds its natural gas purchases using short-term borrowing. Surging demand in the United States combined with national inventory levels below historical averages drove gas prices higher in 2022. In addition, Russia's invasion of Ukraine and the related energy market disruptions further increased gas prices. As a result, the Company had to purchase natural gas at significantly higher prices. In fact, the Company held over $1 billion in short-term debt in November and December 2022, as previously described. These elevated short-term borrowing levels can be seen on Exhibit A-14 (MRB-7), Schedule D-6. While the Company was able to secure a $1 billion term loan in July 2022 to meet the excessive short-term borrowing requirements, access to this type of facility at reasonable interest rates is not guaranteed in the future, particularly during times of extreme capital market volatility or the inability to access those markets as described earlier in my direct testimony. The dramatic increase in gas prices in 2022 and the resulting elevated short-term borrowing levels highlights the importance of maintaining sufficient short-term credit capacity to ensure that the Company is able to adequately fund gas purchases, continue operations, and serve customers.

Q. What does the short-term debt–renewable liability represent?

A. This liability represents the amount of renewable surcharges that the Company has collected in excess of the required revenue requirements for the renewables portfolio standard.

Q. How was the renewable surcharge liability balance developed?

A. I have projected an average renewable surcharge liability of $61.5 million for this case. Exhibit A-14 (MRB-7), Schedule D-6, shows the monthly projections of this liability. The projections are consistent with Consumers Energy's RE Plan in Case No. U-21197.

Q. Please explain the deferred income tax adjustment of $645 million.

A. The Company's Tax Department has projected that the average deferred income tax balance for the test year ending September 30, 2025, will be $645 million higher than the December 31, 2022 balance. This increase is based on projecting book versus tax differences that the Company expects to record from January 2023 through September 2025. These adjustments total $645 million on a 13-month average basis for the test year. The development of the 13-month average deferred income tax balance is shown on Exhibit A-14 (MRB-2), Schedule D-1a, page 4.

Q. How was the ITC balance determined?

A. The Company's Tax Department has projected that the average ITC balance for the test year ending September 30, 2025 will be $118 million - $6 million higher than the December 2022 balance. The balance is based on forecasted balances of both existing and anticipated new ITC credits that the Company expects to record from January 2023 through September 2025. These adjustments total $6 million on a 13-month average basis for the test year.

Q. What balances did you use for ITC in the proposed capital structure?

A. I allocated the components for ITC based upon the allocation of long-term debt, preferred stock, and common equity in the recommended capital structure.

B. <u>Development of Cost Rates</u>

Q. Please explain the development of the total weighted cost of capital shown on Exhibit A-14 (MRB-1), Schedule D-1, page 1, line 19, column (g).

A. Column (d) represents the percentage of total capital provided by each of the components of the capital structure shown in column (a). These percentages were developed by dividing the amounts of capital shown in column (b) by the total ratemaking capitalization amount shown in line 19, column (b). Column (e) presents the costs, on a ratemaking basis, of each of the components in total ratemaking capitalization. Column (g) is the after-tax weighted cost of capital and is calculated by multiplying column (d) by column (e). The pre-tax weighted cost is shown in column (i) and is calculated by multiplying column (g) by the conversion factors in column (h).

i. <u>Long-Term Debt Cost Rate</u>

Q. What long-term debt annual cost rate did you use in this case?

A. I developed a 4.31% annual cost for long-term debt. The development of this annual cost rate is shown on Exhibit A-14 (MRB-4), Schedule D-2. Consistent with past Commission practice, the costs are determined on a net proceeds basis. I began with the debt issuances outstanding as of December 31, 2022. I then added the new debt issuances in January 2023, February 2023, May 2023, and August 2023. I then added the planned new debt issuances in May 2024, August 2024, May 2025, and August 2025. These new debt issuances are shown on Exhibit A-14 (MRB-4), Schedule D-2, lines 36 through 46.

Q. Why did you use cost on a net proceeds basis?

A. Not reflecting costs on a net proceeds basis would understate costs. The net proceeds methodology accounts for underwriters' compensation and finance expenses. The fees and expenses are shown as a reduction in proceeds from the issuance of new securities, thereby increasing the cost of the issuance over the stated coupon rate.

Q. Please explain the cost rate you assumed for the planned debt issuances in May 2024, August 2024, May 2025, and August 2025.

A. I assumed that all of the planned debt issuances will be 30-year bonds with a fixed coupon (interest) rate. To calculate the total interest rate (coupon) projection for these bonds, I started with the projected 30-year U.S. Treasury rate which was provided by Company witness Wehner. For each of these planned debt issuances, I then added a 138 basis point credit spread. These interest rate calculations are shown on Exhibit A-14 (MRB-4), Schedule D-2.

Q. What is a credit spread?

A. A credit spread reflects the compensation investors receive for bearing credit risk of the investment in addition to the underlying Treasury rate. The total interest rate on a corporate bond is the summation of both the Treasury rate and the credit spread.

Q. How did you calculate the credit spread of 138 basis points?

A. Unlike U.S. Treasury rates, credit spreads for long-term bond issuances are not projected by financial forecasting companies. This is because spreads are very difficult to predict. Interest rate spreads are based on a number of factors, most notably the Company's credit rating and the market conditions at the time of the debt issuance, including both same-day and short-term supply/demand dynamics. Given the lack of a reliable source for projected credit spreads, I applied the calculated average from the last 15 years. From 2009 to September 2023, the average credit spread on a 30-year debt issuance for investment grade utilities was approximately 138 basis points.

Q. Are there any existing long-term debt issuances that have variable interest rates?

A. Yes. There are three debt issuances shown on Exhibit A-14 (MRB-4), Schedule D-2, which have variable interest rates. The Floating Rate First Mortgage Bonds ("FMB") issuances shown on line 28 and lines 31 through 32 have variable interest rates.

Q. What cost rates did you use for these variable rate issuances?

A. The interest rate for the Floating Rate FMB issuances is equal to SOFR less 30 basis points. Therefore, I took the projected three-month SOFR for the test year in this case provided by Company witness Wehner (equal to 4.35%) and subtracted 30 basis points for an interest rate of 4.05%.

Q. Are the projected interest rates for the Company's projected long-term debt issuances as well as the cost rates for the Company's variable rate debt issuances relatively higher than in previous rate case filings?

A. Yes. In order to combat rising inflation, the Federal Reserve has raised its federal funds benchmark rate. This has had a direct impact on U.S. Treasury rates (the basis of long-term debt issuance rates as described above) as well as SOFR (the basis for the cost rates on the Company's variable rate debt issuances as described above). In fact, the Federal Reserve has made the following rate hikes in 2022 and so far in 2023:

- March 2022 – Raised 25 basis points, the first time that the Federal Reserve has increased rates since 2018;
- May 2022 – Raised 50 basis points;
- June 2022 – Raised 75 basis points;

- July 2022 – Raised 75 Basis points;
- September 2022 – Raised 75 basis points;
- November 2022 – Raised 75 basis points;
- December 2022 – Raised 50 basis points;
- February 2023 – Raised 25 basis points;
- March 2023 – Raised 25 basis points;
- May 2023 – Raised 25 basis points; and
- July 2023 – Raised 25 basis points.

These rate increases result in higher projected interest rates on the Company's future long-term debt issuances as well as the Company's existing variable rate debt.

Q. Does the rising interest rate environment support the 10.25% ROE assumed by the Company in this rate case?

A. Yes. The Company's projected ROE can be calculated as a risk free (U.S. Treasury) rate plus an additional compensation for risk. The risk free (U.S. Treasury) rate is increasing at a dramatic pace as a result of the Federal Reserve's actions as described above. In addition, the rising interest rate environment, when taken together with rising inflation, and the geopolitical issues discussed earlier in my direct testimony, increases risk for the Company that the projected long-term debt rates will be insufficient and therefore making it more challenging for the Company to earn its ROE. Investors, in turn, must be compensated for this increased risk in the form of a higher ROE. For these reasons, the 10.25% ROE recommended by Company witness Wehner should be accepted by the Commission.

Q. Please explain Exhibit A-14 (MRB-4), Schedule D-2, line 57.

A. Exhibit A-14 (MRB-4), Schedule D-2, line 57, represents the amortization of losses on reacquired Consumers Energy debt (including call premium) for refinancings. This amortization needs to be added to the interest cost on the refinanced debt to determine Consumers Energy's true financing cost for the long-term debt. The Commission recognized recoverability of these costs in establishing the cost rate in Case No. U-16794.

Q. How did you calculate the amount shown on Exhibit A-14 (MRB-4), Schedule D-2, line 57?

A. The amount shown on line 57 represents the amortization of losses on reacquired debt with refunding (including call premiums). The projected amortization expense for the 12-month period ending September 2025 is $4,305,000.

ii. <u>Short-Term Debt Cost Rate</u>

Q. What short-term debt cost rate did you use in this case?

A. I used a short-term debt cost rate of 5.16%. This cost rate is shown on Exhibit A-14 (MRB-5), Schedule D-3, page 1, line 5.

Q. Please explain the cost of short-term debt.

A. As explained earlier, the short-term debt balance is composed of two components. The first is short-term debt – short-term liquidity facilities. I calculated the annual cost of short-term debt – short-term liquidity facilities to be $12.1 million. The second component is short-term debt – renewable liability. I calculated the annual cost of this component to be $2.7 million. This is shown on Exhibit A-14 (MRB-5), Schedule D-3, page 1, lines 1 and 3, column (b). The total average balance of short-term debt, shown on Exhibit A-14 (MRB-5), Schedule D-3, page 1, line 5, column (a), is $286.6 million. Dividing the total cost of $14.8 million by the total average short-term debt balance results in a total short-term debt cost rate of 5.16%, as shown in column (c).

Q. Please explain the cost of short-term debt – short-term liquidity facilities.

A. As indicated above, I projected a cost of short-term debt – short-term liquidity facilities of $12.1 million. The development of this cost is shown on Exhibit A-14 (MRB-5), Schedule D-3, page 2. The cost of short-term debt – revolver has four components:

1. **Interest on Borrowings** – Equal to the projected outstanding balance times the projected interest rate. The projected balance, all assumed to be commercial paper, is $225.1 million, calculated on Exhibit A-14 (MRB-7), Schedule D-6. Commercial paper issuances are short term in nature, typically 1- to 90-day maturities. Interest charged on these short-term borrowings are based on several different factors, including market conditions, investor demand, and the tenor (number of days borrowed) of the issuance. I approximated the interest on commercial paper borrowings using the projected SOFR rate for the test year of 4.35%. This was multiplied by the projected balance of $225.1 million. Exhibit A-14 (MRB-5), Schedule D-3, page 2, shows the projected cost of $9.8 million for borrowings under the Commercial Paper Program;

2. **Letter of Credit Fees** – Equal to the projected Letters of Credit outstanding times a rate set forth by the facility the Letters of Credit are issued under. Exhibit A-14 (MRB-5), Schedule D-3, page 2, shows the projected cost of $0.7 million for Letter of Credit Fees. The Letter of Credit Fees shown on Exhibit A-14 (MRB-5), Schedule D-3, page 2, pertain to normal business Letters of Credit to cover ongoing items such as fuel purchases or margin support and also Letters of Credit to cover Midcontinent Independent System Operator, Inc. margin obligations;

3. **Unused (Commitment) Fees** – This cost consists of Annual Revolver Commitment Fees, which the Company is required to pay quarterly to the banks on the "unused" portion of the JPMorgan revolver and the Scotiabank revolver, and other required annual fees under the Revolving Credit agreements. The Revolver Commitment Fees are associated with maintaining fund availability. It should be noted that borrowings under the Company's Commercial Paper Program reduce the "availability" (or the amount the Company is able to draw) of the JPMorgan revolver but do not reduce the "unused" portion of the revolver in calculating the unused (commitment) fees. Exhibit A-14 (MRB-5), Schedule D-3, page 2, shows the projected cost of $0.9 million for commitment fees; and

4. **Amortization/Expense of Facility Fees** – At the inception of a revolving credit facility, the borrower is required to pay upfront fees and issuance costs to the

lenders. These issuance and upfront costs are amortized over the life of the revolver. For the Commercial Paper Program, there are annual fees required to maintain the facility. Exhibit A-14 (MRB-5), Schedule D-3, page 2, shows the projected cost of $0.7 million for amortization of upfront revolver fees.

Q. Why is it important to allow for the recovery of commitment fees and amortization of facility fees in addition to the interest on short-term borrowings and interest on letters of credit?

A. These fees and costs are customary in revolving credit facilities and commercial paper agreements and are necessary to secure the financing and to keep the facilities available for the financing needs of the Company. The Company cannot avoid incurring these costs except by giving up the short-term borrowing facilities, which would not be a sound business decision. If these fees are not recovered through short-term debt cost, then they need to be recovered as part of long-term debt cost. The cost of short-term debt – short-term credit facilities represents the cost to provide $1.35 billion of necessary liquidity to Consumers Energy.

Q. What cost have you used for the short-term debt – renewable liability?

A. Section 21(4) of Public Act 295 of 2008 discusses the cost rate for the renewable liability, and it provides for "the creation of a regulatory liability that accrues interest at the average short-term borrowing rate available to the electric provider during the appropriate period." I have used the projected short-term borrowing rate available to the Company under its Commercial Paper Program of 4.35%. I then applied this rate to the projected average renewable liability balance for the test period of $61.5 million, shown on Exhibit A-14 (MRB-7), Schedule D-6. This results in a total cost for the test year of $2.7 million.

Q. Are the projected interest rates for the Company's short-term borrowings relatively higher than in previous rate case filings?

A. Yes. The higher short-term borrowing cost is a result of the dramatic rise in interest rates as described earlier in my direct testimony.

iii. Preferred Stock Cost Rate

Q. What is the annual cost of preferred stock?

A. The annual cost of preferred stock is shown on Exhibit A-14 (MRB-6), Schedule D-4. This cost is 4.50%.

iv. Common Equity Cost Rate

Q. What rate did you use for the cost of common equity?

A. Based on my recommended equity ratio of 51.50%, I applied Company witness Wehner's cost rate of 10.25% for common equity. As explained earlier in my testimony, to the extent that the Commission authorizes a lower equity ratio than that proposed by the Company, a higher ROE is necessary to prevent the potential for adverse credit impacts. The Company generally believes it is preferable for the ratemaking equity ratio to reflect the Company's actual capital structure (i.e. ratemaking should match reality). The Company's capital structure and ROE recommendations in this case reflect the appropriate levels that the Commission should adopt with that principle in mind in order to preserve Consumers Energy's current credit rating.

v. Other Cost Rates

Q. What cost rates did you use for the remaining components of the capital structure?

A. Consistent with MPSC ratemaking practice, deferred income taxes are included at zero cost. The cost rates for each of the three components of ITC correspond to the cost rates for long-term debt, preferred stock, and common equity.

III. EXHIBITS FOR CERTAIN FILING REQUIREMENTS – CREDIT RATINGS, AND RECENT UTILITY BOND ISSUANCES

Q. Please describe Exhibit A-30 (MRB-8).

A. Exhibit A-30 (MRB-8) is included per the rate case filing requirements. In its December 23, 2008 Order in Case No. U-15895, the Commission directed that utilities include an exhibit that provides current and historical credit ratings with associated outlooks for the previous five years for the utility and its parent company. Exhibit A-30 (MRB-8) shows Consumers Energy's and CMS Energy's current and historical credit ratings, along with associated credit outlooks, for the previous five years as published by S&P, Moody's, and Fitch Ratings. The credit ratings include senior secured debt, commercial paper, senior unsecured debt, preferred stock, junior subordinated debt, hybrid preferred securities ratings, and preferred stock ratings.

Q. Please describe Exhibit A-31 (MRB-9).

A. In its December 23, 2008 Order in Case No. U-15895, the Commission directed that utilities include an exhibit that provides certain information related to bond issuances. Exhibit A-31 (MRB-9) shows recent public utility corporate bond issuances for a period of three months prior to and three months subsequent to, each of Consumers Energy's long-term public debt offerings issued during the 24 months prior to the date of the Application in this rate case. This summary includes the issue date, issuing company, type of offering (either secured or unsecured), amount of offering, coupon rate, S&P and Moody's credit ratings, maturity date, and spread on U.S. Treasury.

IV. PROJECTED CASH BALANCE

Q. Do you believe that the projected cash balance for the test year ending September 30, 2025, should be based on the 13 months ended June 30, 2022 (the working capital historical period)?

A. No. As described earlier in my testimony, there was a significant increase in natural gas prices in 2022. During this time, the Company was forced to use cash on hand as well as short-term borrowings to fund these higher gas price purchases. As a result, using the 13 months ended June 2022 results in a cash balance of $9 million, which is lower than what is normally expected and required for the Company in the test year of this case.

Q. What period do you believe that the projected cash balance for the test year ending September 30, 2025 should be based on?

A. I believe that the projected cash balance for the test year in this case should be based on the 13 months ended March 31, 2022 which results in a cash balance of $22 million. The cash levels from this period pre-date the spike in gas prices and thus are appropriate since it is reflective of normal levels of cash balance.

V. SUMMARY AND CONCLUSIONS

Q. Please summarize your recommendations and conclusions.

A. Consumers Energy's capital structure should be based on the capital structure as of December 31, 2022, adjusted for the known and expected changes in long-term debt, common equity, short-term debt, deferred income taxes, and ITC, as shown on Exhibit A-14 (MRB-1), Schedule D-1. The cost rates developed are fair and reasonable and commensurate with the risks for the period of time rates are expected to be in effect. As shown on Exhibit A-14 (MRB-1), Schedule D-1, I recommend an overall after-tax rate of return of 6.20%. Also, the Company's projected cash balance for the test year in this case should be based on the 13 months ending March 31, 2022, which results in a balance of $22 million.

Q. Does this conclude your direct testimony?

A. Yes.

S T A T E O F M I C H I G A N

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the application of	)	
CONSUMERS ENERGY COMPANY	)	
for authority to increase its rates for the	)	Case No. U-21490
distribution of natural gas and for other relief.	)	
	)	

DIRECT TESTIMONY

OF

ADAM S. CARVETH

ON BEHALF OF

CONSUMERS ENERGY COMPANY

December 2023

Q. Please state your name and business address.

A. My name is Adam S. Carveth, and my business address is 14500 Dixie Hwy, Holly, Michigan 48442.

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

A. I am employed by Consumers Energy Company ("Consumers Energy" or the "Company") as East Sr. Manager of Shared Services Field Operations.

Q. What is your formal educational experience?

A. I hold an Associate in Applied Science in Automotive Service Technology and a Bachelor of Science in Automotive and Heavy Equipment Management from Ferris State University, located in Big Rapids, Michigan.

Q. What are your responsibilities as East Sr. Manager of Shared Service Field Operations?

A. I provide daily operational oversight within our material storerooms and both our Fleet and Facilities repair and maintenance services.

Q. Would you please describe your previous work experience?

A. In 2006, I started my career at EK Automotive in Chicago, Illinois, as a Service Advisor. EK Automotive is an automotive repair shop servicing all light duty makes and models. In 2009, I took a position as Work Equipment Analyst for Canadian National Railroad. During my time in that role, I was involved with capital purchase, budget oversight, specification verification, and data integrity. In late 2009, I began a series of changing roles, with increasing responsibility, at Canadian National Railroad that continued through 2014. These roles were as follows: Assistant Track Supervisor, Engineering Track Services, Production Supervisor, and Track Supervisor. In 2015, I accepted the position of

Fleet Field Leader with Consumers Energy in the Eastern Zone. The Fleet Field Leader position consisted of oversight of all preventive maintenance and repairs to Consumers Energy's Fleet within the zone. In 2018, I was promoted to Senior Fleet Field Leader for the Southeast Zone. Within the position, I provided oversight to 5 Field leaders, 2 schedulers, and 29 mechanics. The position also provided oversight to the Company's Enhanced Infrastructure Replacement Program Department that contracts all preventative maintenance and repairs. In early 2021, I was promoted to Director of Fleet Strategy. Within this position, I provided oversight of Fleet Acquisition & Dispositions, supporting the current and long-term capital replacement strategy, vehicle deposition, licensing, and internal Electric Vehicle Strategy. In addition, I provided oversight to our Fleet Regulatory & Technical function, which supports safety and regulatory compliance across the Company related to Fleet assets and technicians. In September of 2023, I accepted the position of East Sr. Manager of Shared Services Field Operations.

Q. Have you previously been a witness, or supported witnesses, in any proceedings before the Michigan Public Service Commission ("MPSC" or the "Commission")?

A. Yes. I provided testimony on behalf of the Company in the three most recent electric rate cases, Case Nos. U-20963, U-21224, and U-21389 regarding the Company's proposed recovery of its electric business portion of Fleet services. I was also the expert witness on behalf of the Company in the two most recent natural gas rate cases, Case Nos. U-21148 and U-21308, regarding the Company's proposed recovery of its gas business portion of Fleet services.

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

A. The purpose of my direct testimony is to support the Company's costs related to the Gas business portion of Fleet services. To that end, I will:

I. Describe the Company's Fleet and how it is managed through Fleet Services;

II. Explain the Company's Fleet Replacement Planning Process;

III. Explain the Company's Fleet Electrification Strategy; and

IV. Sponsor the Company's Fleet capital spending projections.

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

A. Yes. I am sponsoring the following exhibits:

Exhibit A-12 (ASC-1)	Schedule B-5.3	Summary of Actual & Projected Capital Expenditures;
Exhibit A-37 (ASC-2)		Fleet Responsibility Costs;
Exhibit A-38 (ASC-3)		Detailed List of Projected Gas Capital Expenditures Fleet Services for the Years 2022, 2023, 2024 and test year 12 months ending September 28, 2025; and
Exhibit A-39 (ASC-4)		Summary of Fleet Tooling Actual & Projected Capital Expenditures.

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

A. Yes.

Q. Please briefly describe the exhibits that you are sponsoring.

A. I am sponsoring Exhibit A-12 (ASC-1), Schedule B-B-5.3, which is a Summary of Actual and Projected Fleet Capital Expenditures for the calendar year 2022, bridge period (21 months ending September 30, 2024), and the projected test year 12 months ending September 30, 2025; Exhibit A-37 (ASC-2), which provides details of the Company's Fleet responsibility dollars; Exhibit A-38 (ASC-3), which provides details of the Company's

Fleet acquisitions in the historical year 2022, bridge period (21 months ending September 30, 2024), and the projected test year 12 months ending September 30, 2025; and Exhibit A-39 (ASC-4) which is a Summary of Actual and Projected Fleet Tool Capital Expenditures for the historical year 2022, bridge period (21 months ending September 30, 2024), and the projected test year 12 months ending September 30, 2025.

I. FLEET SERVICES FUNCTION AND RESPONSIBILITIES

Q. Please explain the responsibilities of Fleet Maintenance Operations.

A. Fleet Maintenance Operations is responsible for maintaining a safe, cost effective, and reliable fleet. This is accomplished through preventative maintenance, regulatory inspections, parts inventory management, and maintenance scheduling across 36 garage locations with approximately 110 mechanics. Maintenance Operations also oversees mechanic contractor crews for preventative maintenance and repairs performed in the field.

Q. Please explain the responsibilities of Fleet Acquisitions.

A. Fleet Strategy executes all functions related to the acquisition and disposition of Company owned and rented vehicles and related equipment. This includes management of the Fleet capital purchase plan, vehicle specification design, license/title, and registration, as well as asset retirement.

Q. Please explain the Company's overall fleet structure.

A. As stated above, the Company's fleet includes approximately 7,340 owned, leased, and rented units across 36 locations. These units include light duty vehicles (approximately 2,600 units), medium and heavy-duty trucks (approximately 1,400 units), various types of equipment (approximately 1,400 units), and trailers (approximately 1,900 units). Internally, the Company categorizes its fleet into several specifications ("spec(s)"), each of which is a given type, model, and description of a vehicle. Each spec has a defined intended use, acquisition cost, operating cost, and expected life in years and mileage.

Q. How is the Company's fleet divided between the electric and natural gas businesses?

A. The Company divides its fleet between the electric and natural gas businesses by determining which business unit at a given location is using each particular vehicle. The needs of the business require the deployment of dedicated teams to safely complete work utilizing specific tools and processes – this extends to the vehicle supporting said work. These vehicles are ordered and upfitted to support specific work and are, therefore, specialized for the work they perform; however, the Company does seek ways units can be shared across the business when possible. The fleet requirements for the location will vary based on the service provided to the customer (electric, gas, or both), crew counts, and region. Additionally, some Company fleet units serve both electric and gas functions and are referred to as "common" units, which are utilized by support organizations, such as Facilities, Fleet, and Supply Chain. Overall, the Company's fleet is 40% electric, 50% gas, and 10% common by number of vehicles.

Q. What is the purpose of Fleet Services as it relates to the Company's Gas business?

A. Specific to the Company's gas business, Fleet Services' purpose is to provide vehicles and equipment that enable Gas Operations to serve customers with safe, reliable, and affordable Gas service. This is accomplished by ensuring that the Company's Fleet assets are available to execute the work plan and respond to emergencies in the most efficient, cost-effective, and safe manner when required.

Q. Does the Company's fleet incur both capital and operating and maintenance ("O&M") costs?

A. The Company makes direct capital investments in its fleet as provided in Exhibit A-12 (ASC-1), Schedule B-5.3 and Exhibit A-37 (ASC-2). The Company also incurs other costs related to its fleet that are treated as "fleet responsibility" dollars, which in this case are presented in Exhibit A-37 (ASC-2).

Q. What are fleet responsibility dollars?

A. In addition to direct capital expenditures for fleet vehicles, tools, and other equipment, the Company also incurs other costs related to its fleet that are treated as "fleet responsibility" dollars. The Company does not have specific Fleet O&M expenses. Fleet operating costs are reported in responsibility dollars. Each fleet unit has defined work assignments that determines which functional areas are allocated the associated responsibility dollars for the unit. Fleet responsibility costs are allocated to both capital and O&M expenses based on the work assignment performed.

Q. Please explain how fleet responsibility dollars are allocated to both capital and O&M.

A. The process for allocating fleet responsibility dollars is a multi-step process. The first step in the process is that costs associated with each fleet vehicle or piece of equipment are charged to an internal order. Each fleet vehicle/equipment has its own internal order that collects costs like fuel and maintenance, which is assigned to a department/responsibility area.

The next step is that the costs from the internal orders are moved to separate fleet clearing accounts for each department/responsibility area. The final step in the process is the allocation of the costs from the fleet clearing accounts. The costs in each clearing account are allocated to work orders or cost centers based on the labor charges for that department/responsibility area. Additionally, the fleet costs to be allocated are separated between labor and non-labor fleet loading.

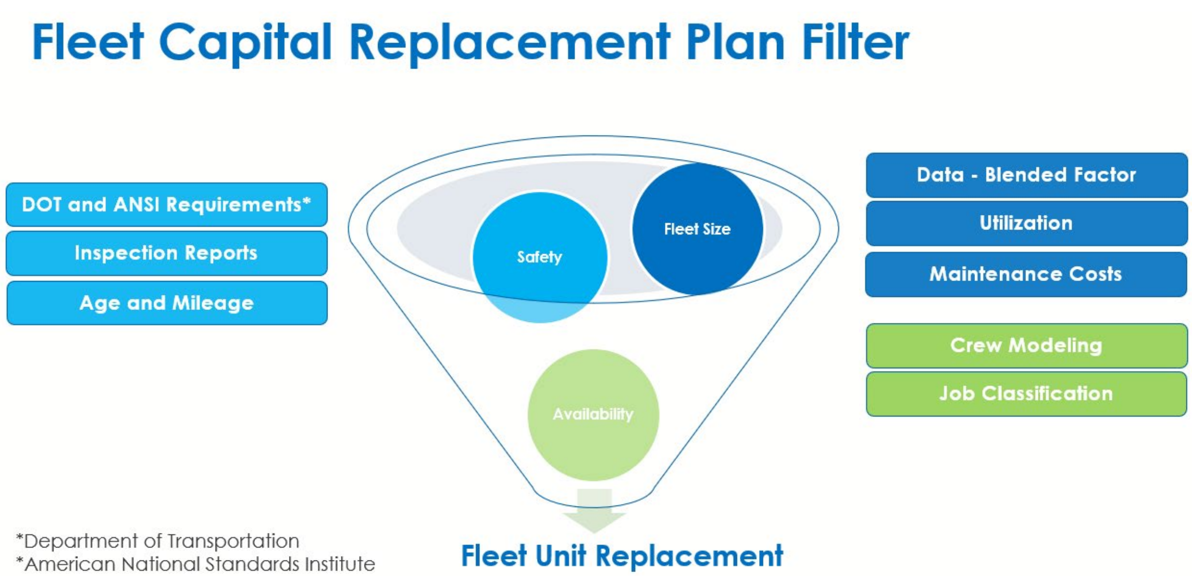
II. FLEET REPLACEMENT PLANNING PROCESS

Q. What is the Company's overall Fleet Replacement Planning Process as it is being presented in this case?

A. As previously presented in Electric Rate cases, Case Nos. U-21224, U-20963, U-21389 and Gas Rate cases, Case Nos. U-21148, and U-21308, the Company develops its Fleet Vehicle Capital Replacement Plan using the Fleet Replacement Planning Process, which is a process that incorporates three phases. In the first phase, the Company identifies vehicles that are at or near the end of their expected life and are eligible for replacement, using a tool called the Blended Factor that is described in more detail below. Next, in the second phase, the list of vehicles identified by Blended Factor Analysis for potential replacement is further developed by certain data tools, described below, particularly by fleet cost data, followed by crewing data, and, lastly, fleet utilization data. In this second phase, the Company's fleet leadership also worked with Operations leadership and personnel in the field, which includes operators and mechanics, to identify which specific units should be replaced, incorporating qualitative inputs like maintenance reports and local area work needs. This second phase allows for further evaluation of the vehicles identified in the first phase to better determine which vehicles should be replaced. Thereafter, in the third phase, the list of vehicles identified for retirement is finalized based on the evaluations performed in the first two phases, and the ordering process begins. If an existing contract is already in place, orders are placed immediately with the manufacturer or vendor. For vehicles not covered by an existing contract, detailed specifications are written and requests for proposals are sent out to vendors (including minority-owned and Michigan-based businesses whenever possible). Once bids are received, they are evaluated and awarded based on cost, product support, and quality.

Q. Please further explain how the Company establishes its Fleet Replacement Planning Process.

A. The Company strives to replace assets at the optimal moment in the vehicle's service life by incorporating several factors in the decision-making process, particularly within phases 1 and 2. In doing so, the Company uses data gathered for each spec that is documented, monitored, and corroborated with detailed in-person inspections. Data is generated by the fleet through Telematics, including utilization rates, fleet age, and detailed inspections as a basis for determining future fleet purchases of specific capability and utility. The Company's process for compiling and analyzing qualitative and quantitative inputs to develop its Fleet Vehicle Capital Replacement Plan is illustrated by the "filter" shown below.



Q. Please explain how the Fleet Capital Replacement Plan Filter works.

A. When the Company goes through its Fleet Replacement Planning Process, specifically within phases 1 and 2, certain data – such as the Blended Factor, utilization, operating cost, and crewing needs – is analyzed to determine if a given vehicle needs to be replaced. During the Fleet Replacement Planning Process, other qualitative inputs like vehicle inspection reports and the assessments of field employees provides further insight on replacement needs. The result of this process, specifically following the first and second phase, is a list of fleet units to be replaced.

Q. Can you describe, in further detail, the Blended Factor used in phase 1 and the Fleet Cost Tool, Crewing Model Tool, and Fleet Utilization Tool used in phase 2?

A. Yes. These are each described in the following sections:

A. Blended Factor

Q. Please further explain the Blended Factor.

A. The first step in the Company's process for establishing its Fleet Vehicle Capital Replacement Plan is informed by the Blended Factor. As previously mentioned, the Blended Factor takes age, usage, and mileage into consideration and establishes a replacement priority for units that are more economical to replace than continuing to maintain. The Blended Factor for any vehicle is calculated as shown in the illustrative example below:

Blended Factor Calculation

$$\text{Blended Factor Rating} = \left(\frac{[\text{Age Factor} + \text{Usage Factor}]}{2}\right)$$

$$\text{Age Factor} = \left(\frac{\text{Actual Age in Months}}{\text{Expected Life in Months}}\right) - 1$$

Example: $\left(\frac{102}{84}\right) - 1 = .21$

$$\text{Usage Factor} = \left(\frac{\text{Estimated Mileage}}{\text{Expected Life Mileage}}\right) - 1$$

Example: $\left(\frac{223{,}180}{150{,}000}\right) - 1 = .488$

Blended Factor Example: $\left(\frac{[.21 + .488]}{2}\right) = .349$

Equipment and engine operation hour calculation: 1 hour = 25 miles

For equipment that does not have mileage (no odometer), the Blended Factor calculates usage from the engine hours. For medium and heavy-duty vehicles, the Blended Factor calculation also uses total engine hours, assuming that one hour of engine operation is equivalent to 25 miles of travel. Using this calculation, a Blended Factor result greater than 0.00% indicates that a vehicle is at or past its expected life and is, therefore, eligible for consideration for replacement. This indicator does not mean that a vehicle with a result greater that 0.00% is automatically selected for replacement; it is instead a *starting point* each year for the Company to use as a foundation in the selection of vehicles for replacement.

Q. Why is it important for the Company to consider the expected life in months and expected life in mileage for each of the respective specs?

A. The Blended Factor formula incorporates two key indicators of how a vehicle reaches the end of its expected life: (1) how old a vehicle is, and (2) either how many miles it has traveled or total hours of operation. Expected Life in Months considers manufacturer inputs, reliability, operating conditions, and operating cost to determine the duration the Company expects a vehicle to operate safely and cost effectively. Expected life in mileage or hours is also based on similar considerations as an indicator of wear and tear. The Company makes these evaluations to set a foundational benchmark to assess potentially replaceable vehicles. The fleet has a diverse range of specs for specific operational needs, and not all specs have the same expected life. Even within the same spec, individual units can vary in condition depending on utilization and wear. Managing each spec to its appropriate expected life ensures that the Company always has the right type of vehicle available to serve the needs of customers in the safest, most reliable, and most efficient manner possible, while minimizing costs.

Q. Why is the use of the Blended Factor appropriate?

A. The Blended Factor is an internal data-based algorithm that incorporates unit age, utilization (in mileage or hours), and expected life, allowing the Company to prioritize, plan, and target specific vehicle(s) for replacement. As a key feature of the *first phase* of the replacement process, the vehicles denoted by the Blended Factor to be approaching the end of their expected life provide the basis for planning phases ahead. This process is critical to assure that the Company can order a timely unit replacement, especially given the supply chain challenges that have emerged in the last three years. While there has been some improvement in the expected delivery dates for some products, planning around potential delivery delays and availability is still a concern as demand for new medium and heavy-duty equipment remains high. By using the Blended Factor, the Company can strategize future spending for replacement units for specific years by consulting with suppliers on current and future availability, thereby preparing the Company to order units given current lead times to receive a unit once an order is placed.

Q. What conclusions do you draw regarding the Blended Factor?

A. The Blended Factor provides an objective standard that uses clear internal fleet data to identify units for potential replacement and adds a level of predictability regarding which units will need to be replaced to improve the cost-effectiveness of the replacement process. Based on the above Blended Factor calculations, it is indicated that out of approximately 7,340 units currently in the fleet, there are approximately 2,000 units greater than 0.00%.

B. Fleet Cost Tool

Q. Please explain the Company's fleet cost tool.

A. As part of the second phase in its Fleet Replacement Planning Process, the Company is utilizing the fleet cost tool, incorporating data analytical tools to support near- and long-term cost-effective vehicle purchase plans. These analytical tools include tracking vehicles by spec and the average age of each spec, fleet operating and maintenance costs, and geographical location. Additionally, the fleet cost tool provides at-a-glance total and average per-vehicle operating costs for each spec from various perspectives, including operating costs per mile, by age, and by specific vehicle. These tools provide data indicating vehicle count and average age, broken out by spec for 2016 through the initial point of analysis in 2023, and the Company will continue compiling data going forward. The purpose of these tools is to provide overall cost status summaries of the fleet, as well as a platform to perform more detailed cost analyses of individual vehicles. The following are descriptions of several tools the Company has developed.

Q. What are these tools that the Company has developed to support fleet cost analyses?

A. For an overall summarization of fleet age and operating costs, the Company has developed "Unit Age and Operating Cost" and "Unit Count and Average Age" tools to provide information regarding fleet operating costs correlated with age. Operating costs include maintenance, fuel, and repairs. This information can be filtered by vehicle year and spec and can assist in identifying trends that will enable cost forecasting to support future purchasing decisions.

Q. What are additional analytical tools related to fleet cost?

A. The Spec Detail Information Analysis identifies equipment count by spec and is designed to highlight yearly fleet growth by spec, which helps identify trends and how the fleet's makeup and size changes over time.

Q. Are there any other analytical tools that are part of the fleet cost tool?

A. The Age and Cost Spec Detail Analysis is designed to provide detailed cost information for a specific unit, including total operating cost, as well as average costs over time for specific specs. In this analysis, the Company evaluates equipment count, total operating cost, average unit operating cost, median unit operating cost, and average unit age. Finally, a Location Summary Analysis displays a particular territory, city, spec, equipment count, and total operating cost for vehicles distributed throughout the Company's service area. Equipment Count by location is displayed on a map with circle size indicating high/low equipment counts and color indicating zone. Average Unit Age and Total Operating Costs are summarized in cards at the top of the page. This page allows the user to filter on Year, Usage Indicator, Rental Status, and Spec. The purpose of this tool is to allow the user to use the filters to summarize equipment count, cost, and age by location.

Q. Why are these fleet cost analytical tools appropriate for the Company to use?

A. Using the Company's own data, the information these tools provide is used to help the Company plan the cost-efficient replacement and acquisition of new vehicles. The Fleet Cost Tool data provides information from several perspectives that helps narrow the pool of vehicles identified by the Blended Factor for replacement. For example, the Blended Factor may identify many units within any given spec that are at or near the end of their expected life, but a further examination using this tool can help inform how the unit is performing in relation to other identical spec vehicles in the fleet from a cost perspective. If the unit has become uneconomical to operate compared to other vehicles in the same spec, it may be best to replace that vehicle for a more cost-effective solution sooner rather than later. Conversely, a vehicle that has reached the Blended Factor end of expected life may still have years of economical service possible based on operating cost reported by these tools. This fleet cost tool also allows the Company's fleet management to understand how fleet costs have changed year-over-year, including the ability to examine costs of specific units to help inform if they are good candidates for replacement. The tool is intended to provide an overview of past fleet metrics, and helps to identify relationships between unit age, mileage, and operating costs. It also shows fleet age by spec which can be helpful when multiple units of the same spec were purchased in the same year. This is important information to consider when prioritizing the most appropriate vehicles to replace at any given point for the benefit of customers.

Q. What has the Company learned to date from using its fleet cost tool?

A. The fleet cost tool has allowed the Company to make informed decisions while reviewing units identified for replacement. This tool provides the Company with an at-a-glance total of overall costs for each particular unit. As the fleet team strategizes how and where to replace vehicles, the cost tool assists in framing how to best benefit the customer in the decision-making process.

As noted, the Blended Factor calculation is a starting point in the decision-making process, with the expectation that the list can be modified as further analysis proceeds. The cost tool facilitates a review of repairs and improvement costs associated for each vehicle that can extend its service life. For example, feedback sought and received from field leaders on the overall condition and serviceability of a truck can show that it should be kept in service instead of being replaced. This includes investments like engine or transmission rebuilds, or body rust repairs. The fleet cost tool quickly identifies which units require closer scrutiny when making purchasing decisions. This benefits the customer in that the Company gets as much service life out of units as is economically prudent.

C. <u>Crewing Model Tool</u>

Q. Please explain the Company's crewing model and crewing model tool.

A. As part of the second phase of its Fleet Replacement Planning Process, the Company's crewing model is used to calculate how many vehicles are needed based on the size of the workforce. This model incorporates all gas department vehicles and details about what employees are assigned to operate these vehicles. The gas department includes Gas Services, Gas Distribution, Gas Construction, Gas T&S, and Gas Compression. These departments operate the following types of units: Medium Duty Crew Trucks, Dump Trucks, Crane Trucks, Prentice Loaders, pickup trucks, vans, other various support vehicles, and construction equipment and trailers. The crewing model tool illustrates how many vehicles are needed and how many vehicles are available, giving visibility to gaps if any are present.

Q. What information does the tool show?

A. The tool lists Company locations and, for each location, shows the number of units at that location by workgroup, breaking down the number of employees and the number of different types of units located there. Based on this information, the tool provides the gap between actual number of vehicles at the location and the number of vehicles needed.

Q. How was this crewing model developed?

A. The Company's Gas Operations department's workforce size and crewing influences the number and types of vehicles needed to serve customers. Crewing is determined by the work required and influenced by safety and policy procedures related to the work performed. In the crewing model, the Company uses standard crewing of the following truck to employee ratios:

- Gas crewing consists of one Gas Line Worker ("GLW"), one Trenching Machine Operator ("TMO") to make one crew. Each crew is assigned a Gas Service Truck (spec 44) and a support vehicle. The support vehicle could be a dump truck or a pickup. The crewing model calculates vehicle needs according to the following ratios:

Vehicle Type	Model Ratio
Gas Service Truck (spec 44)	1:1 TMO to Gas Service Truck
Digging Equipment	1:1 GLW/TMO to Digging Equipment
Pickup	1:1 GLW to Support Vehicle
Fillet Welder (Spec 28)	1:1 GLW to Fillet Welder

- Employees in Gas Meter Operations, Customer and Field Services, usually operate as single workers, rather than in a crew, meaning they have a 1:1 vehicle ratio.

Q. Why is this crewing model appropriate for the Company to use?

A. The crewing model is based on industry best practices and Occupational Safety and Health Administration ("OSHA") requirements[1]. To provide a safe, reliable, and cost-effective fleet, it is important that the Company's fleet be adequate in size to complete the established work plan, work safely, and adhere to OSHA requirements.

Q. What conclusions can you draw from the data shown in the crewing model tool?

A. The model shows that the quantity of production units (gas service trucks, excavators, back hoes, trenchers and directional drills with associated trailers) currently in the Company's fleet will continue to be evaluated based on established work plans and employees needed to perform the work (more information on how utilization data is calculated is provided in the next section of this testimony). The model can help identify surplus or deficiency of assets in each specific area and units that are down for repairs or regular maintenance. This visibility allows the Company to reallocate surplus assets to areas with deficiencies to ensure each area is adequately supplied based on the model. Backup vehicles must be ready to meet the needs of the crews as daily schedules develop, meaning that some additional vehicles may be needed on short notice. The Crewing Model allows for backup vehicle availability for such circumstances to reduce the risk of gaps between crews and vehicles needed in the field.

The crewing model assumes the Company will onboard new or add replacement workers consistently and in a timely manner as work plans develop to drive the need for

[1] https://www.osha.gov/laws-regs/regulations/standardnumber/1926/1926.651

workers and as attrition rates affect the workforce. However, due to supply chain issues and the current labor force situation, the Company does not always receive new vehicles at the same time new workers are onboarded. For this reason, it is possible that new vehicles will be received and paid for before workers are ready to use them, but those vehicles *will* be put into use once the planned hiring is complete. Utilization rates for vehicles may at times reflect this reality.

Q. What has the Company learned to date from using its Crewing Model?

A. The Crewing Model offers the ability to find gaps in available units, and much like a checklist, allows the Company to proactively prepare for any emerging vehicle needs based on how new projects and employees are planned or deployed. In this manner, the Crewing Model complements the other fleet tools the Company is developing by ensuring that units are allocated as effectively as possible before and after any new units are purchased. The customer benefits from this because the Company is constantly working to keep its fleet right sized, with as little redundancies as possible.

D. <u>Fleet Utilization Tool</u>

Q. Please explain how the Company captures utilization data for its fleet.

A. All vehicles use a Telematics device that is directly wired to that asset's onboard computer or switching. Each installed Telematic device communicates, via cellular signal in real time, information about the asset status including the unit's exact Global Positioning System ("GPS") location, date, time, mileage driven, and hours in operation. A vehicle is considered in use for any given day when it has traveled five or more (5+) miles at any time or equipment that is in operation for thirty or more (30+) minutes per day. This captured data is then uploaded and compiled on a nightly basis into one tool that can then be used to run reports as needed to manage the operation. This data is compiled into a fleet utilization tool that can provide fleet use by zone, by vehicle type, or department and is used as part of the second phase in the Fleet Replacement Planning Process.

Q. How was this data process developed?

A. The electronic information captured by the Telematics system documents industry standard data points that are used to log key vehicle information. Since 1996, every vehicle manufactured in the United States has an On-Board Diagnostic ("OBD") port/interface that can easily be made accessible to Telematics systems and their associated electronic data gathering capabilities. The OBD system provides access to a vehicle's Electronic Control Unit, the main computer that controls vehicle engine, transmission, and other key vehicle functions. By connecting directly to the OBD of each vehicle, the Telematics system is able to collect the real time information required to inform the Company to log the key data points required to document utilization.

Q. How is the Company's utilization data tied to the crewing model?

A. As explained in the crewing model section, vehicles are assigned in response to the requirements of the daily work plan and the employees needed to complete the work. Some types of vehicles, like bucket trucks, are used frequently for common field operations, whereas there are other types of vehicles that are highly specialized and designed for specific tasks that are not always required on a given day/night to serve customers but are no less crucial to properly service customers throughout the state. The Company's utilization data also accounts for the downtime that equipment must undergo when receiving inspections, maintenance and repair, or other ancillary equipment upgrades, and for the fact that some equipment must be available for on-call assignments and off-hour assignments.

Q. Why is this approach to utilization data appropriate for the Company to use?

A. By capturing real-time telematic data from each asset and compiling it in one dataset, the Company obtains the required raw data to detail the exact frequency, duration, and overall use of each asset, and this data is then searchable for reporting utilization rate purposes. Utilization data can illustrate where units may be underutilized. The customer benefits from this approach because the Company ensures that all vehicles and assets are tracked, monitored for maintenance and safety, and allows for the optimal cost-benefit relationship and return on investment for its fleet. This approach supports the analysis of what assets the Company needs to purchase to be sure that it is replacing vehicles at the end of their lifecycles, and to be sure that the Company is serving customers with safe, capable, and effective equipment.

Q. What conclusions do you draw from the Company's fleet utilization data?

A. The Company's utilization rate data informs us that a continual review of fleet equipment for under-utilized vehicles, what areas of the business they serve, and how that may impact the Company's ability to serve its customers, will be on an ongoing analysis. It is a key tool in determining why and where vehicles may be down (or showing lower utilization rates). For example, vehicles that are down for repair or awaiting parts are different from vehicles that are available but are not being used to serve customers when evaluating utilization rates. The Company analyzes its fleet utilization to determine if there are any redundancies that can be dispositioned in the future, such as through attrition and reallocating to raise utilization to more optimal levels.

E. Benefits

Q. Please summarize the Company's Fleet Replacement Planning Process.

A. The Company's fleet consists of 7,340 units of varying specs utilized for specific tasks to serve customers, divided between the electric and gas sides of the business. Assets referred to as "common units" are utilized by various other departments within the company to support business operations. The Company employs a Fleet Replacement Planning Process (Replacement Filter, Blended Factor, Cost Data, Utilization Data and Crewing Models) to determine, in the most cost-effective and efficient manner, which units to replace. The Blended Factor identifies a pool of assets to consider replacing based on the mileage and age of each asset. Fleet cost data helps refine the initial group of eligible vehicles by helping to identify units that have become more costly than their value, or inefficient to maintain in the fleet. By applying crew modeling and utilization analysis, the Company checks to ensure that crew sizes support the potential number of vehicles replaced or added and confirms that replacement assets are appropriate based on usage rates. The customers benefit from this overall process because the systematic efforts noted above attempt to replace and/or add fleet assets at the most beneficial time possible. Each step in the process is designed to specifically identify which assets to add or replace, and the rationale and timing.

Q. What are the benefits of the Fleet Cost Tool for customers?

A. The tool helps the Company make decisions about which units should be replaced or kept by illustrating when the cost of maintaining the units outweighs the cost of a new unit, or investments made in units to keep them in service, which ultimately supports decisions made in the Company's Fleet Vehicle Capital Replacement Plan. The tool allows for visibility in significant investments such as a new engine or transmission in a vehicle that could extend its service life. The customer benefits from this analysis because the Company is using fleet dollars in the most economical way possible.

Q. What are the benefits of the Crewing Model for customers?

A. Having the ability to tie the workforce to the right vehicle by location enables the Company to have visibility to align assets with the workplan by department and location. As the Company strives to be good steward of the fleet, the model helps validate if additional units are needed to meet the Company's workplan or, alternatively, if the Company has any surplus units that can be redeployed or retired. Absent this, the Company may end up lacking the appropriate vehicles to complete work for the customers' benefit.

Q. What benefits does fleet utilization data provide for customers?

A. Peak utilization of all vehicles is a balance between fully utilizing purchased assets and having the right asset in place and ready when needed at a moment's notice when responding to outages, new business, or construction situations.

Fleet assets that are underutilized are not providing the maximum benefit to the customer. As good stewards of its fleet, the Company must provide the most cost-effective methods to assure that the fleet is a safe and effective part of the service it provides. The Company's ability to serve its customers reliably, efficiently, and to a high standard requires an equally capable fleet. By methodically incorporating utilization processes that monitor fleet assets, the Company can maintain the fleet to manufacturers' specifications, as well as addressing the periodic wear and tear that comes with operating vehicles in often extreme conditions.

Utilization data that monitors each type of vehicle can also assure that the Company is earning the best return on investment for the expected environment said vehicle is designed to operate in. For example, the Company expects that investing in a sedan should provide a life expectancy of seven years and approximately 150,000 miles under normal service. Utilization for a vehicle of this type may differ as compared to a utility truck sent as needed to address concerns in the field or support customers as the need arises. However, for both types of vehicles, regular monitoring of utilization reports will help the Company plan for the replacement of each vehicle with regular use over time. Additionally, analysis of any under-utilized vehicles will inform decisions on how many future investments in that type of vehicle are made going forward. Customers benefit when the Company is making best use of its fleet to deliver service. Utilization data helps the Company right-size its fleet by identifying where additional units are needed to accommodate the Company's workforce, if there are any surplus units, and if existing units can be more effectively used by the Company, such as by moving units to a new location or new department.

Q. Have there been right sizing efforts that benefit the customer?

A. Yes. Since early 2022 the Company has reduced its total number of units by approximately 500 units utilizing the tools described above. These right sizing efforts benefit the customer by reducing overall cost through reductions and/or allowing a particular unit to be effectively utilized in support of serving customers.

Q. How does the Company's overall Fleet Vehicle Capital Replacement Plan benefit customers?

A. Overall, the Fleet Vehicle Capital Replacement Plan allows the Company to retire and replace vehicles in a cost-effective way by using qualitative and quantitative inputs to identify units for replacement, particularly by identifying those units with high maintenance costs and exhausted expected useful lifespans. Retiring and replacing those units in a systematic way is designed to keep maintenance costs down while ensuring that vehicles are available when needed to serve customers. The replacement planning process is a constant, self-evaluating cycle that relies on the data the fleet itself generates over time (mileage, age, and life cycle expectancy), inspections, maintenance and repair costs, and the local expertise to assist in prioritizing how the Company replaces units in the fleet. The customer benefits from this replacement planning process because the fleet is a crucial part of the overall service the Company provides. A replacement plan allows the Company to provide a safe, reliable, and cost-effective fleet to respond timely to utility outages, damaged utility service, utility service renewals, and new construction requests.

Q. Are there further benefits related to safety, quality, and the planet when determining the Fleet Vehicle Capital Replacement Plan?

A. Yes. By replacing vehicles in the fleet, newly introduced features from vehicle manufacturers are regularly incorporated into the Company's fleet, such as the following:

Safety-

- Backup sensors and rear-view cameras. This feature allows for safer backing, resulting in fewer rearward collisions, reducing vehicle and property damage, and increasing safety for the Company's customers and employees as well as collision avoidance and auto emergency braking, reducing collisions by advanced driver warning and applying brakes in advance of collision.

- Reduced stopping distance requirement from the Federal Motor Carrier vehicle safety standard for class 6-8 trucks. The standard distance required to stop a commercial vehicle was reduced, (National Highway Traffic Safety Administration 49 CFR Part 571, requiring a 30% reduction in stopping distance compared to currently required levels), which led to equipping trucks with larger braking systems to avoid collisions on buses and trucks manufactured on or after July 1, 2005.

- Light Emitting Diode ("LED") headlight technology. This allows a driver to see further down the road giving the driver more time to react to a situation. LED headlights also save money due to less frequent bulb changes, thereby reducing time under repair.

Quality-

- Materials to manufacture vehicles are continuously advancing. For example, the Ford F-150 body is now stamped out of military grade aluminum, making the truck lighter, which increases fuel economy. Another added benefit of aluminum bodies is corrosion resistance, meaning less time and money spent repairing corrosion problems.

- Over the last 10 years, diesel engine exhaust gas recirculation coolers have improved, eliminating the need to replace them as frequently. This saves approximately $4,000 per replacement, where such replacements were occurring about every two years.

Planet–

- To align with National Highway Traffic Safety Administration's corporate average fuel economy standards, new vehicles are becoming more fuel efficient to align with their regulations. When replacing units within an appropriate lifecycle, the Company has an opportunity to purchase more fuel-efficient vehicles, including fully electric and plug-in hybrid vehicles where appropriate, ultimately reducing the Company's carbon footprint.

- Fossil fuel powered vehicles may be replaced with an electric vehicle ("EV") if data supports electrification in that instance and could be a more fuel-efficient mode of transportation.

III. FLEET ELECTRIFICATION STRATEGY

Q. Does the Company plan to increase the number of EVs in its internal fleet?

A. Yes, the Company plans to increase the number of EVs in its fleet to reduce fleet fuel, maintenance, and operating costs, as well as lowering carbon dioxide tailpipe emissions to reduce greenhouse gases. For purposes of this testimony, the Edison Electric Institute's definition of an EV includes all vehicles with a plug, including Battery Electric Vehicles, Plug-in Hybrids, and anti-idle job site work systems such as electric Power Take Off systems (ePTO) units.

Q. How many EVs does the Company have in its internal fleet currently?

A. The Company's fleet currently operates approximately 268 EVs, representing 4.6% of powered units in the overall fleet.

Q. Does the Company have a target goal for electrification of its internal fleet?

A. Yes, as noted by the Michigan Council for Future Mobility and Electrification in its 2021 report, the decade ending in 2030 will be notable in that the growth of EVs in the state will present new opportunities for the Company and its customers.[2] Company witness Jeffrey A. Myrom, in support of the Company's PowerMIDrive and PowerMIFleet pilots and programs, discussed the growth of EVs in Michigan and the Company's service territory in his direct and rebuttal testimony in the Company's ongoing and past electric rate cases (see, e.g., Case Nos. U-21389, U-21224, and U-20697). The PowerMIDrive and PowerMIFleet programs have been designed to allow the Company to stay ahead of the growth of EVs in Michigan to allow the Company to learn and manage the electric grid with that EV growth. With the advancement of the PowerMIFleet program, the Company can not only learn from customer fleets, but can also lead by example; thus, the Company has set a goal of electrifying 30% of its internal fleet by the year 2030, including light, medium, and heavy-duty vehicles (class 1 through class 6 and higher), equipment and powered trailers, as well as electrifying all class 1 and 2 (light duty) vehicles after 2030.

[2] cfme_report_2021_02.pdf (michigan.gov)

Vehicle electrification programs have primarily been the topic of discussion in the Company's ongoing and past electric rate cases, and the Company's use of EVs for its fleet was recently introduced in the Company's ongoing electric rate case. Purchases of EVs, however, are now relevant to the Company's gas rate cases, including this gas rate case, as some of the fleet, and the associate charging infrastructure, will be used, in whole or in part, for gas operations. As discussed below, replacement of ICE vehicles with EVs also has other benefits, beyond the goals of the PowerMIFleet program.

Q. How many vehicles does the Company plan to convert to electricity as a source of fuel by 2030?

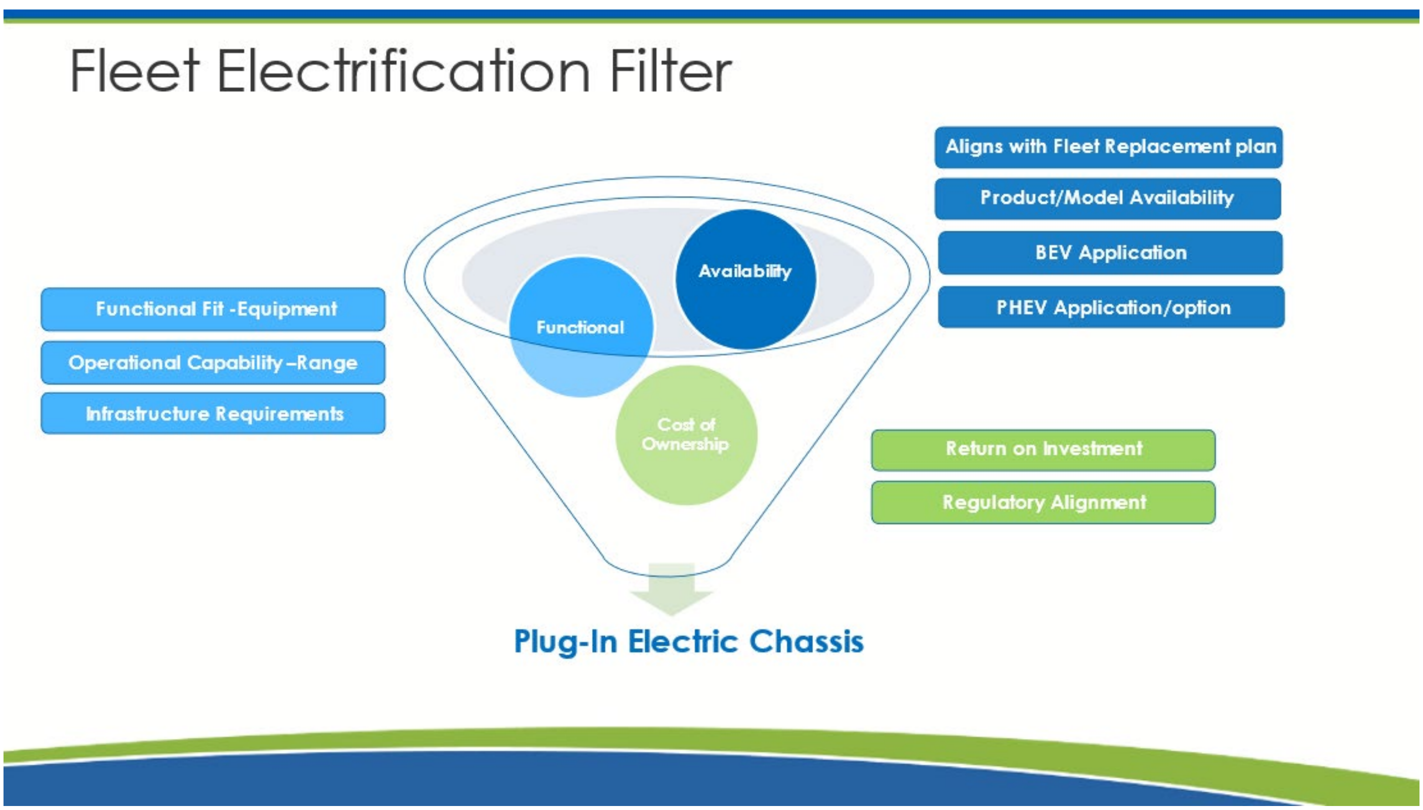
A. The internal fleet currently consists of approximately 5,700 powered vehicles eligible for replacement by potential EVs. This includes sedans, pickup trucks, bucket trucks, forklifts, and others. Electrifying 30% of these units would result in the replacement of approximately 1,700 internal combustion engine ("ICE") units with a fully or partially EV powered units by 2030.

Q. What types of vehicles does the Company expect to replace with EVs?

A. The Company expects that most of the initial ICE vehicles it will replace will be sedans and pick-up trucks; however, as battery technology develops, there will be increasing availability for medium and heavy-duty vehicles to enter the market. For example, the Company has already committed to purchasing one of the first available all electric bucket trucks in the world, scheduled for delivery first quarter of 2024. The Company is currently assessing which location will work best to deploy its first all EV bucket truck and will plan to upgrade the location's electrical infrastructure for a DC Fast Charger to support it.

Q. How will the Company determine opportunities to replace ICE vehicles with EVs?

A. The same replacement process, as discussed earlier in my testimony, will be used to determine opportunities to replace ICE vehicles with EVs, including the use of the Blended Factor, unit age, and overall condition analysis for each unit that has reached its end of life. Under this process, as a unit is targeted for replacement and reviewed according to the Replacement Plan, the unit is also considered for replacement with an EV. As the Electrification Filter shown below illustrates, consideration for electrification includes assessing a suitable replacement that is available in market, would have a functional role within the fleet, and lower cost of ownership. If the ICE under consideration for replacement meets the criteria required to pass through the filter, the unit is considered as an opportunity for replacement with an EV.



Q. Why is the Company concerned by fucntional fit and equipment considerations?

A. The Company partners with operational departments to understand how the potential replacement of an ICE vehicle with an EV will impact how teams complete their work. It is important to understand vehicle travel patterns, including mileage and driving duration, to assure that EVs are capable of supporting the work and have the travel range the Company needs to serve customers without compromise.

Q. Why is the Company considering range concerns with electric vehicles?

A. As noted above, mileage range is a top consideration in determining how the Company integrates EVs into the fleet. It is critical to understand how current vehicles operate to determine potential EV replacement options, as well as infrastructure preparedness. The Company is utilizing its trip data, including mileage and location, to understand the best fit for each EV it is considering.

Q. Why is functional fit a critical part of the EV decision making process?

A. As with all other vehicles, the Company strives to ensure its Fleet aligns with industry best practices to serve the customer safely and efficiently. It will be important to consider, in addition to range, how an EV will support each department's ability to use it to its fullest capabilities, such as carrying tools and employees as required by the work.

Q. How will the Company determine if EVs are performing as expected?

A. The Company will be expanding its internal focus groups to provide real world feedback on barriers and opportunities to continuously improve how the Company adapts EVs in various operational environments.

Q. In what ways are EVs more beneficial than ICE vehicles?

A. Most of the benefits gained from utilizing EVs or battery-assisted systems arises from the changeover to electricity as the main source of energy, instead of gasoline or diesel fuels and petroleum-based maintenance materials. Electric motors require much less powertrain maintenance and repair, resulting in reduced maintenance costs, which is one of the key benefits of electrifying fleet units. A fully EV (battery) powered vehicle can also have up to 80% fewer parts than its ICE counterpart. With fewer internal parts, electric motors operate with less friction and more efficient use of energy. Many ICE vehicles parts require frequent and costly maintenance routines. Further, up to 65% of the heat energy produced by an ICE is wasted, requiring cooling systems which are prone to wear and eventual failure.

Q. Can you please give examples of reductions in maintenance that will arise out of a transition from ICE vehicles to EVs?

A. ICE vehicles contain hundreds of oil-lubricated parts that are required to convert the combustion of fossil fuels into the mechanical energy. Fluid changes extend to other components needed at various intervals in addition to engine and transmissions, including transfer cases and differentials throughout the life of all ICE vehicles. All these systems require regular maintenance and the associated costs in labor, parts, and materials to keep them at optimum performance and longevity. Over time, however, these components continue to wear even with diligent maintenance. This wear often leads to overheating issues, damaged or broken hoses, worn coolant pumps, or engine failure with the associated down time while undergoing repairs. EVs, on the other hand, do not require oil changes, spark plugs, fan belts, or tune ups. EVs also do not have transmission fluids that require periodic fluid changes, which makes them less prone to failure. Further, since an EV drive train requires less attention from a maintenance perspective, there is a reduced need for labor and/or material costs associated with this aspect of maintaining an EV. Plug-in EV hybrids often work with an ICE in conjunction with electric motors, reducing the fuel requirements for units equipped this way. Depending on the vehicle's configuration, a hybrid that features an ICE may need a maintenance schedule like a regular ICE vehicle; however, in most cases, plug-in hybrids help reduce overall fuel consumption with extended periodic maintenance requirements.

Q. Are there other tools available to reduce fossil fuel consumption in ICE vehicles?

A. Yes, there are idle-mitigation technologies, using plug-in battery systems, designed to reduce fuel consumption by reducing idle hours required to operate ancillary equipment such as cab climate control in a gas service truck. By employing a plug-in battery and electric motor, for example, ePTO units (electric power takeoff) can power hydraulic systems for short periods, reducing fuel consumption and engine wear. When engaged at a jobsite, an ePTO system can shut an idling engine off, and a battery-powered motor then runs the systems needed to power the climate control system in the cab. As a result, the truck can operate quietly, keeping the truck's cab at an optimal temperature during harsh weather conditions. The crew can perform work near a customer's home quietly because the sound of an idling diesel will not be present while the ePTO system is engaged. The Company already employs this technology to help reduce idling hours on several specs that operate booms on bucket trucks and cabin climate control. Additionally, ePTO systems can reduce fleet's overall carbon dioxide tailpipe emissions, and as well as diesel particulates.

Q. Has the Company undergone a concierge cost benefit analysis to help plan for internal EVs?

A. Per Case No. U-20963 the Company has partnered with CALSTART, a national non-profit with over 30 years' experience in the private and public sectors with a proven track record working with over 280 member companies and agencies to build business cases for clean transportation technology adoption. CALSTART is a nationally respected team of fleet electrification experts who were selected by the Company via a competitive Request For Proposal. CALSTART has completed numerous fleet electrification assessments for external customers, in addition to the Company's. The assessments analyzed the Company's light duty fleet vehicles, by location, daily miles driven to provide approximate load demand by location, electric vehicle location recommendation based on miles driven, carbon avoidance, and a cost-benefit analysis.

Q. Does the Company solely rely on the CALSTART assessments for determining what electric vehicle to purchase?

A. The Company does not rely solely on the assessment in its planning for EVs. CALSTART used the Company's own fleet-generated data to compile a list of recommendations for vehicle locations that are potentially suitable for electrification, the estimated load demand for those locations, and the associated charging information to support them. This information assists the Company during the decision-making process when considering EVs.

Q. What quantifiable benefits of electrifying vehicles did CALSTART's assessment determine?

A. CALSTART's assessment, noted above, concluded that the Company has the potential to lower Fleet's overall fuel and maintenance costs by approximately 70%, excluding vehicle purchase price, combined over the lifetime of the vehicles that are electrified. The assessment also forecasts that the Company would reduce CO2 tailpipe emissions by approximately 90,000 metric tons.

Q. Did the assessments provide suggestions for EV infrastructure support?

A. The assessments provide specific location-based electric load demands estimates for the light duty EV's planned for replacement, as well as electricity as fuel cost estimates based on current mileage driven by ICE vehicles. For each service center/office location, the Company's ICE light-duty fleet data was analyzed for average daily miles driven and applied this information to determine the appropriate level of charger (Level 1 or Level 2) and the estimated corresponding energy demand for each vehicle. With this information, the Company can plan for the specific infrastructure electrical upgrades needed to support the installation of Electric Vehicle Supply Equipment ("EVSE") at respective services centers with a measure of predictability based on the information the Company's ICE fleet has generated.

Q. Could you please provide us with an example of location-based charging information provided by the assessment?

A. As an example, for the Company's location in Clare, Michigan, the Company currently operates 14 ICE light-duty fleet vehicles that are potential candidates for replacement with EVs when those units reach the end of their useful lives. Based on each vehicle's average daily miles and expected energy use per mile of 0.346 kWh/mile, an informed approximation can be made on the energy each potential EV replacement will consume. Based on the average daily miles and expected Flat Average Hourly Power Charging Power Demand, the assessment calculates that for the Clare location the Company should expect approximately 279 kWh per day to charge EV's if all identified ICE vehicles were to be replaced with an EV.

Q. Are there other associated projects being planned to support vehicle electrification efforts?

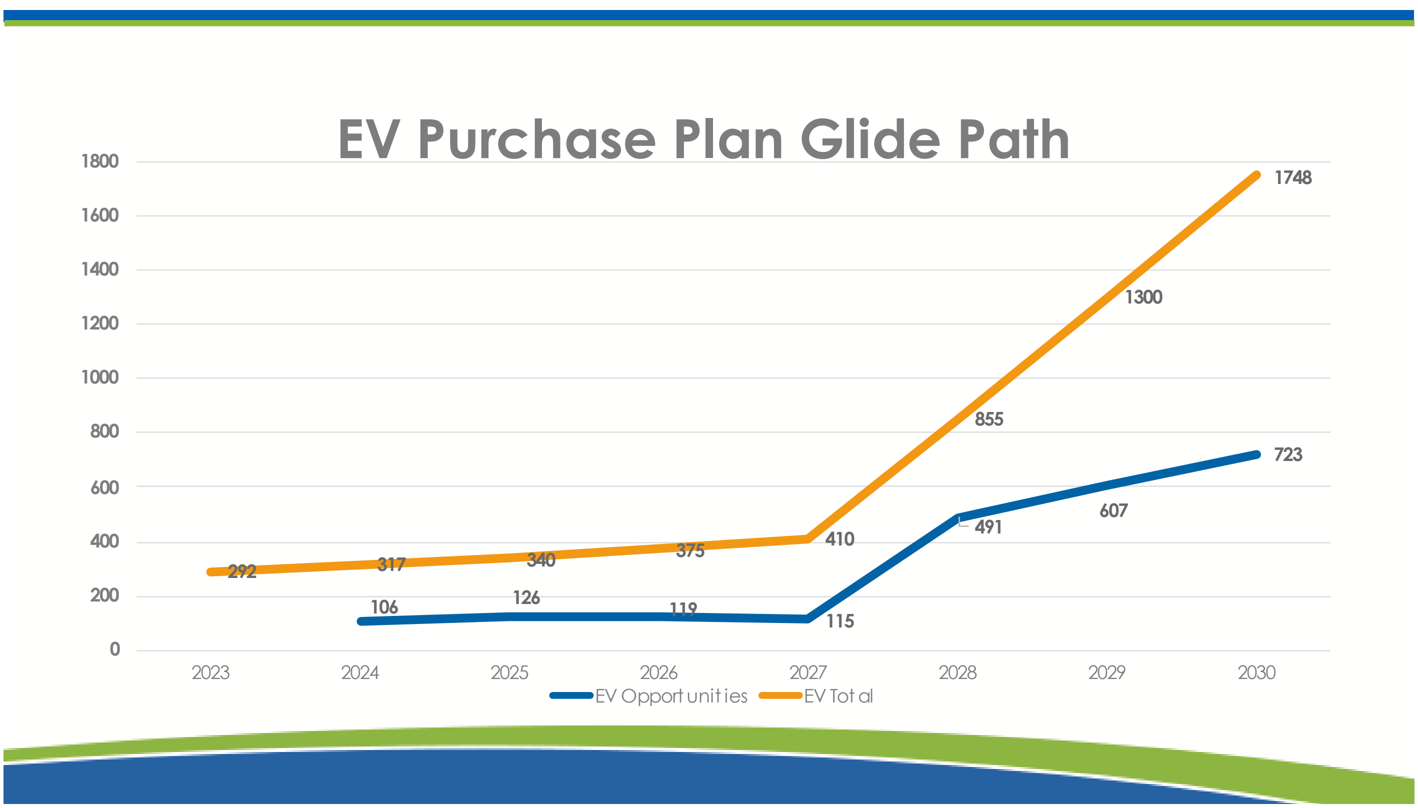
A. Yes. To support the growth of EVs, the Company must plan for the increased electric load demands at most of its service centers to charge the electric vehicle units at those service centers. Since each center location will have a varying number of EVs, each location will require a specific power demand-based upgrade of its electric infrastructure for the installation of EVSE, also commonly known as "chargers." As noted earlier in my testimony, Fleet has undergone a detailed data-based assessment to determine the load demands each facility will need to charge electric vehicles daily.

Q. How many more vehicles does the Company need to reach its goal of 30% EVs by 2030?

A. As mentioned earlier in my testimony, at current fleet totals, the Company needs approximately 1,700 units to reach the 30% goal by 2030. The Company currently operates 272 electrified units. With the addition of 21 EVs planned by the end of 2023, the total will rise to 292.

Q. How many EV opportunities are identified in the Five-Year Purchase Plan?

A. The Five-Year Purchase Plan identifies approximately 466 potential opportunities to replace an ICE with an EV based on replacing units that have reached their end of life. As illustrated in the EV Purchase Plan Glide Path below, there are 106 light duty vehicles that could be replaced with an EV in 2024, and another 126 opportunities in 2025, 119 in 2026, and 115 in 2027. With limited opportunities to make ICE to EV replacements through 2027, the Company would need to invest additional funding above the currently approved capital replacement funding for the purchase of approximately 450 EVs over and above what the Purchase Plan identifies as a replaceable unit each year in 2028, 2029, and 2030 to reach the Company's goal of approximately 1,700 EVs.



Q. Is the market for vehicle electrification currently able to supply the vehicles needed to support the Company's goal?

A. Lead times for many EVs and idle mitigation systems are often two or more years out. The resources required by manufacturers to build enough units to meet high demand are not in alignment, which has often led to short supplies for both commercial and private customers; however, the market's availability of EVs suitable as fleet vehicles is still a very small part of the EV market. Currently, a substantial portion of the fleet EV market consists of vehicles that do not meet the criteria for cost and features best suited for use by the Company. For example, the Company prefers Original Equipment Manufacturer (OEM) vehicles from Michigan based companies, such as GM and Ford, as well as meeting all the requirements noted as part of the Fleet Electrification Filter. There are many startup companies with potentially viable EV units; however, the Company prefers to limit the potential exposure to the risks associated with startup company products.

Q. How does limited availability of EVs effect the Company's glidepath to its goal?

A. The Company's ability to increase the number of EV units in the fleet remains flat through 2027. At this time, limited market EV availability may prevent the Company from ordering the suitable number of EV units needed to affect a more linear glidepath toward the 2030 goal. Additionally, the number of EV opportunities identified in the Purchase Plan averages approximately 117 units per year. If the Company continues to purchase EV units at an average of 117 units per year, the goal to electrify 30% of the fleet will not be met by 2030.

Q. What EV units does the Company plan to purchase for the Test Year?

A. The Company has placed orders for six (6) Chevrolet Silverado EV pickup trucks.

Q. How will the Company determine the locations to assign EV vehicles?

A. All EVs will be assigned to departments and teams that are best able to utilize the benefits of an electric vehicle during their daily job functions. As discussed earlier in my testimony, the assessment from CALSTART provides a summary of miles driven by location, allowing the Company to understand where an EV can be best utilized. As specific units are identified, actual mileage, location and seasonal low temperatures are utilized to help forecast range expectations. For example, where the data shows an ICE pickup truck is typically driven 75 to 150 miles per day and returns to its respective service center, that vehicle could be eligible to be replaced with an EV of similar capability and range because the data suggests a good fit for an EV. The Company can reference the trip data combined with range expectations by season to help make the most informed decisions on their deployment. The Company also partners with operations to determine if an EV will meet the requirements of their work processes at a particular location.

Q. What associated infrastructure support will the EVs ordered for the Test Year require?

A. The EV units planned will require additional vehicle chargers installed at their respective headquarters to support their charging requirements. Based on this plan, the headquarter locations that will need chargers installed are Saginaw, Kalamazoo, Livonia, and Hastings service centers.

Q. How does electrifying 30% of the Company's fleet by 2030 benefit the customer?

A. The Company's efforts to electrify a portion of the internal fleet will benefit the customer in several ways. The Company seeks to lower Fleet's overall operating costs by reducing its reliance on fossil fuels, a tactic that will bring lowered maintenance costs for reasons mentioned earlier in this testimony. By shifting the cost of refueling an ICE unit from gasoline or diesel to overnight charging, the Company can save money on fuel wherever mileage powered by fossil fuels can be shifted to lower cost charging overnight rates. Over the lifetime of these vehicles, by utilizing electricity to power 30% of the fleet, the Company seeks to leverage the relative stability and lower cost electricity offers over the more volatile cost of petroleum-based fuels and lubricants. Reducing the Company's reliance on ICE vehicles brings significant reductions in the maintenance costs associated with the upkeep of fossil fuel-based drivetrains. With fewer mechanical parts to maintain, EVs require lower maintenance budgets and fewer parts that can potentially fail over the lifetime of the vehicle.

Lastly, by lowering its reliance on fossil fuels, the Company seeks to lower its overall carbon dioxide emissions from Fleet's operations. Fully electrified vehicles have zero tailpipe emissions and, where applicable, hybrid vehicles and other technologies (like idle mitigating ePTO systems) also offer carbon reductions as well. Where idle mitigation systems are employed with diesel engines, reduced idling lowers particulates, or soot, generated with the combustion of diesel fuel. The Company's customers will benefit from the efforts to mitigate pollution, reduce greenhouse gas emissions, and lower its overall operating costs related to operating its internal fleet.

IV. FLEET SERVICES CAPITAL SPENDING PROJECTIONS

Q. Please describe the capital expenditures related to Fleet Services as shown on Exhibit A-12 (ASC-1), Schedule B-5.3.

A. Exhibit A-12 (ASC-1), Schedule B-5.3, provides gas Fleet Services capital spending, broken down into five capital spending categories: (i) Fleet Vehicle Capital Replacement

Plan; (ii) Fleet Vehicle Electrification; (iii) Fleet Business Partner Funded; and (iv) Fleet Tools - Garage. Exhibit A-12 (ASC-1), Schedule B-5.3, provides these capital expenditures with actuals for the 12 months ended December 31, 2022; projections for the 12 months ending December 31, 2023; 9 months ending September 30, 2024; 21 months ending September 30, 2024; and projections for the 12 months ending September 30, 2025, which is the test year in this case. For the historical year, 12 months ended December 31, 2022, the Company incurred gas Fleet Services capital expenditures in the amount of $8.806 million. The Company is projecting gas Fleet Services capital expenditures to be $9.892 million for the 12 months ending December 31, 2023; $3.870 million for the 9 months ending September 30, 2024; $13.762 million for the 21 months ending September 30, 2024; and $9.835 million in the projected test year ending September 30, 2025, as set forth in Exhibit A-12 (ASC-1), Schedule B-5.3, line 6, columns (b) through (f), respectively.

Q. Are there any contingency costs included in the Company's projected Electric Fleet Services capital expenditures?

A. No.

Q. What types of expenditures are included in Fleet Vehicle Capital Replacement Plan and Fleet Vehicle Electrification capital spending?

A. Fleet Vehicle Electrification expenditures include the offset cost of six (6) Chevrolet Silverado EV pickup trucks.

Q. What types of expenditures are included in Fleet Business Partner Funded?

A. Fleet Business Partner Funded expenditures include additional units purchased to support the Company's Advanced Methane Detection ("AMD") Systems, and one fully electric pick-up truck supporting PowerMIFleet education and outreach initiatives, both are described in detail later in my direct testimony.

Q. What types of expenditures are included in Fleet Tools?

A. Fleet tool purchases include the following: diagnostic equipment, tool sets, ergonomic tooling, and specialty equipment to properly and safely service and repair fleet vehicles, equipment, and trailers. This is described in detail later in my direct testimony.

Q. How did you determine the appropriate distribution of capital costs among the cost categories shown on Exhibit A-12 (ASC-1), Schedule B-5.3?

A. As required by the Commission's filing requirements, the Company itemized the capital investments for Transportation Equipment by using the following cost categories: contractor, labor, materials, business expenses, and other. The Company breaks out these cost categories by calculating a five-year historical average of each of the Commission's prescribed cost categories from years 2018 to 2022 as a percentage of total Transportation Equipment investment over that same period. The five-year historical average for each cost category was then applied to the Transportation Equipment Program's projected capital spending for the bridge year and the test year to arrive at estimates for each cost category (i.e., contractor, labor, materials, business expenses, and other). This method is consistent for the projected test year presented in Exhibit A-12 (ASC-1), Schedule B-5.3.

A. <u>Fleet Vehicle Capital Replacement Plan</u>

Q. What level of Fleet Vehicle Capital Replacement Plan spending is proposed in this case?

A. As shown in Exhibit A-12 (ASC-1), Schedule B-5.3, the Company is proposing to spend $9.506 million in the 2023 bridge year; $3.641 million for the 9 months ending

September 30, 2024; $13.147 million for the 21 months ending September 30, 2024; and $9.353 million in the 12 months ending September 30, 2025 test year on Fleet Vehicle Capital Replacement Plan spending.

Q. Does the Company anticipate variances within fleet spending?

A. While the Company attempts to be as precise as possible in the Fleet Replacement Plan, there is the potential for variances slightly above or below projected budget due to the nature of the fleet business that includes supply chain challenges. However, the Company continues to be good stewards of the fleet by working to meet all projected expenditures as close to targeted goals as possible.

Q. Please explain the Company's historical Fleet Vehicle Capital Replacement Plan expenditures for the 2022 historical year.

A. For the 2022 historical year, the Company is requesting recovery of $8.581 million of capital expenditures in Fleet Vehicle Capital Replacement for its gas fleet.

Q. Please explain the underspend of $785,000 for the historical year ending December 31, 2022?

A. As noted above, due to the potential for variances due to the nature of the fleet business, 10 units planned for delivered in 2022 pushed for delivery into 2023 due to delays resulting from delivery quality inspections, and part shortages.

Q. How did the Company determine its 2022 Fleet Vehicle Capital Replacement Plan spending level?

A. Replacement spending in 2022 will be primarily on units that were already ordered in 2021 for 2022 delivery. The specific units being replaced are shown in Exhibit A-38 (ASC-3).

Q. How did the Company determine its 2023 and 2024 Fleet Vehicle Capital Replacement Plan for the instant case, including the appropriate level of investment?

A. Units planned for purchase in 2023 and 2024 were determined using the methodology described earlier in my testimony. The Company is keeping Fleet Vehicle Capital Replacement Plan spending in 2023 and 2024 at historical spending levels, adjusted for inflation, based on what the Commission has previously approved for "lifecycle replacement spending." By remaining at this level for 2023 and 2024, the Company is demonstrating its commitment to keep costs affordable for customers. This set of vehicles was described earlier in my testimony, as shown in Exhibit A-38 (ASC-3).

Q How did the Company develop the list of vehicles that it plans to purchase in years 2024 and 2025 of this case?

A. The specific units that the Company plans to purchase in 2024 and 2025 are also shown in Exhibit A-38 (ASC-3). The Company produced an initial list of vehicles for replacement using the Blended Factor algorithm described earlier in my testimony, with a spreadsheet showing a Blended Factor percentage for each vehicle in the Company's fleet. This list was prioritized by the Blended Factor percentage to highlight vehicles that generate a positive (above 0.0%) percentage (the mathematical result of the Blended Factor calculation), which indicates that a vehicle has reached its expected life. Following the Blended Factor Analysis, as described previously in this testimony, the Replacement Plan filter included a review of market availability. By reviewing market availability, the Company can determine which replacement specifications can be expected for delivery in 2024 and 2025. Vehicles that are likely not available for delivery in 2024 and 2025 were not considered for replacement. To further refine the list of vehicles, standard crewing models were assessed. Though the Company will be continuing an analysis on right sizing, standard modeling helped guide the decision-making process.

Q. Was there additional analysis in determining the Fleet Vehicle Capital Replacement Plan for 2024 and 2025?

A. Yes. The list was further reviewed from a cost and utilization perspective. By assessing how often vehicles are used, the Company selected vehicles with a higher utilization rate when compared to similar specification. The Company further narrowed the initial Blended Factor-based list based on fleet stakeholders' input on condition. In this step, vehicles were assessed by age, mileage, and overall condition, and associated operating costs and mechanical improvements, such as a newly installed engine. Vehicles that received recent substantial investments (new engines, for example) are removed from the potential replacement list because their expected life is generally extended following such investments.

B. <u>Fleet Vehicle Electrification</u>

Q. In the projected test year, 12 months ending September 30, 2025, the Company is projecting an investment of $240,000. What is included in this amount?

A. As shown in Exhibit A-12 (ASC-1), Schedule B-5.3, the Company is proposing to spend $240,000 in the 12 months ending September 30, 2025 test year on Fleet Vehicle Electrification.

Q. What kind of purchases are included in Fleet Vehicle Electrification?

A. As shown in Exhibit A-38 (ASC-3), line 3, columns (i) and (j), Fleet Vehicle Electrification purchases include six (6) Chevrolet Silverado EV pick-up trucks.

Q. Why are the expenditures presented for Fleet electrification appropriate?

A. Fleet expenditures requested will be used to bridge the price gap difference between a standard ICE pickup truck and a plug-in EV pickup truck of similar function. The proposed spending would fund the purchase price difference between a standard ICE pickup truck and its EV equivalent. The purchase price difference between an ICE pick-up truck chassis and an EV pick-up truck chassis is approximately $40,000, totaling approximately $240,000 for six (6) Chevrolet Silverado EVs. The addition of these electric vehicles and will further the Company's efforts to reduce fuel and maintenance costs, as well as its overall carbon footprint.

Q. Why is the Company requesting only the purchase price difference between an ICE vehicle and an EV in this case?

A. Due to these vehicles being part of the replacement plan process, the funding to replace as an ICE chassis is already being requested as part of the capital replacement plan. Therefore, the Company is only requesting to offset the purchase price difference between a standard ICE chassis and the electrification cost of its replacement unit.

Q. How do these capital expenditures benefit the customers?

A. The expenditures in vehicle electrification will benefit the customer in several ways. Electric vehicles and plug-in hybrids are expected to lower the Company's overall fuel and maintenance costs as compared to ICE powered vehicles. The EVs proposed also offer significant potential reductions in greenhouse gas emissions, increasing the Company's carbon avoidance efforts, while providing service to our customers with less pollution at lower cost. Lastly, the units proposed for the Test Year will further the Company's learnings on EV best practices, planning, and deployment as it increases fleet electrification.

C. <u>Fleet Business Partner Funded</u>

Q. Please explain how Fleet Business Partner Funded expenditures work.

A. The Fleet Business Partner Funded program is one where "partners" are different organizations within Consumers Energy. When one business partner requires fleet vehicles or equipment, Fleet aligns with their needs, and goes out to find and obtain the most suitable vehicle/equipment to suit their needs. Because they become part of the Company's overall fleet, they fall within the purview of Fleet capital expenditures; thus, these proposed capital expenditures are found on Exhibit A-12, Schedule B-5.3 and Exhibit A-38 (ASC-3). In this case, the Company has included one EV pickup truck for the PowerMIFleet program, and three SUVs with AMD Systems for the Gas Strategy department within Gas Engineering and Supply.

Q. In Exhibit A-12 (ASC-1), Schedule B-5.3, page 1, line 4, column (c) for the 12 months ending December 31, 2023, the Company is projecting a Fleet Business Partner Funded investment of $152,000. What is included in this amount?

A. As shown in Exhibit A-38 (ASC-3), line 3, column (e), the Company is projecting investment of approximately $31,000 to fund one fully electric pick-up truck supporting PowerMIFleet education and outreach initiatives funded by that pilot as well as approximately $121,000 to support three SUVs supporting AMD Systems.

Q. Why is the Company including $31,000 for the Fleet Business Partner Funded electric pick-up truck?

A. The unit included in the Fleet Business Partner Funded capital expenditure is a common unit with the associated allocation split between gas and electric rate cases.

Q. How did you determine the needed level of spending for the Fleet Business Partner Funded electric pickup truck?

A. A low-cost electric truck configuration from a Michigan based manufacturer was selected that would have sufficient range for engaging at customer outreach events and discussions on electrification with fleets considering electrification.

Q. How do these capital expenditures benefit the customers?

A. Electric vehicles are a technology change for almost all fleet customers. Given this, being able to see and experience an electric work truck is important for customer education regarding infrastructure and charging requirements. Furthermore, by Consumers Energy modeling electric fleet adoption, customers have more confidence in the information being received from the PowerMIFleet pilot/program.

Q. Has the Commission previously approved spending for this Fleet Business Partner Funded equipment?

A. Yes. The Commission approved spending for PowerMIFleet administration and customer outreach in its December 17, 2020 Order in Case No. U-20697 for 2021.

Q. What concerns does Fleet Services have if the proposed capital expenditure amounts for expansion are not approved?

A. Presently, Consumers Energy has two smaller sedan electric vehicles (i.e. Chevy Bolts) that are utilized for customer events and educational outreach. With a limited light duty fleet, the Company loses the ability to expand its education internally as well as externally. The PowerMIDrive/PowerMIFleet team speaks to thousands of people and organizations per year, with an event or presentation on a near weekly basis. Being able to directly show people and organizations how EVs operate, charge, and can be programmed to charge off-peak, supports the Company's goal of attracting customers to the Company's PowerMIDrive and PowerMIFleet programs, which benefits all customers. Customers might be less likely to participate in PowerMIDrive and PowerMIFleet programs if the team did not demonstrate what it was promoting.

Q. In the 12 months ending December 31, 2023, the Company is projecting a Fleet Business Partner Funded investment of $121,000. What is included in this amount?

A. As shown in Exhibit A-38 (ASC-3), line 3, columns (e), the Company is projecting investment of $121,000 to purchase three total units, an SUV supporting AMD Systems.

Q. In the 12 months ending December 31, 2024, the Company is projecting a Fleet Business Partner Funded investment of $50,000. What is included in this amount?

A. As shown in Exhibit A-38 (ASC-3), line 3, columns (g), the Company is projecting investment of $50,000 to purchase one total unit, an SUV supporting AMD Systems.

Q. How did you determine the needed level of spending for the Fleet Business Partner Funded equipment in the 12 months ending December 31, 2023 and the 12 months ending December 31, 2024?

A. Company witness Kristine A. Pascarello's direct testimony in this case, starting on page 69, discussed two phases of implementation with enhanced leak surveying. Placing additional units in the system will support leak survey compliance and emission reductions. Fleet helped determine that the purchase of three SUVS, in lieu of redeploying an existing company asset, would be the most effective option to support this initiative. The requirements of these units and the extensive travel they will see on the road each day is not consistent with the way the rest of the Company's fleet operates. Providing vehicles that are capable of safely and efficiently transporting the driver and sensitive methane diagnostic and detection measuring equipment outweighed the risk of redeploying a less reliable unit.

Q. How do these capital expenditures benefit the customers?

A. As noted by Company witness Pascarello's direct testimony, starting on page 69, AMD will improve data and understanding of system risk, target higher risk areas for system improvements, and improve detection of methane. AMD will improve public safety and reliability by aiding in a strategic, and a data-driven approach to higher-risk leak identification and remediation. The use of AMD to increase the Company's situational awareness of system conditions to prioritize projects with greatest impact on the resolution of potential safety risks and/or methane emissions will benefit customers through cost effective improvements to system safety and emission performance. Additionally, with the increased sensitivity for methane detection, the Company will have improved capabilities to detect emissions, classify and repair them to improve public safety. It also supports the Company's goal of net zero methane emission by first time quantification and identification of large volume emission locations leading to prioritized remediation.

Q. What concerns does Fleet Services have if the proposed capital expenditure amounts for expansion are not approved?

A. The state-of-the-art methane detection equipment developed by Picarro requires a reliable, robust platform to function optimally. The vehicles selected to be used in conjunction with this equipment provide the appropriate space to operate the equipment but also allows for the room required to service and repair the mobile lab the units must carry to perform the task. If investments are not made to purchase the units supporting the AMD Systems, the Company will not be able to implement and take advantage of the AMD's benefits.

D. <u>Fleet Tools</u>

Q. What kind of purchases are included in Fleet Tools?

A. Fleet tool purchases include the following: diagnostic equipment, tool sets, ergonomic tooling, and specialty equipment required to properly service and repair fleet vehicles, equipment, and trailers.

Q. What level of expenditures is included in this rate case for Fleet Tools?

A As shown in Exhibit A-12 (ASC-1), Schedule B-5.3, the Company is proposing to spend $234,000 in the 2023 bridge year ending December 31, 2023; $179,000 for the 9 months ending September 30, 2024; $413,00 for the 21 months ending September 30, 2024; and $242,000 in the 12 months ending September 30, 2025 test year on Fleet Garage Tools. A further breakdown of this tooling type per year can found on Exhibit A-39 (ASC-4).

Q. Why are the expenditures presented for Fleet Tools appropriate?

A. To properly repair vehicles in a compliant, safe, and efficient manner, it is necessary to have the right tool for the task at hand. The tooling can be anything from diagnostic tooling, electronic service information, tool sets, or a new air conditioning recovery/recycle/recharge machine required to properly service R1234yf refrigerant. Diagnostic tooling is necessary for the repair of most vehicle systems such as the engine, transmission, air bag, lighting, and anti-lock brakes. This tooling requires updates to maintain access to new vehicle models. Electronic service information is required to diagnose vehicle concerns and to follow the manufacturer's recommended repair procedures. Additional tooling such as hydraulic torque wrenches are critical in ensuring that high torque fasteners requiring very high torque applications are properly set and adjusted to manufacturer torque specifications to ensure safe repairs and inspections. Maintenance equipment, such as an R1234yf air conditioning machine, are required to meet Environmental Protection Agency standards for safely recovering and recharging air conditioning systems on newer model year vehicles.

Q. What benefits does this level of Fleet Tools spending provide to customers?

A. Across the state, the Company has 36 locations where Fleet mechanics are permanently stationed to perform their daily work. The Company also has remote sites, training facilities, and jobsite reporting locations where repairs to vehicles and equipment are also performed. The projected Fleet Tools for 2024 spending is approximately $484,000 for the entire Company, or approximately $13,444 for each of the 36 locations where mechanics are stationed. The gas allocation of this total is approximately $238,000. Each year, the Company replaces, and updates outdated or unrepairable shop equipment such as floor jacks, diagnostic equipment, tire machines, and welders. The benefit to our customers of having tools in good order is less downtime for vehicles and reduced maintenance expenses because the Company is not solely reliant on outside repair shops to complete work needed to keep vehicles active. Most repair and maintenance items are performed by the Company's in-house mechanics; therefore, it is imperative that the Company maintain a complete and updated inventory of tools to complete the work required.

Q. Does this conclude your direct testimony in this proceeding?

A. Yes.

S T A T E O F M I C H I G A N

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the application of	)	
CONSUMERS ENERGY COMPANY	)	
for authority to increase its rates for the	)	Case No. U-21490
distribution of natural gas and for other relief.	)	
	)	

DIRECT TESTIMONY

OF

AMY M. CONRAD

ON BEHALF OF

CONSUMERS ENERGY COMPANY

December 2023

Q. Please state your name and business address.

A. My name is Amy M. Conrad, and my business address is One Energy Plaza, Jackson, Michigan 49201.

Q. In what capacity are you employed?

A. I am employed as the Manager of Compensation Operations for Consumers Energy Company ("Consumers Energy" or the "Company").

Q. What is your educational background?

A. I graduated from Central Michigan University in 1999 with a Bachelor of Science Degree in Business Administration with a major in Accounting. In addition, I am designated as a Certified Compensation Professional and Certified Executive Compensation Professional by WorldatWork and a Certified Public Accountant by the Michigan Association of Certified Public Accountants. WorldatWork is an international professional organization focused on human resources issues, including compensation, benefits, work life, and integrated total rewards to attract, motivate, and retain a talented workforce.

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

A. In February 2002, I joined Consumers Energy as a Financial Reporting and Technical Accounting Analyst. My duties included accounting and reporting of equity-based compensation, technical accounting standard research, and preparation of quarterly and annual Securities and Exchange Commission ("SEC") filings. After eight years of progressing responsibilities in this role, I transferred to the position of Principal Human Resources Consultant. In 2013, I was promoted to the position of Director of Compensation. In this role I had the responsibility for administering Consumers Energy's compensation function and partnering with Labor Relations on union compensation matters. This included developing compensation programs designed to attract and retain a qualified workforce for the Company. My duties included gathering of comparable wage and salary data in order to determine how Consumers Energy's pay level compares to the labor market and developing compensation programs that are competitive and deliver pay to employees that is fair and equitable and that motivates employees to perform at their full potential.

My responsibilities also consisted of assisting with preparation of materials for the Compensation Committees of the Consumers Energy and CMS Energy Boards of Directors, including the Compensation Discussion & Analysis section of the annual proxy statement for the named executive officers.

In May 2018, I took on the role of Director of Executive and Incentive Compensation. My responsibilities consisted of assisting with preparation of materials for the Compensation Committees of the Consumers Energy and CMS Energy Boards of Directors, including the Compensation Discussion & Analysis section of the annual proxy statement for the named executive officers. My responsibilities also included administering the incentive plans for CMS Energy, including Consumers Energy.

In August 2023, I took on the role of Manager of Compensation Operations. My Manager of Compensation Operations responsibilities consist of the implementation of new and revised non-officer compensation programs, policies and procedures for non-officers to align with the Company's goals and competitive practices. This position is also responsible for ensuring that compensation programs are consistently administered in compliance with internal policies and government regulations. The Manager, Compensation Operations role focuses primarily on the coordination and implementation of the non-officer merit, incentive, stock administration, survey participation and ensuring accuracy of data for non-officer programs.

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

A. Yes, I have testified in Case Nos. U-17087, U-17197, U-17643, U-17735, U-17882, U-17990, U-18124, U-18322, U-18424, U-20134, U-20322, U-20650, U-20697, U-21148, U-21224, U-21308, and U-21389.

Q. What is the purpose of your direct testimony?

A. The purpose of my direct testimony is to provide support for Consumers Energy's request for rate recovery for costs of its annual Employee Incentive Compensation Plan ("EICP") at target levels. The EICP is a form of short-term incentive. Short-term incentive pay is designed to focus and reward performance over periods of approximately one year or less.

First, I will discuss Consumers Energy's overall compensation philosophy. In this section of my direct testimony, I will discuss the importance of paying employees a competitive level of compensation and the reasonableness of the overall compensation levels that the Company is requesting in this case. In addition, I will discuss (i) the fact that EICP compensation is part of an employee's overall market-based compensation and not in addition to it, and (ii) why Consumers Energy has included EICP at target levels as part of overall market-based compensation.

Second, I will discuss the EICP incentives and provide support for the Company's request for rate recovery in this case related to Consumers Energy's non-officer and officer operational goal portion of EICP. In my direct testimony, I will discuss the design of the EICP.

Third, I will discuss customer-related benefits that result from use of the incentive plans and how customers are best served when Consumers Energy can attract, retain, and motivate a talented workforce with compensation packages that are competitive and fair. Elimination of the EICP would result in Consumers Energy's employee compensation being below market and would hinder the Company's ability to attract and retain a qualified workforce that best serves customers.

Q. Please summarize your conclusions.

A. My conclusions include the following: (i) use of incentive compensation by utility companies is an accepted, common, and reasonable practice; (ii) Consumers Energy's decision to make a portion of compensation at-risk and subject to incentives is reasonable; (iii) the amount of overall compensation included by Consumers Energy in this case is reasonable and is reasonably necessary to attracting and retaining a talented workforce; (iv) incentive compensation is part of the reasonable level of market-based compensation and not in addition to it; (v) recovering costs of Consumers Energy's EICP employee incentive plans will not result in excess rates; (vi) Consumers Energy's EICP performance goals and thresholds provide customer-related benefits; and (vii) the EICP goals provide customer-related benefits at no incremental cost to customers above those included in market-based compensation.

Q. How is the remainder of your direct testimony organized?

A. The remainder of my direct testimony is organized as follows:

I. OVERVIEW

II. EMPLOYEE COMPENSATION PHILOSOPHY

III. INCENTIVE COMPENSATION PLANS

A. Description of Incentive Plans

B. Assessment of Customer Benefits of the Incentive Compensation Plans

IV. CONCLUSION

Q. Are you sponsoring any exhibits?

A. Yes. I am sponsoring the following exhibits:

Exhibit A-40 (AMC-1)	EICP Performance Measures;
Exhibit A-41 (AMC-2)	Target Pay Level Market Analysis; and
Exhibit A-42 (AMC-3)	Summary of Actual and Projected – Annual Incentive O&M Expenses.

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

A. Yes.

I. <u>OVERVIEW</u>

Q. What is the Company's compensation philosophy for non-officer employees?

A. Consumers Energy's compensation philosophy for its non-officer, non-union employees is to provide market-based compensation tied to performance. A competitive compensation policy benefits customers by attracting and retaining employees with the necessary skills and experience to deliver world-class customer service and minimize the risks and costs of employee turnover. Incentive pay is a component of providing market-based compensation.

Q. What is the Company's compensation philosophy for officer employees?

A. Consumers Energy's compensation philosophy for its officers is centered around four principles:

1. Align with increasing shareholder and customer value;
2. Enable the Company to compete for and secure top executive talent;
3. Reward measurable results; and
4. Be fair and competitive.

Incentive pay is a reasonable component of delivering this philosophy.

Q. How does Consumers Energy structure non-officer compensation for its salaried employees?

A. Consumers Energy first determines what a competitive level of pay is for salaried nonofficer employees. It does so by using various market surveys. The practice of using multiple surveys is common practice. It allows for a broader participant pool and confirmation that the survey data is representative of market competitive wages and trends. Consumers Energy then structures the compensation by allocating this market-based wage between base salary and incentive compensation. The incentive compensation is part of the overall market-based competitive level and it is not in addition to it. Total compensation is targeted at approximately the market median (50^{th} percentile).

Q. How does Consumers Energy structure officer compensation?

A. Officer compensation levels are determined by the Compensation Committees of the Boards of Directors of Consumers Energy and CMS Energy. The Company creates a compensation package for officers that delivers base salary, annual incentive compensation, and long-term incentive compensation targeted at the median or

50th percentile of the competitive market. In determining individual officer compensation levels, the Compensation Committees are advised by an independent third-party consultant and take into consideration market research, experience levels, and individual contributions.

Q. In this proceeding, is the Company requesting rate recovery of all Operating and Maintenance ("O&M") gas expenses related to short-term incentive compensation plans?

A. No. The Company utilizes both financial and non-financial (operational) goals in its short-term incentive compensation plan. While the Company believes that both financial and non-financial (operating) short-term incentive compensation expenses are reasonable, the Company in this case is excluding the costs of short-term incentive compensation linked to financial goals ($4.9 million). Included in that $4.9 million amount is the removal of the affordability (O&M savings) operational measure. The Company determined that the affordability measure, although included among the Company's operational goals for purposes of the EICP, is financial in nature; therefore, the Company removed the dollars attributable to that measure from the rate request in this case along with the dollars attributable to the other financial measures.

Q. Is Consumers Energy requesting recovery of all officer incentive pay linked to non-financial (operational) goals in this rate case proceeding?

A. Yes. The Company in this case is seeking recovery for the incentive costs associated with the operational goals portion for all officers. This is a result of the addition of 30% of officer pay directly linked to operational measures. In prior cases, the Company excluded the top five officers, but sought recovery of all measures which were financial with a modifier to the non-officer non-financial goals.

Q. Is Consumers Energy requesting recovery of long-term incentive pay in this rate case proceeding?

A. No. The Company is not seeking recovery for the costs of long-term incentive compensation (sometimes referred to as restricted stock plans) in its rate recovery request in this case.

Q. Why is the Company requesting rate recovery of short-term incentive compensation operational goal expenses?

A. Consumers Energy uses market data to determine an overall competitive level of compensation. Competitive compensation includes base salary and short-term incentive compensation for officers and non-officers. Consumers Energy's overall compensation levels are reasonable compared to the market. Compensation levels without these incentive payments would be below market competitive levels. Paying non-competitive levels of compensation would result in a less qualified workforce that would not best serve customers. A November 2021, Wall Street Journal entry stated:

> Many senior executives are struggling with an urgent talent crisis: The Great Resignation. The COVID-19 pandemic has induced waves of people to quit their jobs, seemingly in search of more meaning, more money, and more flexibility, among other wish-list items. The labor and skills shortage is now so severe that CEOs rank it as the No. 1 external issue they expect to influence or disrupt their business strategy within the next 12 months.

In order to hire and retain qualified personnel, it is necessary to either pay a competitive incentive or increase base salaries to make up for the missing incentive compensation component. Use of annual incentive mechanisms is a recognized management technique for companies, including utility companies. As I discuss later in my direct testimony, incentive pay is the number one compensation design element used to influence short- to mid-term performance results. Incentive mechanisms help communicate priorities, engage the employees in operating and financial success, reward valued skills and behaviors, and create business understanding for employees. Consumers Energy's incentive programs are structured in a way that is designed to help keep non-officers and officers focused on operational performance areas such as continuous improvement, safety, cost, reliability, and delivery. The incentive compensation program encourages employees to deliver outcomes which result in meeting customers' expectations. The EICP incentive compensation costs are reasonable costs of doing business and, therefore, should be recovered in rates.

Q. Who is eligible for the EICP incentives?

A. All non-union employees are eligible for EICP incentives, with the exception of employees who are rated as "under-contributing" or "needs improvement" on their annual performance appraisals. These under-performing employees are ineligible to receive an EICP incentive. Both non-officers and officers participate in an annual EICP incentive.

Q. How are the EICP incentives structured?

A. The EICP incentives are structured by non-officer and officer EICP. The 2022 non-officer EICP equally weights the operational measures with the financial measures:

- Half (50.0%) of employees' incentive will be based on the achievement of operational performance measures. (For 2022, there are six operational measures.); and
- Half (50.0%) of employees' incentive will be based on the achievement of one financial measure, Earnings Per Share ("EPS"). Consumers Energy is a vital part of the Michigan economy, and it is important that the utility remains financially strong so that it can provide the utility service that customers expect

> and deserve; however, Consumers Energy is not seeking recovery of the financial portion of the EICP.

In past cases, the goals were the same for the officer EICP, but the weightings were different. All (100.0%) of officers' incentive was based on the achievement of two financial measures, EPS and operating cash flow, with a plus or minus modifier to the operational goals.

Starting in 2022, the officer operational goal modifier was removed and replaced with the same operational measures as non-officers with a weighting of 30%. Also beginning in 2022, operating cash flow has been removed.

II. EMPLOYEE COMPENSATION PHILOSOPHY

Q. What is Consumer Energy's philosophy about the overall level of compensation?

A. The Company's management believes Consumers Energy should pay a fair and reasonable salary, comparable to the market that is equitable to employees, consistent with Company values and strategies, and that supports the highest level of customer service at a reasonable cost.

Q. What are the components of Consumers Energy's compensation for non-officer employees?

A. There are two parts of overall compensation for non-officer employees of Consumers Energy. The first part is base pay. The second part for salaried employees is annual incentive compensation.

Q. What are the components of Consumers Energy's compensation for officers?

A. There are three parts of overall compensation for officers of Consumers Energy. The first two parts are cash compensation through base pay and annual incentive compensation. The third part is equity-based long-term incentive. As I mentioned earlier in my direct testimony, the Company is not seeking recovery for the costs of long-term incentive compensation in its rate recovery request in this case.

Q. Why does the Company make a portion of compensation subject to incentives?

A. A wide body of research supports the view that incentive pay (a variable pay component) works. One researcher states, "theory and research show that incentive pay can substantially increase individual and organizational performance and can represent a powerful tool for establishing a competitive advantage within an industry." (Dow Scott, *Incentive Pay: Creating a Competitive Advantage* – WorldatWork Press, 2007). There are many more cases of incentive plans as an effective motivational tool. Group incentive plans can contribute to organizational collaboration and achievement of company goals which lead to benefits for customers. A May 15, 2018, Forbes article entitled "The Key to an Effective Incentive Plan" (Bill Fotsch and John Case) continues to support this theory indicating:

> Incentive plans, by definition, are supposed to affect people's behavior on the job, day in and day out. They incent people to work harder and smarter, to go the extra mile, to collaborate with their coworkers, to come up with new ideas to improve some aspect of the business.

People don't work for money alone, but they do respond to incentives.

When properly selected and implemented, incentives motivate employees, focus employees on a company's goals, and increase both individual work performance and team performance. When goals are challenging yet achievable, employees are motivated to increase productivity and performance to achieve the goal. In addition, incentives increase a company's ability to attract, hire, and retain qualified and motivated individuals. A study by the International Society of Performance Improvement showed that incentive pay programs increase performance by an average of 22.0%. (International Society of Performance Improvement, "Incentives Motivation and Workplace Performance Research and Best Practices," Spring 2002). As stated by the Society of Human Resource Management:

> Research has demonstrated that some human resource programs and initiatives produce a significant impact on performance in organizations (as measured by factors such as quality, productivity, speed, customer satisfaction and unwanted turnover). The two initiatives that consistently showed statistically significant positive results were linking pay to performance and using variable pay. Research has established the potential of variable pay to produce the desired business results. [Robert Greene, "Variable Pay: How to Manage it Effectively, Society of Human Resource Management," April 2003.]

Consumers Energy has adopted incentives that are designed to emphasize operational performance criteria in areas that are critical to the Company's utility business and customers. Focusing employees on these goals provides both qualitative and quantitative benefits for Consumers Energy's utility customers. High-level qualitative customers benefits are listed later in my testimony. Company witness R. Michael Stuart's testimony illustrates the quantitative benefits to customers.

Q. Are the overall compensation levels for employees subject to the non-officer EICP reasonable?

A. Yes. Overall compensation levels for employees subject to the non-officer EICP and management's decision of how to allocate the overall compensation between base salary and EICP are reasonable. As stated later in my testimony it is common practice for companies to have a variable pay (i.e., EICP) component of total competitive compensation levels.

Q. How does Consumers Energy determine what level of overall compensation for non-officers is reasonable?

A. First, Consumers Energy's management targets overall compensation to the market median. Second, Consumers Energy's management actively reviews compensation levels so that employees are neither overpaid nor underpaid relative to the market. Third, the Company uses a rigorous survey process which uses valid and reliable data from multiple third-party sources to determine median levels of compensation. The fact that a portion of the compensation is in the form of an incentive payment does not mean that employees are paid in excess of market rates when they receive their incentive payment. To the contrary, removing the incentive from employees' total compensation package or failing to meet incentive performance goals, would render their compensation below-market.

Q. Would it be reasonable for Consumers Energy to pay employees below market level on an ongoing basis?

A. No.

Q. Why would it be unreasonable for Consumers Energy to pay below market level?

A. Consumers Energy has a responsibility to customers to employ a competent workforce that is ready, willing, and best able to provide service for our customers. Paying competitive wages and salaries is necessary to fulfill that commitment. It would not be reasonable or fair to the Company, its employees, or customers for the MPSC to set rates at a level that did not include reasonable levels of overall market-based compensation.

The level of service that customers deserve requires a qualified, experienced, and motivated workforce. The Company can attract, retain, and motivate talented employees when its overall compensation is competitive with market levels. A decision to compensate employees below market levels would detract from the Company's ability to assemble the committed and customer-focused workforce that customers deserve. Over time, this would be detrimental to customers, as well as being unreasonable to the Company's diligent, hardworking employees. Compensating employees below market levels will eventually result in their leaving for jobs that are paying at market levels. Also given the difficult labor market for candidates in 2022, offering below market-level compensation could harm the Company's ability to fill vacancies. Over time, the workforce would tend to be less qualified, less experienced, less productive, and less capable of serving customers (as the most capable would, in general, tend to go to employers paying at competitive levels). This, in turn, could lead to less efficiency and could result in a need to hire more employees to produce the same service to customers, thus increasing costs to our customers.

Q. How does the Company determine the level of overall compensation for salaried non-officer employees?

A. For salaried non-officer employees, the Company uses salary survey data from utility and energy companies. Using this survey data, a benchmarking analysis of total compensation (base pay and incentive pay) is made between the Company's jobs and comparable survey jobs. Benchmarking analysis is a comparison of jobs commonly found in the labor marketplace and/or a job that is highly relevant/populated within a company. This comparison indicates where the Company's pay stands relative to the market. The Company's goal is to target overall pay levels within plus or minus 5.0% of the market median for non-officers. While pay for individuals inevitably varies from the survey market levels due to differences in experience levels, education, job performance, longevity, position responsibilities, etc., the survey data indicate that the Company's overall non-officer compensation levels, assuming the EICP payment at the target level, are on average within target pay level of plus or minus 5.0% of market median. Exhibit A-41 (AMC-2) provides a summary of average exempt and non-exempt pay for Company benchmark jobs compared to market using 2023 data for 2023 pay structure purposes.

Paying compensation that approximates the market median is particularly important given that Consumers Energy will continue to experience significant attrition (current employees eligible for retirement is 17% of the workforce) and have a need over the next few years to hire engineers and other personnel to staff various projects and serve customers. Competitive pay is necessary to retain the talent needed to deliver on the Company's Integrated Resource Plan ("IRP"). In competing for engineers, as well as other personnel that are skilled, high-performing customer-focused candidates, it will be important to have a reputation for paying a competitive level of overall compensation. Excluding the incentive target amounts would result in the Company's pay levels being approximately 5.0% to 10.0% below market level.

Q. How do you know the market data that the Company is using are appropriate and are not inflating salary levels?

A. The Company uses several third-party survey sources to compare to the non-officer salaried workforce. The Company participates in and uses an industry survey performed by Willis Towers Watson, Aon, and Mercer, both well-respected, independent third-party compensation experts. These surveys are conducted by surveying companies which report data on an anonymous basis. When using the survey data, the Company looks at the median base pay and incentive (total compensation) reported for highly populated jobs for which there is a comparable job match. In this way, the Company is matching the relevant market, not trying to lead the market, and thus not inflating its overall compensation above prevailing market levels. By using multiple independent survey sources, the Company can determine if any one source is varying significantly from another.

Q. Can you give an example of the relationship between the Company's pay levels and the market's pay levels?

A. See Exhibit A-41 (AMC-2) for a summary of average exempt and non-exempt pay for Company benchmark jobs.

Q. Are incentive plans common in the utility industry?

A. Yes, incentive plans are quite common. Annual incentive programs are a critical and highly integral part of competitive compensation packages for many organizations. Research from Willis Towers Watson's 2012 Survey Report indicates that approximately 80.0% of companies offer annual incentive (variable pay) programs. That number is slightly higher at 81.2% for those companies within the utility industry sector. The survey data supports the conclusions that including incentive pay as part of a competitive pay package is a standard industry practice and is required to attract and retain good employees.

Research from Mercer's 2014/2015 U.S. Compensation Planning Survey Report indicates that approximately 83.0% of companies offer annual incentive (variable pay) programs. For companies within the utility industry sector, the survey indicated that 98.0% of executives, 99.0% of management, 94.0% of non-sales professionals, and 86.0% of clerical and technicians were eligible for an annual incentive.

A 2012 Mercer study of more than 1,200 organizations reveals that actual company spending on variable pay for salaried exempt employees, as a percentage of pay, is 12.0%

and salaried/hourly non-exempt employees, as a percentage of pay, is 6.0% to 7.0% for energy companies. A 2009 Hewitt Associates study of more than 1,100 organizations further reports that companies were budgeting variable pay for salaried exempt employees at 11.8%, and 5.5% to 6.1% for salaried/hourly non-exempt employees, for 2010. Ken Abosch, leader of Hewitt's North American Broad-Based Compensation Consulting business, added:

> Over the past decade, we've seen companies steadily shift from a fixed pay model to one that emphasizes true performance-based awards, and we expect this trend will continue.

Consumers Energy's practice of making a portion of overall employee compensation subject to incentives is consistent with best practices for compensation.

Q. What has been the trend in variable or incentive pay?

A. A 2016 study by Aon Hewitt indicated a 72% growth in variable pay spend over the past 20 years. Variable pay grew from 4.1% of base salaries in 1996 to 12.9% of base salaries in 2015. Business incentive plans are the most prevalent with 77% of companies using this type of variable pay award in 2015 up from 55% in 1996. Business incentive plans refer to plans that are based on Company financial and/or operational goals. According to a 2021 study published by WorldatWork and Compensation Advisory Partners, the vast majority of companies (99%) have short-term incentive programs. ("Incentive Pay Practices: Publicly Traded Companies," July 2021, WorldatWork and Compensation Advisory Partners). Moreover, a 2020 study by Willis Towers Watson on Salary Increases shows that 89% of Energy companies utilized short-term incentive (EICP) compensation programs.

Q. Why is the use of incentive pay such a widespread practice?

A. Incentive pay is the number one design used to influence short- to mid-term business or performance results. Coupled with clear strategy, solid leadership, and good, safe working conditions, variable pay incentive designs:

- Increase employees' understanding of what is important to the Company;
- Increase employees' identification with the Company's success and the factors by which it is measured;
- Reward valued skills and behaviors; and
- Enhance employee engagement by educating them on how and why their contributions will benefit them, the Company, and our customers.

Dividing overall compensation between base salary and incentive compensation is an approach that is common and effective in business today.

Q. How many employees does the Company have that will be eligible for the non-officer EICP payout?

A. Consumers Energy has approximately 4,800 employees (total utility) who are eligible to receive an incentive if, and when, the requirements for a payout are met. The risk of no payout is the same for all these eligible employees. Either every eligible employee receives a payout, or no one receives any incentive compensation.

Q. How did the Company determine the level of compensation that would be provided as incentive compensation for these eligible employees?

A. For the historical test year, the EICP target level for each pay grade was established by reviewing third-party market data on the mix of base salary and at-risk variable pay (EICP), historical rate case relief and amounts that will assist in motivating performance that will result in benefits to our customers. The EICP compensation is part of the overall market-based competitive level of compensation, not in addition to it. Beginning in 2024, the EICP target level will be based on career stream and job level established by reviewing third-party market data on the mix of base salary and at-risk variable pay.

Q. Explain if the Company reduced base pay when it started to pay incentive awards in order to obtain market-based pay based on the combination of the two components of pay.

A. The Company has always had a broad-based incentive compensation plan in place for salary grades 19 and above (typically management level). In 2003, an EICP for employees in salary grades 18 and below (typically individual contributors in technical, professional or support roles) was initiated. Base pay levels were not reduced for these employees at the time the plan was implemented. This was due to the fact that at the time the plan was implemented, total compensation, which is base salary and annual incentive, was slightly below the 50^{th} percentile (median) point of survey results. The Company targets pay levels of plus or minus 5.0% of market median. The Company's pay level, including the additional incentive, continues to be within this range.

Q. Is there an alternative to providing incentive pay for salaried employees?

A. The alternative would be to increase the base compensation to a level that approximates the overall competitive market level of compensation. Absent the higher base pay, Consumers Energy's compensation offering would not be competitive with the labor market. For example, if the base target were $50,000 for a hypothetical job and market-based average pay was $50,000 plus a $2,000 incentive award, then the Company would need to offer $52,000 to match the market's current pay. So, the alternative to having an incentive component of overall compensation would be to raise base pay to the market's overall compensation. Eliminating incentive pay would result in the same compensation costs, but employees would lose focus on continuous improvement, safety, quality, cost, reliability, and delivery to the customer. Increasing base pay would also result in a higher level of fixed costs tied to base pay, such as certain pension and defined contribution benefit plans, life insurance, disability insurance, and other salary-based employee benefits.

The Company's overall compensation needs to be comparable to the market for salaried employees regardless of whether it is composed of only base pay or composed of base pay plus the target incentive award amount. The Company has maintained overall compensation at competitive levels through base pay plus the target incentive award amount.

Q. Would elimination of incentive pay be in the best interests of customers?

A. No. With incentive compensation, the employees and the Company must re-earn the at-risk compensation each year. If high levels of performance are not met each year, incentive pay can be reduced or eliminated. The elimination of variable "at risk" pay would create a situation where all compensation is guaranteed and would remove an important incentive to improve service. This result would be counter to customer interests. The elimination of variable "at risk" pay would create a situation where compensation would be below market competitive levels. Competitive pay is needed to attract and retain the high-quality talent required to deliver exceptional service to our customers. It would be difficult to achieve our company purpose of world-class performance delivering hometown service without the right talent. The knowledge, skills, and abilities of our employees are key determinants in the quality and timeliness of service that customers receive. Our ability to deliver what customers expect such as reliable and safe energy delivery, on-time completion of service orders, and energy savings depends upon having the right talent in the right job at the right time. Having incentive compensation that is structured around goals that provide benefits to customers is in the best interest of the customer.

Q. How does the Company determine the level of overall compensation for officers?

A. A utility must maintain a competitive total compensation package to attract and retain executive talent. As discussed above, Consumers Energy creates a compensation package for officers that delivers base salary, annual incentives, and long-term incentives (excluded from the Company's request in this rate case) targeted at the 50th percentile of the market, as defined by a Compensation Peer Group approved by the Compensation Committees of the Boards of Directors. The Compensation Peer Group consists of energy companies comparable in business focus and size to CMS Energy with which the Company might compete for executive talent. The Compensation Peer Group currently includes 18 companies.

Q. How do you know the market data that you are using for officer compensation are appropriate and are not inflating salary levels?

A. Annually, the Compensation Committees engage an independent third-party consultant to provide advice and information regarding compensation practices of a Compensation Peer Group, which it develops based on criteria discussed below, as well as taking into account additional information from published surveys of compensation in the public utility sector and general industry. During the Compensation Committee's review of officers' compensation levels, consideration is given to the advice and information received from the independent compensation consultant; however, the Compensation Committee is ultimately responsible for determining the form and amount of the compensation programs.

Where available by position, Compensation Peer Group data serves as the primary reference point for pay comparisons of utility specific roles, and broader survey data and published proxy data are also provided by the compensation consultant as a point of reference for utility-specific roles and comparisons of general industry roles. Where available by position, the independent executive compensation consultant of the Compensation Committee, gathers compensation data from Willis Towers Watson's Energy Services Executive Database (over 50 investor-owned utilities) and Willis Towers Watson's General Industry Executive Database (approximately 500 participating companies), which it regresses based on CMS Energy's revenues to provide additional market context to the Compensation Peer Group. In selecting members of the Compensation Peer Group, financial and operational characteristics are considered. The criteria for selection of the Compensation Peer Group included comparable revenue, relevant utility industry group, similar business mix (revenue mix between regulated and non-regulated operations), and availability of compensation and financial performance data.

The survey data indicate that the Company's overall officer compensation levels, assuming the EICP and restricted stock payment at the target market-based level, are reasonable.

In addition, annually, proxy-advisor service companies Glass Lewis & Co. and Institutional Shareholders Services assist institutional investors in their advisory vote on the reasonableness of compensation pay and practices of the proxy-named executive officers by providing a vote recommendation. The incentive pay practices for the proxy-named executive officers are the same as for the remaining officer group. In 2022, both proxy advisory service firms recommended a vote "for" the proxy-named executive officer compensation pay and practices. Also, shareholders voted 97% in favor to approve executive compensation as described in the 2023 Proxy Statement which is above the S&P 500 average of 89%.

Q. Does the independent consultant provide other services for CMS Energy or Consumers Energy that could result in a conflict of interest?

A. No. The independent consultant is required to obtain approval of the Compensation Committee of the Boards of Directors before undertaking any activity on behalf of the management of CMS Energy or Consumers Energy. During the time the consultant has been engaged as the compensation consultant for the Boards of Directors, it has not performed any services on behalf of the management of CMS Energy or Consumers Energy. The independent consultant is hired by and serves the Compensation Committee; it is not hired by or providing services to CMS Energy or Consumers Energy.

Q. Are surveys the only determining measure used in setting officer compensation levels?

A. No. Additionally, the Compensation Committee considers experience levels and individual contributions of the respective officers.

Q. Are incentive plans for officers common in the utility industry or in other industries?

A. Yes, incentive plans are prevalent. Research from Mercer LLC, U.S. Compensation Planning 2014/2015 survey indicates that approximately 96.0% of companies, and 98.0% of energy companies, offer annual incentive (variable pay) programs for officers. The survey data support the conclusions that including incentive pay as part of a competitive pay package is a standard practice and is required to attract and retain qualified officers.

III. INCENTIVE COMPENSATION PLANS

A. Description of Incentive Plans

Q. Please describe the EICP that is in place for 2022.

A. The EICP for 2022 is based on achieving performance goals related to critical areas of the Company's operations. The goals focus on continuous improvement measures and maintaining financial health to deliver value benefits to our customers (not seeking recovery of financial goals in this case). The Company's EICP goals seek to encourage employees to provide reliable energy, customer value, and responsive service to our customers, and to do so safely. Each year, the Company establishes utility-specific performance criteria which focus on continuous improvement goals and breakthrough goals. For 2022, there were six specific operational performance measures and one measure related to being financially health. The EICP Operational Performance Measures are summarized on Exhibit A-40 (AMC-1). The 2022 officers and non-officer goals and weighting are shown on page 1 and 2022 operational goal targets on page 2.

Q. Please describe Exhibit A-40 (AMC-1).

A. Exhibit A-40 (AMC-1) identifies the operational performance areas that the EICP focuses on and identifies the specific measures that have been adopted for each of these areas. For the 2022 historical year, 50.0% of the non-officer incentive compensation and 30% of officer incentive compensation was based on operational performance. For purposes of this rate case the Affordability (O&M savings from Waste Elimination) measure associated costs has been removed from the rate request as the Company has determined that it is financial in nature.

Q. Is the structure of the EICP goals for 2023 similar to 2022?

A. The specific performance measures and targets for 2023 are, as in prior years, a combination of measures related to operational performance and financial performance. As indicated above, the Company is not seeking recovery of the financial performance measures in the case. For non-officers, the operational performance and financial health goals will be weighted equally (50% operational and 50% financial). For officers, the operational performance and financial performance measures are weighted 30% operational and 70% financial. The officer operational goals are the same as the non-officer operational goals.

Q. Is the eligibility for the EICP plan for 2023 and the projected test year similar to 2022?

A. In third quarter 2023, Consumers is implementing an updated job architecture. Job architecture encompasses job levels, job titling, pay grades, career paths, spans of control, the criteria for career movement, and equitable compensation programs based on job value. Job architecture serves as the foundation that will help us to attract and retain the high-quality talent required to deliver service to our customers. As a part of implementing the new job architecture, compensation programs such as the EICP will be reviewed. This review will result in the EICP target for non-officers to shift from one based on pay grade to one based on career stream (management, professional, technical or support) and level (i.e. entry, career, senior, supervisor, manager, director, ect.), which may result in changes to eligibility. No specific EICP changes are known for the test year as of the date of this filing. With this change, the EICP continues to provide a link to the company strategy and what is important to delivering safe and reliable energy to our customers.

Q. Will the non-officer performance measures continue to incorporate measures that provide benefits to Consumers Energy's customers?

A. Yes. Performance measures will continue the focus on world class performance delivering hometown service and will continue to have as their foundation continuous improvement and breakthrough measures. While the number and precise phrasing of operational goals may vary from 2022 historical test year, areas of focus will continue to include safety, reliability, cost, delivery, and customer care.

Q. Will the officer performance measures continue to incorporate measures that provide benefits to Consumers Energy's customers?

A. Yes. Operational and financial performance measures will continue the focus on world class performance delivering hometown service and will continue to have as their foundation continuous improvement and breakthrough measures. The operational measures will hold a weighting of 30%, meaning 30% of the officer incentive compensation is based on operational performance (same goals as non-officers) and the remaining 70% is based on financial performance. As noted above, the Company is not seeking recovery of the financial performance measure in this case.

Q. Please discuss the strategy and process for developing the EICP goals.

A. Company witness Stuart provides a discussion of the strategy and process for developing the EICP goals.

Q. Why has the Company's management chosen to design the EICP with broad goals and objectives on a Company-wide basis rather than individual goals and objectives for individual employees?

A. It is necessary and appropriate for a large organization, such as Consumers Energy, to establish broad goals and objectives that are communicated to all employees as matters that are important to the success of the organization. Some employees will be in a better position to influence whether particular goals and objectives are met, but having every employee linked to a set of common customer-focused objectives is an effective method for emphasizing the importance of customer value and service. Having common goals and objectives (i) provides clear communication of Company goals, (ii) encourages employees to support each other and work together for common goals, and (iii) provides a scorecard with a focus on corporate-wide goals that benefit customers.

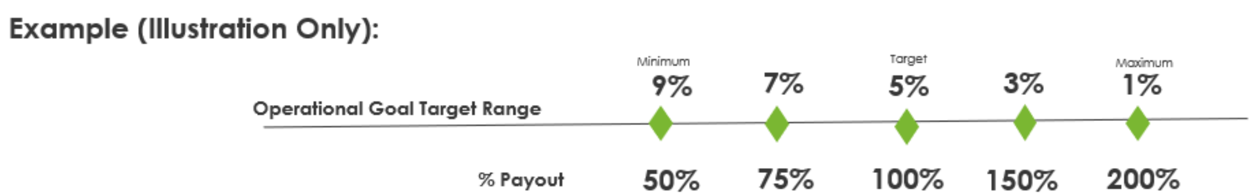
Consumers Energy incorporates individual goals through the annual performance feedback process, which includes the creation and review of individual goals and objectives for each salaried employee and the opportunity to recognize and reward individual performance. The existence of a common set of customer objectives enables supervisors and employees to establish individual goals and objectives which are supportive of, and in alignment with, the corporate goals reflected in the EICP.

Q. How are the payout levels that are shown on Exhibit A-40 (AMC-1) set?

A. When setting payout levels, threshold is set at a level of achievement that can typically be reached 80% to 90% of the time in a ten-year period. Maximum payout is for exceptional performance (10% to 20% of the time in a ten-year period). These levels are to engage the employees in meeting the goals. Employees must re-earn the incentive at-risk portion of compensation each year. If the threshold to achieve a payout were set at a level viewed as not achievable, it would be difficult to maintain employee motivation and would result in fewer customer benefits. Overall compensation levels, including the EICP at target (100%) level that Consumers Energy seeks, are not excessive. It is reasonable for Consumers Energy to pay its employees competitive levels of compensation.

Q. Are the payout levels that are shown on Exhibit A-40 (AMC-1) similar to 2023 and the projected test year?

A. Yes, each operational measure will have its own threshold, target, and maximum for payout. This practice aligns better to market practice and with engaging and motivating performance. Gallup research supports substantial and well-established connections between employee engagement and the achievement of outcomes critical to the business and to customers. See illustration of banded goals below:



This structure was in place for 2023 and planned to be in place for the projected test year.

Q. Why are you including both gas and electric performance measures in this plan as this is a gas rate case?

A. For purposes of efficiency and improved service, the Company has combined operations as one organization. For that reason, the plan contains both gas and electric measures.

Q. How are the targets for the annual officer EICP incentives measures determined?

A. As mentioned earlier, the goals are the same for the officer and non-officer EICPs, but the weightings are different.

Q. Why is the weighting different for the officer plan?

A. Officer annual incentive awards were based on the achievement of EPS and utility operational goals for the historical test year. As indicated above, the officer plan has a 30% weighting of the same operational goals as non-officers. This strengthens the linkage of officer and non-officer performance while aligning with typical indicators of officer strategy execution through financial goals (weighted at 70%) and corresponding higher weighting.

Q. How are the target amounts for the annual officer incentives determined?

A. The Compensation Committee determines the target amounts of the annual officer incentives. In determining the amount of target incentives, the Compensation Committee considers the following factors:

- The target incentive level and actual incentives paid in recent years;
- The relative importance, in any given year, of each performance goal established; and
- The advice of the Compensation Committee's compensation consultant as to compensation practices at other companies in the Compensation Peer Group and the utility industry.

B. <u>Assessment of Customer Benefits of the Incentive Compensation Plans</u>

Q. What level of expenses for Consumers Energy's incentive plans has been included in the test year revenue requirement?

A. The Company is requesting recovery of gas O&M expenses related to EICP incentive compensation plans at target (100.0%) levels. The following is a listing of the goals illustrated in Exhibit A-42 (AMC-3) for which the Company is requesting recovery:

- **Employee Safety** (OSHA Recordable)
  (Incidents, High Risk Injuries and Zero fatalities)
- **Culture Index**
  (Employee Empowerment, Employee Engagement and DEI)
- **Customer Experience** - Cxi
  (Survey measuring Customer Experience)
- **Electric Reliability** - SAIDI
  (System Average Interruption Duration Index)
- **Methane Emission Reduction**
  Reduction of Methane Emissions through replacements of Mains and Services, etc.)

The level of expense is approximately $1.5 million as illustrated in Exhibit A-42 (AMC-3).

Q. Please explain Exhibit A-42 (AMC-3).

A. Exhibit A-42 (AMC-3) presents the amounts of the projected O&M expenses that were developed by applying either an inflation rate or a merit increase rate to historical O&M expense. Page 2 column (b) shows the historical O&M expense. Column (c) shows the historical amount that an inflation or labor rate or rate was applied to. Columns (e) and (g) show the amounts to which an inflation rate or labor increase rate were applied for each bridge period, respectively. Columns (d), (f), and (h) show the labor and inflation increases for each respective period. Amounts that were projected using other methods are included in column (i). Column (j) is the projected test year O&M and is the sum of columns (b), (d), (f), (h), and (i). For purposes of incentive expense only labor increase is applicable. No inflation rate was applied. The labor or merit rate used is based on the cost of labor factor described in Company witness Heather L. Rayl workpaper WP-HLR-44.

Q. How are the gas expenses of $1.5 million related to annual incentive compensation calculated?

A. The $1.5 million for EICP incentive compensation is based on the following:

- For officers: The rate case expense amount is based on 2022 salaries multiplied by the approved target incentive percentage of salary from the 2022 Compensation & Human Resources Committee of the Board of Directors. Factors that impact the incentive expense year-over-year are retirements of officers and successors being at lower incentive amounts (decrease expense) forecasted salary increases (increase expense), and addition of new officers (increase expense) as indicated below.

- For non-officers: The rate case expense amount is based on an estimate of the number of employees in each salary grade multiplied by the plan prescribed incentive target amount. Progression to higher job levels as employees gain additional work experience will increase the amount of incentive expense year over-year and headcount reductions will decrease the amount of incentive expense year-over-year.

Q. How was the gas portion of the incentive compensation expense determined?

A. The allocation percentages were supplied by the Accounting Department.

Q. Is a portion of the gas incentive compensation expense allocated between O&M and capital?

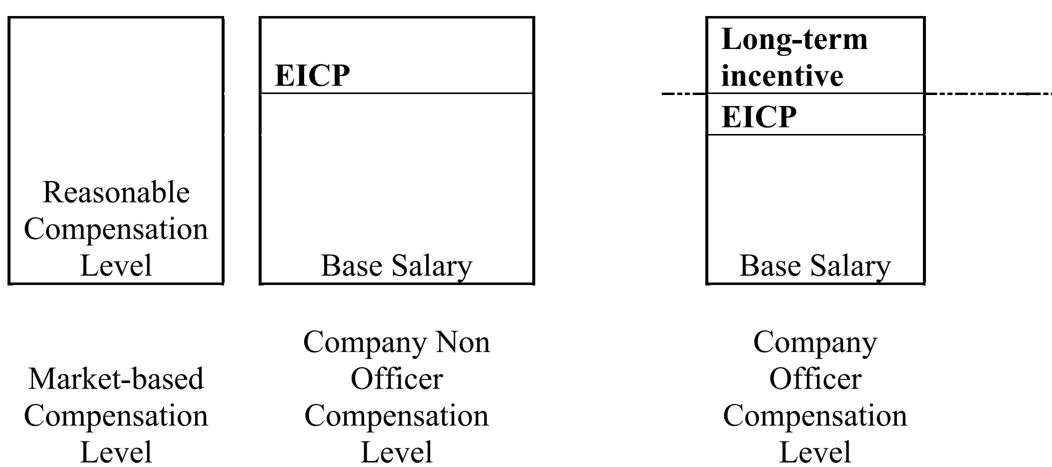
A. Yes. In the Company's 2014 Electric Rate Case, Case No. U-17735, the Commission issued an Order on November 19, 2015, approving the recovery of annual incentive (EICP) in rates for non-officers and non-proxy officers. As a result, in the first quarter of 2016, the Company began classifying annual incentive expense for the approved employee groups as a labor cost. The labor percentages charge between O&M and capital is based on labor studies performed by each business unit for the operational goals portion of the cost. Costs associated with financial performance measures are charged to O&M only.

Q. Do Consumers Energy's gas customers benefit from making a portion of employee compensation subject to incentives?

A. Yes. Paying a competitive level of compensation is an essential prerequisite to being able to attract, retain, and motivate qualified employees. Consumers Energy has determined a reasonable level of compensation and then made a portion of that compensation at risk. Structuring employee compensation so that it includes both base pay and incentive compensation provides motivation for an employee to strive for the total compensation for their position by contributing to the achievement of performance measures. Customers receive both qualitative and quantitative benefits at no additional cost above market-based compensation.

Q. Why do you say there is no additional cost above market-based compensation?

A. The officer and non-officer incentive plans are designed so that the total base salary plus incentive payments will be equivalent to the market-based compensation level. The EICP is part of the overall reasonable level of market-based compensation. It is not in addition to it. This is illustrated in the following diagram:



Q. What is the appropriate standard from a business perspective in evaluating the reasonableness of the EICP costs?

A. Making a portion of compensation subject to incentives is a recognized, well-established, common practice in the utility industry and is reasonable and appropriate. The appropriate standard from a business perspective in evaluating whether the level of compensation is reasonable is whether the *overall* level of compensation, including both base salary and incentive compensation, is reasonable. Using this standard would also be appropriate for ratemaking purposes. Looking at whether the overall level of compensation is reasonable will provide a better indication of whether the incentive plan results in excess rates than attempting to examine the cost allocable to the incentive compensation compared to benefits to customers. The overall level of compensation that Consumers Energy has included in its request in this case is reasonable.

Q. Under the Company's proposal, do shareholders bear a portion of the EICP costs?

A. Yes. The Company's incentive compensation proposal in this case does result in shareholders bearing a portion of incentive costs. The Company's proposal to include incentive compensation costs at target levels will result in the Company absorbing the incentive compensation costs in those years when the actual payouts are greater than target level and for the financial performance measures' cost. Thus, shareholders will absorb any resulting increase in costs arising from above-target performance and for financial measures. If actual payouts in future years are less than target levels due to under performance, then the Company's shareholders will absorb the consequence of underperformance results along with customers. The Company is allocating to shareholders 100% of the costs of incentive compensation for above-target performance and financial measures.

Q. Is the payment of incentive compensation reasonable given the economic conditions facing the Company's customers?

A. Yes. The incentive compensation costs are reasonable costs of doing business. The market median of survey data reflects current economic conditions and current pay practices. The Company maintains an annual practice of surveying the external market. Any trends in compensation – increases/decreases – would be reflected in the market survey results. Paying a reasonable level of compensation is rational and is in the best interests of the Company's customers. Incentive compensation does not result in excessive compensation and is reasonably necessary to attract, retain, and motivate a talented workforce to serve our customers. Further, gaps between the skills that employers require and those available in the labor market are growing. Paying a reasonable level of compensation which includes incentive compensation is necessary to attract, retain, and motivate a talented workforce. As of December 2022, the unemployment rate was 4.3% in Michigan and 3.5% nationally, according to the Bureau of Labor Statistics ("BLS"). In addition, BLS data show that there are more job openings in the United States than there are unemployed people. The war for talent is real, and we must offer a compelling value proposition to attract and retain the talent required to realize our company purpose of world-class performance delivering hometown service.

Q. Is the EICP a bonus or profit-sharing plan?

A. No. The EICP is not a bonus or profit-sharing plan. A bonus is a discretionary payment given without predetermined goals or objectives and a profit-sharing plan entitles employees to a share of the profits of the Company without pre-determined goals or objectives and is not part of total cash compensation market levels. Consumers Energy offers incentive compensation, which is based on predetermined goals and objectives and award levels. Incentive compensation is part of an employee's overall compensation and not in addition to it, like a bonus or profit-sharing plan. The fact that a portion of compensation is in the form of an incentive payment does not mean that employees are paid in excess of market rates when they receive their incentive payment. Employee compensation is a reasonable cost of doing business. If overall compensation levels are reasonable, then those costs should be recoverable through utility rates.

Q. What are some of the ways the EICP incentives benefit customers?

A. Customers derive benefits by having a portion of compensation shifted to the EICP Program since the goals of the program are in the interests of customers. Customer benefits are achieved without any additional cost to customers since this program has been structured as a "carve out" of the employee's base salary. If the EICP costs had not been allocated to incentive compensation, those costs would need to be recovered as base compensation for Consumers Energy to have a reasonable competitive level of compensation.

Also, customers are best served when Consumers Energy can attract, retain, and motivate talented salaried employees and executives with compensation packages that are competitive and fair. Performance-based incentives (like Consumers Energy's) permit the Company to provide an incentive to accomplish specific annual goals that represent performance priorities for Consumers Energy and its customers. With variable pay, the employee and the Company must re-earn the incentive award every year. If performance goals are not achieved, cash compensation is reduced or eliminated. Variable pay creates a performance culture rather than an entitlement culture.

In addition, an incentive program structured to focus employee attention on operational performance results in both qualitative and quantitative customer benefits. Among other things, customers benefit from increased cyber security, reliability, and on-time delivery and the focus on employee and public safety that helps reduce potential increased costs.

A quantitative analysis of the benefits received by the customer as a result of the EICP is discussed by Company witness Stuart in his direct testimony in this case.

Q. Has Consumers Energy assessed whether benefits to customers of this program equal or exceed costs?

A. Yes. The performance measures provide appreciable benefits to customers. The costs of the EICP are projected at approximately $1.5 million for the test year. The quantifiable gas benefits illustrated in Company witness Stuart's direct testimony are $3.1-$4.2 million, which shows that the benefits to customers of the Company's EICP Program outweigh the costs of the program. Since this amount is part of the overall level of reasonable compensation, rather than being in addition to it, all benefits to customers are achieved at zero additional cost to customers. Achievement of the Company's EICP goals and objectives result in pay that is competitive with the labor market, not above the market. The EICP costs are not in addition to the reasonable level of compensation, they are part of the reasonable level of market-based compensation. If these amounts are not paid, then overall compensation would be at a level which is below the market level. There is no valid basis to eliminate incentive costs from the cost of service recovered in rates because they are a part of an incentive plan rather than including these costs as part of base pay. As stated before, overall levels of compensation are at levels that are not excessive. Rate recovery of 100.0% should be allowed.

IV. <u>CONCLUSION</u>

Q. Is the Company's overall compensation program, including the customer-focused incentive, reasonable?

A. Yes. The approach used by the Company is a reasonable approach, is consistent with industry standards, and represents well-established best practices for creating customer focus through compensation design, and it does so without any additional customer cost above the market. The overall compensation levels are reasonable relative to the market, are determined in a reasonable manner, and are a reasonable cost of doing business. Compensation is structured in a manner that rewards improved operational and financial performance that benefits customers. The incentive compensation costs should, therefore, be included in the cost of service recovered from customers. These are legitimate and reasonable costs of doing business. Rates established in this rate case should include approximately $1.5 million for incentive compensation expense.

Q. Please summarize reasons why full recovery of incentive compensation costs should be allowed in this case.

A. Reasons that full recovery of operational goal incentive compensation costs should be allowed include the following:

- Employee compensation is a reasonable cost of doing business, has been set at a reasonable level, and has been determined using a reasonable methodology;
- The amount of compensation that is subject to incentive measurements is part of the market-based compensation level, not in addition to it;

- The incentive compensation plan does not result in excessive pay levels beyond what is reasonably necessary to attract a talented workforce to best serve the customer;
- Making a portion of compensation subject to incentives is a recognized, well-established, and common industry practice and is neither irrational nor unreasonable;
- The decision of Consumers Energy to allocate a portion of overall compensation that would otherwise have been in base pay so that it is subject to incentives does not provide a valid basis to disallow these expenses;
- The plan incorporates operational as well as financial performance goals;
- Quantitative and qualitative customer benefits of having a portion of compensation subject to incentives occur at no additional cost above market-based compensation to customers given the compensation structure adopted;
- Investors, including shareholders, bear the expense of incentive compensation in excess of the target levels and for incentive compensation provided to proxy officers; and
- The focus should be on whether the overall level of compensation is reasonable, not on the precise structure of the compensation program.

It is reasonable for Consumers Energy to pay its employees competitive levels of compensation. Paying employees at competitive market levels is reasonable and prudent. Those incentive pay costs are reasonable costs of doing business and are recoverable from customers.

Q. Does this conclude your direct testimony?

A. Yes.

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the application of	)	
CONSUMERS ENERGY COMPANY	)	
for authority to increase its rates for the	)	Case No. U-21490
distribution of natural gas and for other relief.	)	
	)	

DIRECT TESTIMONY

OF

NEAL P. DREISIG

ON BEHALF OF

CONSUMERS ENERGY COMPANY

December 2023

Q. Please state your name and business address.

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

Q. By whom are you employed?

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

Q. What is your position with Consumers Energy?

A. I am a Senior Strategy Manager in the Gas Strategy Department, a position I have held since March 2020.

Q. What are your responsibilities as Senior Strategy Manager?

A. As Senior Strategy Manager, I am responsible for the cross-functional research, analysis, and oversight of decarbonization related assets and portfolio management strategy. This includes the development, recommendation, and administration of the Natural Gas Delivery Plan ("NGDP").

Q. What is your educational background?

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

Q. Do you have any professional certifications?

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

Q. What is your work experience?

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

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

A. Yes, I have previously provided testimony in the following cases:

- Case No. U-20893, the Company's Investment Recovery Mechanism Reconciliation;
- Case No. U-21141, the Company's Voluntary Carbon Offset Program;
- Case No. U-21148, the Company's General Gas Rate Case; and
- Case No. U-21308, the Company's General Gas Rate Case.

Q. What is the purpose of your direct testimony?

A. The purpose of my direct testimony is to provide an overview of the Company's natural gas transmission, distribution, storage, and compression systems, and an updated version of the Company's 10-year plan called the *Natural Gas Delivery Plan* per Exhibit A-43 (NPD-1).

Q. Are you sponsoring any exhibits?

A. Yes. I am sponsoring the following exhibits:

Exhibit A-43 (NPD-1)	Natural Gas Delivery Plan

Q. Was this exhibit prepared by you or under your direction and supervision?

A. Yes.

Q. What is the purpose of the NGDP?

A. The NGDP provides a transparent investment plan for the next decade for the Company's natural gas assets. This investment plan framework considers safe and reliable gas supply, how the Company plans to evolve its assets in accordance with the Gas Pipeline industry standard American Petroleum Institute Recommended Practice 1173 Pipeline Safety Management Systems framework. Additionally, it develops a strategic framework in response to decarbonization goals of the Company's natural gas customers and future carbon policy relevant to the utility. The Company's most recent update to the NGDP is included in this rate case as Exhibit A-43 (NPD-1).

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

A. Yes. Consumers Energy's natural gas system contains 2,371 miles of transmission pipelines, more than 28,277[1] miles of distribution mains, and approximately 1.6 million[2] services providing natural gas to approximately 1.8 million customers. The Company operates 7 compressor stations on the transmission system, 1 compressor station on the distribution system, and has 15 underground storage fields. Consumers Energy receives natural gas supply into its transmission system with varying maximum allowable operating pressures. Consumers Energy's transmission system provides reliable supply to its customers by using compressor stations to bring natural gas onto its transmission system and leverages storage fields to balance supply with customer demand. The transmission system supplies natural gas to city gates, which deliver gas to the distribution system. The

[1] Source: U.S. Department of Transportation, Gas Transmission & Gathering System Annual Report for Calendar Year 2020 submitted 03/11/2021.

[2] Source: U.S. Department of Transportation, Gas Distribution System Annual Report for Calendar Year 2022 submitted 03/12/2023.

Company's distribution system moves gas from city gates through pressure regulation stations into neighborhoods and commercial and industrial districts to customer homes and businesses.

Q. Please describe investments the Company has made and how they benefit customers.

A. From 2018 through 2022, the Company prudently invested over $4.7 billion in its gas system for safety, reliability, deliverability, system integrity, and customer service. Key investments were made across the distribution, transmission, compression and storage asset classes, described below.

The Company replaced 494 miles of higher relative risk pipe via the Enhanced Infrastructure Replacement Program ("EIRP") and replaced or retired more than 46,000 services to improve customer safety and reliability.

The Company replaced 79 miles of transmission pipe under the Transmission Enhancement for Deliverability and Integrity ("TED-I") Program. These replacements reduce risk, increase capacity where needed, and better control gas flow.

The Company optimized its compression portfolio by completing the Freedom Compressor Station Upgrade while at the same time reducing horsepower by approximately 20,000 with no impact to customer deliverability.

The Company reduced the number of storage field wells by 143 in support of the 2017 Pipeline and Hazardous Materials Safety Administration ruling to return all wells to "like-new" condition. Well remediation reduces methane leakage, risk tied to corrosion, and improves gas deliverability per well.

The Company also made additional investments in city gate modernization, remote control valves, regulator stations and information technology to improve public safety, ensure reliability, and optimize gas flow deliverability.

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

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

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

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

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

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

Q. What are the main objectives for the NGDP?

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

1. **Safe** – Safety remains top priority. The Company seeks to reduce the probability of incidents that could adversely affect public safety, customers, and employees. This means:

   - Reduce system risk across asset classes through inspection and replacement of vintage materials in mains and services. Investment examples of this include EIRP, TED-I, pipeline integrity, and Well Logging and Rehabilitation Program;

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

2. **Reliable –** The Company continues to create a reliable and resilient system, measured through metrics such as gas flow deliverability to avoid unplanned outages. Resiliency is defined as the gas system's ability to prevent, withstand, adapt to, and quickly recover from a high-impact, low-likelihood event and essential for safe and continuous customer service. The Company continuously evaluates the balance between system reliability, resilience, and optimization.

Investment examples of this include the Mid-Michigan pipeline replacement, compressor station upgrades, maintenance plans, and remote control valves.

3. **Affordable** – The Company's investments including those in technology and automation improve safety and reliability, which can be made while maintaining stable, predictable, and reasonable growth in total bills. These investments will remain a small percentage of household spending while providing a valuable and fundamental product that is safe, reliable, and improves quality of life.

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

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

   - Customer Programs: In 2022, the Company received approval for a voluntary program for natural gas customers to offset carbon emissions associated with natural gas use through Michigan-based forest preservation. Accordingly, the Company launched the MI Clean Air Program; and

   - Renewable Natural Gas ("RNG"): The Company continues to investigate how to cost-effectively produce and deliver RNG as part of its supply portfolio. RNG captures, conditions, and repurposes greenhouse gas emissions from organic waste as a potentially carbon negative drop-in fuel for use across the system.

Please refer to the NGDP, Exhibit A-43 (NPD-1), for further elaboration on the Company's efforts to improve its performance in this area along with the testimony and exhibits of Company witness Lincoln D. Warriner for distribution capital; Company witness Timothy K. Joyce for compression and storage capital; Company witness Kristine A. Pascarello for material condition distribution capital and engineering operations and maintenance; and Company witness Michael P. Griffin for transmission capital and pipeline integrity.

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

A. Yes. As Consumers Energy moves forward with the NGDP, there will be intentional actions by the Company in the operational capabilities of people, process, and technology for each of the asset areas to enable the 10-year objectives, goals, and outcomes to be successfully achieved. As described in the NGDP, Exhibit A-43 (NPD-1), technology (*i.e.,* information technology) or digital projects enable the expected NGDP future outcomes. Company witness Stacy H. Baker includes, in her direct testimony, technology projects that are critical in supporting gas functions including gas Supervisory Control and Data Acquisition software, the gas storage probabilistic and gas compression probabilistic risk model project, and the gas transmission, distribution and compression historians.

Q. Will all of the projects in this testimony support achieving the objectives and outcomes in the NGDP?

A. Yes. As described in the NGDP, Exhibit A-43 (NPD-1), the activities outlined above represent the Company's 10-year plan. Fully funding both the capital and operating and maintenance costs for the NGDP projects and executing the projects, will position the Company to achieve predictable, prudent, and affordable outcomes throughout the 10 years of the NGDP.

Q. Does this conclude your direct testimony?

A. Yes.

S T A T E O F M I C H I G A N

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter 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-21490

DIRECT TESTIMONY

OF

MATTHEW J. FOSTER

ON BEHALF OF

CONSUMERS ENERGY COMPANY

December 2023

Q. Please state your name and business address.

A. My name is Matthew J. Foster, and my business address is One Energy Plaza, Jackson, Michigan 49201.

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

A. I am a Principal Rate Analyst for Consumers Energy Company ("Consumers Energy" or the "Company").

Q. Please state your educational background.

A. I graduated from Michigan State University with a Bachelor of Business Administration with a major in finance.

Q. What are your responsibilities in your current position?

A. In my role as a Principal Rate Analyst, I am responsible for the development of Capital and Operations & Maintenance ("O&M") plan targets that align with rate case results.

Q. Please describe your prior work experience.

A. I have held my current position since April 2018. Prior to this role, I held various accounting analyst roles within the finance organization, including in the General Accounting and Property Accounting Departments. In these roles, I have been responsible for property records, depreciation analysis, financial results, accounting entry, analysis, and reporting, including Federal Energy Regulatory Commission ("FERC") and Michigan Public Service Commission ("MPSC" or the "Commission") report filings.

Q. Have you previously testified before the Commission?

A. Yes. I testified in Case Nos. U-21224, U-21308, and U-21389, which include the Company's most recent natural gas and electric general rate cases.

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

A. My direct testimony is in five parts. In Part 1, I am presenting testimony supporting the test year O&M expense for Corporate Services, uncollectible expense, injuries and damages, and Manufactured Gas Plant ("MGP") direct project management costs. In Part 2, I address the test year capital expenditure for Corporate Services. In Part 3, I address technology projects that support the Corporate Services functions. In Part 4, I am presenting testimony requesting approval for the use of regulatory assets or regulatory liabilities, as needed, by the Uncollectible Deferral/Refund Mechanism, and the Defined Benefit ("DB") Pension/Other Post-Employment Benefits ("OPEB") Volatility Mechanism. In Part 5, I am presenting testimony demonstrating Consumers Energy's compliance with the guidelines for intercompany transactions between affiliates as ordered by the Commission.

Q. Are you sponsoring any exhibits in this proceeding?

A. Yes. I am sponsoring the following exhibits:

Exhibit A-44 (MJF-1)	Summary of Projected Gas & Common O&M Expense for the Years 2022, 2023, 2024; and the 12 Months Ending September 30, 2025;
Exhibit A-45 (MJF-2)	Gas Projected Corporate Services O&M Expense for the Years 2022, 2023, 2024; and the 12 Months Ending September 30, 2025;
Exhibit A-46 (MJF-3)	Gas Uncollectible Accounts Expense for the Years 2022, 2023, 2024; and the 12 Months Ending September 30, 2025;
Exhibit A-47 (MJF-4)	Gas Injuries and Damages Expense for the Years 2018 through the 12 Months Ending September 30, 2025;

Exhibit A-48 (MJF-5)		Manufactured Gas Plant Amortization Schedule and Direct Project Management Costs 2005 through the 12 Months Ending September 30, 2025;
Exhibit A-49 (MJF-6)		Organization Chart, Affiliate Group of Companies Doing Business with Consumers Energy Company – 2022; and Purpose of Business, Affiliate Group of Companies Doing Business with Consumers Energy Company – 2022;
Exhibit A-50 (MJF-7)		Summary of Costs Billed to Affiliated Companies for the Year Ended December 31, 2022; and Summary of Payments Made to Affiliated Companies for the Year Ended December 31, 2022;
Exhibit A-51 (MJF-8)		Impact on Gas Operations for Costs Billed to Affiliated Companies for the Year Ended December 31, 2022;
Exhibit A-52 (MJF-9)		Impact on Gas Operations for Payments Made to Affiliated Companies for the Year Ended December 31, 2022;
Exhibit A-53 (MJF-10)		Affiliated Companies – Rate of Return on Common Equity for the Year Ended December 31, 2022;
Exhibit A-54 (MJF-11)		2022 Gas Utilities Ranked by A&G per Customer (less Pension and Benefits); and
Exhibit A-12 (MJF-12)	Schedule B-5.4	Gas Projected Corporate Services Capital Expense for the Years 2022, 2023, 2024; and the 12 Months Ending September 30, 2025.

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

A. Yes, they were.

PART 1 – GAS CORPORATE O&M EXPENSE

Q. Please describe Exhibit A-44 (MJF-1).

A. Exhibit A-44 (MJF-1) summarizes the Company's total 2022 through the 12 months ending September 30, 2025 gas O&M expense for Corporate Services, uncollectible expense, injuries and damages, and MGP direct project management costs. Column (a) of this exhibit provides the O&M expense category, column (b) provides the source references, column (c) provides the 2022 actual O&M, column (d) provides the 2023 O&M projection, column (e) provides the 2024 O&M projection, and column (f) provides the projected test year 12 months ending September 30, 2025 O&M expense. These expense categories are discussed in detail below.

Corporate Services O&M Expense

Q. What areas are included within the Corporate Services O&M expense category, as shown in Exhibit A-44 (MJF-1), line 1?

A. Corporate Services includes those areas common to the administrative functions of a regulated corporation. These include Sustainability and External Affairs; Legal, Ethics, Regulatory and Risk Management; People and Culture ("P&C"), Learning and Development; Finance and Shared Services; Strategy; General Activities; and administration and other costs.

Q. Please provide a brief overview of the various areas within the Corporate Services area.

A. The areas within Corporate Services include:

- Sustainability & External Affairs – This area acts as a conduit between the Company and its employees, customers, and external stakeholders. The group manages storm communications, promotes safety messaging, advances clean energy programs for the benefit of customers via public media relations and inquiries, advertising, corporate news releases, social media management, and trade association dues and memberships. This area also manages regulatory commission expenses, foundation operations, and community programs. It is responsible for employee diversity and inclusion and strategic talent sourcing;

- Legal, Ethics, Regulatory, and Risk Management – This area includes the Legal Organization, the Corporate Compliance Department, the Corporate Secretary Department, the Securities Law Group, Corporate Information Governance, Risk Management, and it is responsible for determination and management of regulatory filings, and management of the interface between the Company and regulatory staffs. The Corporate Compliance Department is responsible for maintaining a healthy ethical culture, including training on the Company's Code of Conduct and Guide to Ethical Business Behavior, misconduct investigations, and oversight for 40 regulatory compliance areas. The Corporate Secretary Department is responsible for sound corporate governance, including board meetings, shareholder meetings, minutes, shareholder services, and Board of Directors costs. The Securities Law Group is responsible for ensuring full and fair disclosure to investors through compliance with public-company regulatory and legal requirements. Corporate Information Governance is responsible for creating and sustaining a company culture where all employees treat information as an asset, including adherence to the information governance principles: accountability, transparency, integrity, protection, compliance, availability, retention, and disposition. The Risk Management area provides services for corporate insurance programs, surety bonds, and review of commodity and credit risks associated with natural gas, electric fuel, and power purchases. Gas and electric insurance programs include the premiums for property and casualty insurance paid to cover the business including property damage, director and officer's liability insurance, public liability insurance, workers' compensation insurance, fiduciary liability insurance, and fidelity insurance. The Legal Organization is responsible for legal matters involving litigation, credit and collections, environmental, contracts, and other transactions, real property, labor and benefits, business development, and regulatory matters at the state and federal levels;

- P&C and Learning and Development – This area is responsible for creating and executing on the employee experience for all co-workers at Consumers Energy. An engaging employee experience is critical for hiring and retaining the necessary talent to benefit customers and the State of Michigan. The employee experience is comprised of all interactions and services that employees experience during their time with the Company, including recruiting, hiring, training and development, succession planning, compensation, payroll, performance management, workforce relations, employee engagement, and benefits administration. Also included is compliance assurance, which addresses legal and regulatory requirements such as Equal Employment Opportunity, Americans with Disabilities Act, and Family and Medical Leave Act;

- Finance and Shared Services – This area provides the preparation of utility strategic plans, budgets, forecasts, and specialized financial studies. This area also includes the preparation and control of accounting records, including financial statements and reports, and the administration of accounting systems. These systems include budgeting and management reporting, general ledger, accounts payable, fixed assets, and financial and regulatory reporting. The internal audit functions (appraisal of business unit effectiveness of financial controls) and the internal control functions are conducted in this area. The corporate tax function includes all aspects of compliance with federal, state, and local income, sales and use, property, franchise, and excise taxes, book accounting for taxes, tax planning of transactions, tax research, the analysis of tax legislation and regulations, the management and negotiation of tax audits, and tax litigation. Treasury includes all aspects of Company financing and cash management, negotiation of Company credit facilities, treasury operations including initiating cash wire transfer transactions, processing checks for deposit, maintenance of all bank account related activities, borrowing, and investing. In addition, investor relations, rating agency, and investor support are included in the Finance and Shared Services area. Shared Services includes fleet and facilities asset management, corporate safety, and supply chain;

- Strategy – This area is responsible for performing analysis to generate recommendations that shape the Company's overall strategic direction. The Strategy organization manages the Company's long-term strategic planning process. Piloting of emerging technologies and customer offerings is also performed in the group;

- General Activities – These costs are an aggregation of expenses and credits that are not attributable to any one department but are incurred on behalf of the Company as a whole. Examples include capitalized credits to O&M, billing credits for Administrative and General ("A&G") labor, expenses, and outside services as part of a full-cost loading adder, and senior management time and expenses; and

- Administrative and Other – These costs are primarily for American Gas Association dues and intervenor funding.

Q. How are Corporate Services expenses allocated between the Company's electric and gas businesses?

A. Allocations are developed based upon the type of cost. For example, billing costs are allocated based on customer counts for the electric and gas business, benefits are allocated based on either employee counts or labor, general costs are allocated based on the Three Factor Allocation Method, with other costs being directly charged for identified activities, allocated based on capital and O&M spending levels and special studies.

Q. What is the Three Factor Allocation Method?

A. The Three Factor Allocation Method uses the average of three factors (Operating Revenue, Labor and Property, and Plant and Investments) to allocate costs between the electric and gas businesses.

Q. Explain how the Adjusted Corporate Services O&M was calculated.

A. Exhibit A-45 (MJF-2), line 13, provides the Company's gas portion of total Corporate Services expenses, before adjustments. The 2022 actual O&M expenses were obtained from the Company's records. Specific line-item changes are included as increases or decreases as appropriate to reflect exclusions, remove one-time costs, reflect transfers of costs into or out of the Corporate Services area, or reflect significant ongoing changes in Corporate Services O&M expense. Exhibit A-45 (MJF-2), line 16, column (d), shows the total normalizations of one-time costs from 2022 total Corporate Services expense. The 2022 Voluntary Separation Program costs and one-time Legal Consultant Expenses were removed in the normalizations line. Also, the total of items disallowed by Commission order related to advertising, lobbying, and donation payments were removed on Exhibit A-45 (MJF-2), line 19. Total adjusted Corporate Services expense is found on Exhibit A-45 (MJF-2), line 20.

Q. What is the projected rate of inflation?

A. The assumed rate of inflation is based on the Consumer Price Index ("CPI") which considers factors specific to pricing of goods and services, such as the cost of food, energy, and housing. The CPI is 4.2% for 2023, 2.7% for 2024, and 2.4% for 2025. Consumers Energy uses these inflation rates to project Corporate Services O&M.

Q. What is the source for the CPI?

A. The June 2023 edition of the IHS Markit U.S. Economic Outlook. Company witness Heather L. Rayl supports the inflation rates.

Q. In addition to increases related to inflation, what other specific line-item changes are included to arrive at the test year O&M expense projection?

A. No other changes were included.

Q. Are the costs associated with restricted stock and the Employee Incentive Compensation Program ("EICP") included in the 2022 actuals or projected Corporate Services O&M expense?

A. No. Further details regarding restricted stock and EICP expenses are covered under the direct testimony of Company witness Conrad.

Q. Is the level of test year Corporate Services O&M expense reasonable?

A. Yes. The reasonableness of the O&M expense levels is supported by the fact that Standard and Poor's ("S&P") Global Market Intelligence ranked Consumers Energy's 2022 gas A&G costs (excluding pension and benefits) the fifth lowest out of the 33 top companies ranked on a cost per customer basis for gas utility companies with more than 500,000 customers. The Company's ranking by S&P Global Market Intelligence in this regard indicates the Company's diligence in managing overhead costs. Please refer to Exhibit A-54 (MJF-11) for the report on this ranking.

Q. What is S&P Global Market Intelligence?

A. S&P Global Market Intelligence provides financial and operating data for gas and electric utility companies.

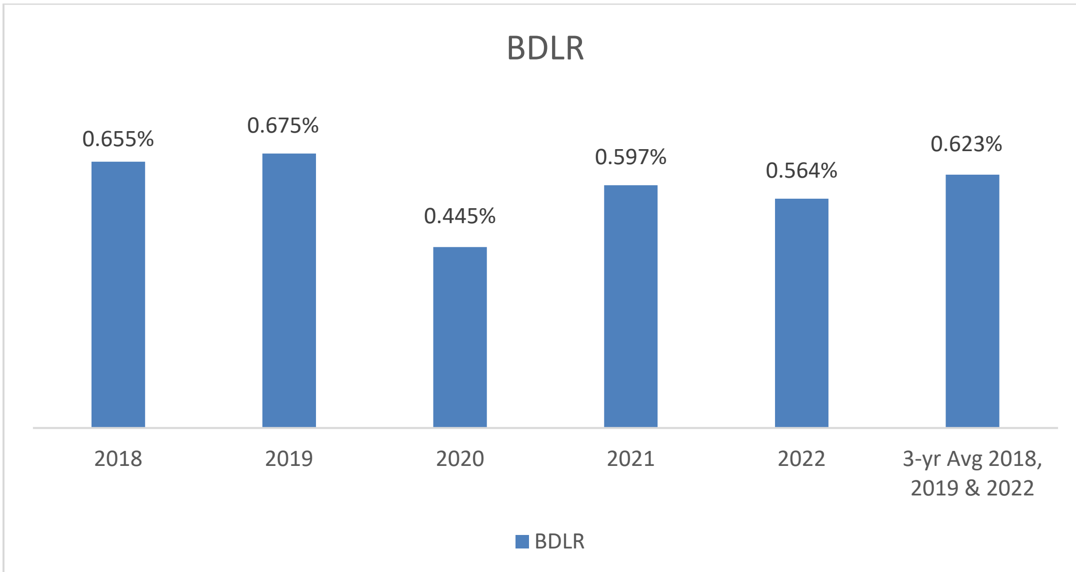
<u>Gas Uncollectible Expense</u>

Q. How did the Company determine the uncollectible expense included in the test year?

A. The Company projects the uncollectible accounts expense for the test year at $15.3 million as shown on Exhibit A-46 (MJF-3), page 1, column (e). The projected test year uncollectible accounts expense is based on a three-year historical average Bad Debt Loss Ratio ("BDLR") of uncollectible accounts expense to gas service revenue for the years 2018, 2019, and 2022, as shown on Exhibit A-46 (MJF-3), page 2. This ratio is applied to the test year gas service revenue, plus energy waste reduction surcharge revenue, to arrive at test year uncollectible accounts expense on Exhibit A-46 (MJF-3), page 1, line 1, column (e).

Q. Why did the Company use a three-year average BDLR using 2018, 2019, and 2022 versus the most recent three-year average BDLR 2020 through 2022?

A. As a result of the COVID-19 pandemic, 2020 had several actions taken by government authorities and the Company that resulted in a low BDLR rate that does not reflect expected future conditions. Notably, in 2020 the Federal Government passed the American Rescue Plan Act that included support through expanded unemployment benefits and energy assistance. In addition, the Company suspended dunning, provided good faith credits to customers, and leveraged government support to assist customers. The effects of the government programs and Company initiatives carried over into 2021, lowering the 2021 BDLR. The below chart shows the meaningful reduction in BDLR in 2020 and 2021 which is not representative of the projected test year. To adjust for this anomaly, the Company used the three-year average 2018, 2019, and 2022 which is more reflective of the Company's recent experience prior to the pandemic.



Q. Does the estimate of test year uncollectible accounts expense consider changing natural gas prices, their impact on customer bills, and the corresponding impact on uncollectible accounts expense?

A. Yes. By using the test year revenues in the calculation, the latest gas commodity cost projections are taken into account.

Q. Does this method provide a reasonable estimate of uncollectible expense?

A. Yes. The Company continuously strives to reduce uncollectible accounts expense. However, year-over-year, uncollectible accounts expense can be impacted by many factors. The economy, the effectiveness of collection practices, funding of low-income assistance programs, extreme weather fluctuations, or any number of other factors that could impact customers' ability to pay. The Company cannot predict which, and to what extent, the future impact of any one of these factors could have on uncollectible expense. As a result, the Company is proposing a three-year average 2018, 2019, and 2022 BDLR in this rate case filing. This method most effectively captures the recent trends in the Company's BDLR rate without Government or Company payment assistance programs.

Q. What mitigation strategies has the Company used to manage uncollectible expense?

A. Over the last several years, the Company has implemented several mitigation strategies serving to reduce uncollectible expense. First, turn on compliance was implemented to stop the cycle of carrying a past-due balance to a newly opened account. Processes were put in place that required customers with an unpaid balance to pay the old balance in full, prior to opening a new utility account. Second, the Company prioritized collection activities on high risk and high volume past due accounts to reduce the overall Company arrears balance. In addition, the implementation of smart meters has helped to reduce uncollectible expense through automated turn-off capability.

Q. Are there any other proposals that the Company is making with regards to uncollectible expense?

A. Yes. The Company is proposing an uncollectible deferral/refund mechanism in this case. This mechanism would allow the Company to defer the difference between uncollectible accounts expense included in rates versus the actual expense recorded by the Company. The Company further proposes that any deferred amounts be considered for collection or refund in a future rate case.

Q. Why is a deferral/refund mechanism necessary at this time?

A. This mechanism is necessary due to the greater than normal uncertainty around uncollectible expense. The impacts of inflation and the availability of customer payment assistance have an unpredictable impact on the ability of many customers to pay bills.

Q. Do customers benefit from the deferral /refund mechanism?

A. Yes. There is uncertainty regarding the amount of funding that will be available to assist customers who are not able to pay their utility bills. This funding has a direct impact on and reduces the uncollectible expense of the Company. This mechanism protects customers in the event that actual uncollectible expense is less than amounts included in rates. In this situation, customers would be afforded a refund of the difference in a future rate case.

Gas Injuries and Damages Expense

Q. Please describe Exhibit A-47 (MJF-4).

A. Exhibit A-47 (MJF-4) summarizes the Company's total 2018 through 2022 actual gas injuries and damages expense and projected injuries and damages expense through the 12 months ending September 30, 2025.

Q. Please describe the costs related to injuries and damages.

A. Gas injuries and damages include liabilities that arise in the normal course of Company business for various types of items such as compensation for damaged trees and crops; restoration of driveways, lawns, and fences; and accidents and lawsuits that are below the various insurance deductibles or are otherwise uninsurable events. Further, workers' compensation costs are included in injuries and damages along with associated internal legal costs.

Q. What expense level is the Company proposing to recover in this case as part of the test year?

A. The Company is proposing that a total of $2.4 million be included for the test year as shown on Exhibit A-47 (MJF-4), line 4, column (i).

Q. How was this amount determined?

A. The injuries and damages expense is comprised of three components: gas injuries and damages, internal legal costs, and workers' compensation costs. Exhibit A-47 (MJF-4), line 1, reflects the gas property and liability damages. Line 2 represents the amount of internal legal costs that are charged to injuries and damages. Line 3 represents the level of workers' compensation costs for each year. The test year amounts for each of the three components of total injuries and damages expense is based on a five-year average of actual expense for the years 2018 through 2022.

MGP Site Remediation and Direct Project Management Costs

Q. How did the Commission previously address environmental investigation and remediation expenditures at former MGP sites?

A. In Case No. U-10755, the Commission approved deferred accounting for these expenditures, with amortization over 10 years, beginning the year after expenditures are incurred. The approach adopted by the Commission envisioned that prudence reviews would occur in rate cases and that following a prudence review: (i) the amortization expense would be included in rates, and (ii) the deferred balance would be included in rate base and would earn a return at the authorized rate of return. The approach adopted by the Commission also provided for deferred accounting and amortization of third-party recoveries in excess of the costs of recovery over 10 years, the inclusion of the unamortized balance in rate base, and deferred tax accounting. In Case No. U-13000, the Commission upheld this accounting treatment.

Q. Please explain Exhibit A-48 (MJF-5), page 1, line 1, which provides deferred cash expenditures for MGP remediation costs.

A. Line 1 shows deferred cash expenditures for MGP remediation costs for years 2005 through 2022 and projected expenditures through December 31, 2023.

Q. Why are you including projected expenditures through December 31, 2023 and not through the projected test year ending September 30, 2025?

A. I am including projected expenditures through December 31, 2023 to reflect an estimate of actual expenditures that will be available for review by MPSC Staff ("Staff") during this case. Actual expenditures available through the date of Staff's review will be made available at that time.

Q Please explain the remainder of Exhibit A-48 (MJF-5), page 1.

A. Line 2 shows the third-party insurance recoveries for the years 2005 through 2022 and projected recoveries through December 31, 2023. Lines 3 through 21 show the annual amortization of these deferred MGP remediation costs using a 10-year amortization period. Amortization of the third-party recoveries on line 2 is shown on line 22 and acts as a credit to the amortization of expenditures identified in this case. Line 23 is the net MGP amortization expense. It should be noted that until these expenditures are incorporated in a future order, the Company is required to absorb the associated carrying cost and amortization of these costs. Net amortization expense on Exhibit A-48 (MJF-5), page 1, line 23, is included in Exhibit A-13 (HLR-43), Schedule C-6, of Company witness Heather L. Rayl.

Q. Please explain Exhibit A-48 (MJF-5), page 1, line 24.

A. Line 24 is the project management costs that the Commission provided for recovery as direct costs rather than deferred and amortized costs as part of its Order in Case No. U-14547. The change became effective for the calendar year 2006 onward. These costs are carried forward to line 4 of Exhibit A-44 (MJF-1).

Q. Please explain Exhibit A-48 (MJF-5), page 2, related to the rate base treatment of the MGP unamortized balance.

A. Exhibit A-48 (MJF-5), page 2, provides the net unamortized balance of actual deferred MGP remediation costs and third-party recoveries for the years 2005 through 2022 and projected balances for the year 2023. Column (b) reflects the average unamortized balance to be included in rate base for the test year. Columns (c) and (d) reflect the year-end balances for the 12 months ending September 30, 2024 and 12 months ending September 30, 2025. Column (e) reflects the original costs of the deferred expenditures and third-party recoveries by year.

Q. What ratemaking treatment is the Company proposing in this proceeding for MGP environmental costs?

A. The Company is requesting that the Commission: (i) find that the costs sponsored by Company witness Heather M. Prentice, are reasonable and prudent; (ii) authorize recovery of amortization expense in the amount of $8.0 million as provided on Exhibit A-48 (MJF-5), page 1; (iii) approve test year direct project management costs of $0.9 million as provided on Exhibit A-48 (MJF-5), page 1; and (iv) include the deferred net unamortized balance in the amount of $28.9 million in rate base as provided on Exhibit A-48 (MJF-5), page 2.

PART 2 – GAS CORPORATE SERVICES CAPITAL EXPENDITURE

Q. Please describe Exhibit A-12 (MJF-12), Schedule B-5.4.

A. Exhibit A-12 (MJF-12), Schedule B-5.4, summarizes the Company's total 2022 through the 12 months ending September 30, 2025, gas capital expenditures for Corporate Services. Column (a) of this exhibit provides the description; column (b) provides the 2022 actual capital; column (c) provides the projected 2023 capital; column (d) provides the projected nine months ending September 30, 2024 capital; column (e) provides the projected 21 months ending September 30, 2024 capital; and column (f) provides the projected test year 12 months ending September 30, 2025 capital of $0.4 million. Categories of expenses include costs to equip and support Corporate Services areas primarily at Company headquarter locations with office furniture and equipment.

Q. Please explain how the projected Corporate Services Capital expense was calculated.

A. The 2022 actual Capital expenses were obtained from the Company's records and subsequent costs were projected using inflation rates as described in my direct testimony above.

PART 3 – CORPORATE TECHNOLOGY PROJECTS

Q. Is the Company planning technology projects that support the Corporate Services functions?

A. Yes. Company witness Stacy H. Baker includes, in her direct testimony and exhibits, three technology projects that are critically important in enabling the Company's Corporate Services functions to support the Gas business in a safe, effective, efficient, and compliant manner. These projects are described below:

- The **Talent Management Enablement** project requires $164,456 in capital and $35,996 in O&M in the test year. The project will deliver technology solutions to enable Talent Management programs and processes that are critical to achieve the Company's overarching Talent Strategy Plan. The Talent Strategy Plan is a key enabler of the company's Integrated Resource Plan (IRP), Electric Distribution Infrastructure Investment Plan (EDIIP), and Natural Gas Delivery Plan (NGDP). Effective Talent Management programs and processes are critical to develop the skills, capabilities, productivity, and experience necessary to successfully execute these plans that deliver clean, reliable, affordable energy through an exceptional customer experience. Significant technology improvements are required to transform Human Resources (HR) to develop the skills and capabilities necessary to achieve the Company's strategic destination. Currently, many Talent Management processes are manually managed with little or no technology enablement. Specifically, the talent compensation processes are mostly manually done outside the system which introduces waste, and a potential for errors. In addition there is a limited visibility of competency gaps within the workforce. The Company cannot effectively place talent in accelerated development programs aligned to competency gaps, nor can it recognize and motivate employees for quickly increasing competency and performance. Furthermore, the Company operates in an increasingly competitive job market where candidates and employees expect best-in-class processes, technologies, and experiences relative to their employment and career development. The lack of full technical enablement across Talent Management programs poses a risk to employee attraction and retention, and limits the ability to develop the right skills at the right time to deliver on Company strategies. This project will add value to the Company through technology that will enable: (1) fully functional integrated compensation module; (2) accelerated and targeted talent development of critical skills necessary to deliver on the Company's commitment to clean energy and exceptional customer experience; (3) transparency into talent and skill gaps in order to identify retention and service delivery risks within critical areas, as well as inform succession and hiring strategies; (4) improved knowledge transfer, business continuity, and customer service during a time when retirement eligibility is high and risk of knowledge loss has the potential to negatively impact customer service and satisfaction; and (5) increased efficiency and quality of talent management through simplified and automated processes that reduce costs associated with recruiting, onboarding, and developing employees. Talent Management Enablement will deliver the best-practice technology to enable and enhance: (1) fully functional integrated talent compensation management; (2) simplified and automated talent management process for employee lifecycle management from on-boarding through off-boarding; (3) succession planning and business continuity; and (4) career development and employee retention. The scope will include: (1) implementation of each system/application; (2) integration with current systems, applications, and processes as applicable; (3) retrofit current systems and applications to ensure a seamless end-to-end experience of HR processes; (4) delivery of mobile capabilities for in scope processes; and (5) reporting and analytics dashboards and report insights for in scope processes. Three alternatives were considered for these Talent Management programs and processes: (1) Develop custom, internally built solutions that could meet most requirements. This alternative was not selected because a custom solution would result in higher overall costs, higher maintenance costs, fewer upgrades, and would not leverage industry best practices to ensure best-in-class delivery. (2) Select an on-premise software tool. This alternative was not selected because it requires internal maintenance, increases infrastructure costs, and would have less frequent upgrades which would hinder the Company's ability to ensure processes are evolving alongside industry trends and best practices. (3) Evaluate and select cloud/SaaS solution(s) which would have lower infrastructure costs, less internal maintenance than an on-premise solution, and would be built and evolved with upgrades based on industry best practices. Based on research, internal experience with successful best practice implementations, and vendor demonstrations, option three was selected.

- The **Expense Reporting Improvements** project requires \$134,162 in capital and \$38,961 in O&M in the test year. The Expense Reporting Improvements project will increase productivity when creating expense reports; leverage workflows for expense processing and exceptions; improve adherence to Company policies; provide insights through improved reporting; and minimize human intervention and struggle throughout the expense process. Multiple problems exist with our current expense reporting system in the areas of usability, employee engagement, inefficiencies, compliance, and audit exceptions. Submitting expense reports is not intuitive, leading to errors and the need for manual intervention. In addition, employees must manually scan and attach receipts. All these problems impact employees leading to poor employee engagement scores regarding simple processes, productivity, and transparency leading to increased costs, inefficiencies, exceptions to policies, and compliance issues. An average of 13% of all expense reports have compliance errors, based on a sample audit of executive assistant submitted expense reports. This project provides value for the Company by: (1) improving expense policy compliance and reducing exceptions, with a target measure of zero compliance errors; and (2) offering a more user-friendly experience leading to improved employee engagement. Completion of these objectives would enable each employee to save 20 minutes creating an expense report; considering the 50,175 expense reports created in 2021, the Company would have avoided approximately \$1.5 million in labor costs. The project scope includes implementing a new software tool that: (1) provides upfront validation and controls to improve policy compliance; (2) provides electronic document retention for receipts; and (3) integrates corporate credit card data into expense reports. Three alternatives were considered for the project: (1) continue using the current solution; (2) choose a cloud-based solution with the expense reporting component; and (3) develop a custom front-end. The first alternative would result in waste due to the system not being user-friendly; and does not provide mobile options. The second alternative would introduce new licensing and ongoing maintenance costs; would require periodic upgrades and testing; and would require the SAP Enterprise Portal to be upgraded to integrate with the booking tool. The third alternative and selected option would result in improved user experience and employee engagement as well as mobile capabilities around expense entry.

- The **Enterprise Risk Management** project requires $7,139 in O&M in the test year. The project will implement software to simplify processes pertaining to Enterprise Risk Management, improve efficiency, provide risk identification and repository tools, and provide real-time risk information. The Enterprise Risk Team (ERT) works with risk owners on an annual basis to identify new risks, update existing risks, document mitigation plans, and identify trends. This work is accomplished through an iterative back-and-forth process between ERT and risk owners. The intensive, time-consuming manual Enterprise Risk Management process creates risks of human error that can over or under quantify risks, introduce data anomalies, and create version tracking issues. The existing process results in substantial inefficient use of time by risk analysts and risk owners throughout the Company, limits the breadth of analysis that can be provided, and limits the overall ability of the Company to timely identify, analyze, and communicate risks to senior leaders, thereby causing potential delays in responding to emerging risks. Because of the lengthy manual process, it is only performed once a year, but must be performed more frequently to proactively manage enterprise risk. Utility industry peers leverage software to manage Enterprise Risk Management programs more effectively. This project creates value for the Company by: (1) providing real-time risk information to interested parties including the risk team, risk owners, senior management, and the Board of Directors supporting proactive risk management; (2) creating a centralized repository for risk identification, management, and mitigation plans; (3) eliminating waste by simplifying processes; and (4) improving efficiency of the risk owners and analysts. The scope of the project includes: (1) create risk analysis templates and tools for automated reporting; (2) configure automated workflow to perform risk updates; (3) configure dynamic templates that prompt the risk owners based on prior selections; (4) organize risk assessments through an online and searchable data capture (repository); (5) create new reports and executive dashboards; (6) data conversion; and (7) set record retention rules. Alternatives considered include: (1) Continue use of the current manual processes which result in waste, lack of quality results, and annual review of risks. (2) Build a custom internal enterprise risk solution. This option was not selected as it will not result in an enterprise risk program that leverages best practices that exist in software provided by the leaders in risk management software. (3) Implement a software solution from a leading enterprise risk solution vendor. While this would introduce new license and ongoing support costs, it is the preferred option because it leverages industry best practices with a proven solution; provides application reliability, security, and stability through ongoing vendor support; and brings innovation and insights via the reporting of risk information through management dashboards. In addition, it aligns the Company with utility industry peer practices for more effective enterprise risk management.

PART 4 – ACCOUNTING REQUESTS

Uncollectible Deferral/Refund Mechanism

Q. Does the implementation of the Uncollectible Deferral/Refund Mechanism, discussed in the Gas Uncollectible Expense testimony in Part 1, require any specific accounting approvals?

A. Yes. The Uncollectible Deferral/Refund Mechanism would result in deferred debits or credits until any under-recovery or over-recovery is fully collected or refunded. The Company requests approval to recognize regulatory assets or liabilities as needed to record these deferred amounts.

Q. Would any outstanding regulatory asset or liability associated with the Uncollectible Deferral/Refund Mechanism accrue interest?

A. No.

DB Pension/OPEB Volatility Mechanism

Q. Does the implementation of the DB Pension/OPEB Volatility Mechanism, discussed in Company witness Kendra K. Grob's direct testimony, require any specific accounting approvals?

A. Yes. The mechanism would result in deferred debits or credits until balances are fully amortized over 10 years. The Company requests approval to continue recognizing regulatory assets or liabilities as needed to record these deferred amounts as approved in the settlement agreement in Gas Rate Case No. U-21308.

PART 5 – AFFILIATED COMPANY TRANSACTIONS

Q. What is the purpose of your direct testimony with respect to Affiliated Company Transactions?

A. I am sponsoring Exhibits A-49 (MJF-6), A-50 (MJF-7), and A-51 (MJF-8) to comply with the filing requirements for gas rate cases before the Commission, as clarified in Case No. U-10039. I am also sponsoring two additional exhibits, Exhibits A-52 (MJF-9) and A-53 (MJF-10), as described below.

Q. Please explain Exhibit A-49 (MJF-6).

A. Page 1 of this exhibit provides an organizational chart showing the interrelationship of the affiliated companies that had transactions with Consumers Energy relative to providing/receiving services or commodities. In addition, pages 2 and 3 list their affiliation, percentage ownership, and purpose of business.

Q. Please explain Exhibit A-50 (MJF-7).

A. This exhibit summarizes costs billed to affiliated companies, page 1, and payments made to affiliated companies, page 2, for the year 2022.

Costs Billed to Affiliated Companies

Q. For the costs billed to affiliated companies, how are the costs classified and how are they priced?

A. These costs are classified as to whether they impact the balance sheet, other operating income, or utility operating income. These costs are all priced on a full-cost basis.

Q. What is meant by "costs are all priced on a full-cost basis"?

A. The full-cost basis means total direct costs along with applicable overheads. For services provided, it would be primarily labor costs incurred along with allocated overheads and employee benefits. For commodities purchased, it would be the contracted amount for the commodity based on a negotiated purchase by the Gas Supply organization or, on the electric side, the Electric Supply organization. Property leased is priced per contract.

Q. For commodity purchases, what is the difference between the full-cost amount and market amount?

A. At the time of the purchase, the full-cost amount and market amount would be the same. In other words, it is the agreed upon price between the purchaser and seller of the commodity.

Q. Please describe the types of services performed by Consumers Energy for affiliated companies.

A. Most services performed are administrative services such as payroll, corporate communications, human resources, and computer services; employee benefits related to health care, life insurance, and savings plan; or professional services such as engineering, accounting, legal, and tax.

Q. What types of billing activity are directly classified to the balance sheet?

A. These are the direct costs incurred for employee benefits or for rendering services to affiliated companies that are separately accounted for in Consumers Energy's accounting system and translate to an individualized receivable from the associated company (Account 146).

Q. What types of billing activity are classified as other operating income?

A. Billing activity classified as other operating income consists of income related to the cost of money.

Q. Please explain the cost of money.

A. The cost of money is the recovery of Consumers Energy's cost for the use of its funds expended to render services prior to reimbursement. This recovery is recorded in Account 419, Interest Income.

Q. What types of billing activity are classified as utility operating income?

A. Billing activity classified as utility operating income consists of overhead costs. These costs affect A&G expenses and revenue accounts.

Q. What is the impact of this utility operating income activity on gas operations?

A. As shown on Exhibit A-51 (MJF-8), gas operations were favorably impacted by $581,264.

Payments Made to Affiliated Companies

Q. Please describe the types of goods provided by affiliates and services performed for Consumers Energy as shown on Exhibit A-50 (MJF-7), page 2.

A. Services provided include officer services and professional services, such as accounting, engineering, finance, legal, energy purchases, and tax.

Q. For payments made to affiliated companies, how are they classified and how are they priced?

A. These payments are classified as to whether they impact the balance sheet, other operating income, or utility operating income. These payments are priced on a full-cost basis.

Q. What types of payment activity are classified as balance sheet items?

A. The payments classified as balance sheet items consist of costs deferred on the balance sheet for subsequent reclassification, amounts to be billed, or amounts recorded as liabilities.

Q. What types of payments are classified as utility and other operating income?

A. Payments consist generally of CMS Energy Corporation costs for restricted stock, energy purchases, and professional services.

Q. Is the Massachusetts Formula method used to allocate administrative costs of the parent company to Consumers Energy?

A. Yes. The Massachusetts Formula is used to allocate certain parent company indirect costs to its subsidiaries, which includes Consumers Energy.

Q. Why is the Massachusetts Formula method used to allocate costs?

A. This method is used to allocate indirect costs that cannot be readily identified to any particular subsidiary or affiliated company.

Q. How long has the Massachusetts Formula been used to allocate costs?

A. This allocation method has been used to allocate costs within CMS Energy Corporation since 1987.

Q. Are parent company costs that can be identified to Consumers Energy charged directly to Consumers Energy?

A. Yes. When the costs can be specifically attributed to Consumers Energy, these costs are charged directly to Consumers Energy.

Q. Why is the Massachusetts Formula method an appropriate allocation method for certain Company costs?

A. This method provides a practical means to allocate a pool of common costs based on an equitable and consistent basis. Subjectivity and inability to directly charge costs is the reason the Massachusetts Formula is utilized by entities to allocate costs.

Q. Did Consumers Energy develop the Massachusetts Formula?

A. No. It was first conceived as a method for state tax administration in Massachusetts. Subsequently, the formula was adopted for allocating A&G expense in diversified corporations.

Q. Has FERC approved the use of the Massachusetts Formula?

A. Yes. Examples of specific companies that have used this method include: Duke Energy, Entergy Services, Inc., San Diego Gas & Electric, and Williams Natural Gas Company.

Q. What is the impact of payments classified as utility operating income on gas operations?

A. The amount of payments applicable to gas operations for these activities in 2022 is $28,808 as shown on Exhibit A-52 (MJF-9).

Q. Please explain Exhibit A-53 (MJF-10).

A. This exhibit shows the rate of return on common equity for the affiliates doing business with Consumers Energy.

Q. Is Consumers Energy in compliance with the guidelines for intercompany transactions between affiliates as ordered by the Commission in Case No. U-18361?

A. To the best of my knowledge, Consumers Energy is in compliance with these guidelines.

Q. Does this conclude your direct testimony?

A. Yes.

S T A T E   O F   M I C H I G A N

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the application of **CONSUMERS ENERGY COMPANY** for authority to increase its rates for the distribution of natural gas and for other relief.	)))))	Case No. U-21490

DIRECT TESTIMONY

OF

MICHAEL P. GRIFFIN

ON BEHALF OF

CONSUMERS ENERGY COMPANY

December 2023

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 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

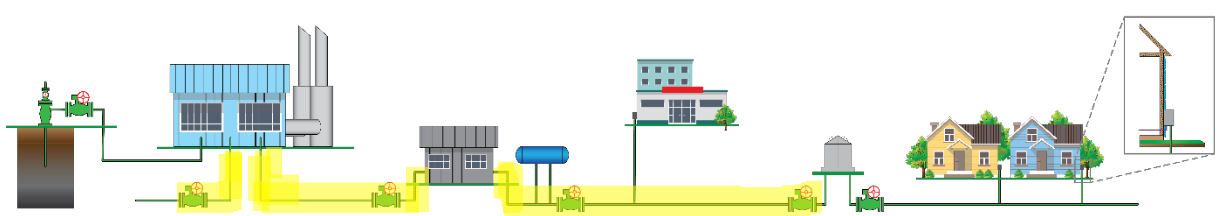
Electric Engineering, Operations, and Customer Operations departments. Since July 2021, I have held the role of Senior Strategy Manager for the Company's transmission assets.

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, and MPSC Case No. U-21308.

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-43 (NPD-1), sponsored by Company witness Neal P. Dreisig.



I have divided my direct testimony 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-55 (MPG -1)		Summary of Actual & Projected Regulatory Compliance O&M Expenses;
Exhibit A-12 (MPG-2)	Schedule B-5.5	Projected Capital Expenditures Transmission & Distribution Plant - Summary of Actual & Projected Gas Capital Expenditures;
Exhibit A-56 (MPG-3)		Actual & Projected Gas Transmission Capital Expenditures - Asset Relocation Transmission Program;
Exhibit A-57 (MPG-4)		Actual & Projected Gas Transmission Capital Expenditures – Regulatory Compliance Program;
Exhibit A-58 (MPG-5)		Actual & Projected Gas Transmission and Distribution Capital Expenditures - Capacity/Deliverability Program;
Exhibit A-59 (MPG-6)		Actual & Projected Gas Capital Expenditures - Transmission & Distribution Plant - TED-I Program Detail;
Exhibit A-60 (MPG-7)		Summary of Actual & Projected Gas Capital Expenditures - Transmission & Distribution Plant, Mid-Michigan Pipeline Project;
Exhibit A-61 (MPG-8)		2022 Monthly Capital Expenditures for TED-I Gas Pipeline Projects – Mid-Michigan Pipeline;
Exhibit A-62 (MPG-9)		2023 Monthly Capital Expenditures for TED-I Gas Pipeline Projects – Mid-Michigan Pipeline;

Exhibit A-63 (MPG-10)	2024 Monthly Capital Expenditures for TED-I Gas Pipeline Projects – Mid-Michigan Pipeline;
Exhibit A-64 (MPG-11)	2025 Monthly Capital Expenditures for TED-I Gas Pipeline Projects – Mid-Michigan Pipeline; and
Exhibit A-65 (MPG-12)	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-55 (MPG-1)?

A. Exhibit A-55 (MPG-1) shows the total O&M expenses for the Regulatory Compliance Program that I am sponsoring. I will further describe in my testimony the program expenses and projects contained within this program. As shown on line 5 of Exhibit A-55 (MPG-1), the O&M expenses I am sponsoring were $23,631,000 in 2022 and are projected to be $19,281,000 in 2023, $27,272,000 in 2024, and $27,796,000 for the 12 months ending September 30, 2025.

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. I will further describe in my testimony 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 $259,226,000 in 2022, and are projected to be $331,695,000 in 2023, $267,287,000 for the nine months ending September 30, 2024, and $224,678,000 for the 12 months ending September 30, 2025.

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 will move forward with the currently scheduled Transmission Enhancements for Deliverability & Integrity ("TED-I") projects and the re-build schedule for city gate facilities. This information can be found in Exhibit A-43 (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-43 (NPD-1), Section IV.D.5 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, 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 and Washtenaw Counties to relocate Line 1020 to accommodate plans for a new traffic pattern at the intersection of 8 Mile Road and Currie Road. Another example of the Company's continued coordination includes lowering segments of Line 1600 along Taft Road ahead of scheduled municipal road improvements planned by the City of Novi, in an effort to minimize disturbance and impact to the community. Furthermore, additional coordination in Saginaw County will allow 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 $7,901,000 in 2022, and are projected to be $5,081,000 in 2023; $14,821,000 for the nine months ending September 30, 2024; and $23,800,000 for the 12 months ending September 30, 2025.

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-56 (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. 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 the Asset Relocation Transmission Projects that Consumers Energy initiates, replacing and lowering pipeline segments in locations where grading or erosion has reduced cover to less than depths specified by 49 CFR 192.327(a) and Company standard requirements benefits 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 \$38,961,000 in 2022, and are projected to be \$31,051,000 in 2023, \$15,203,000 for the nine months ending September 30, 2024, and \$29,584,000 for the 12 months ending September 30, 2025.

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-55 (MPG-1).

A. As shown on Exhibit A-55 (MPG-1), line 5, the O&M expenses for this program were $23,631,000 in 2022, and are projected to be $19,281,000 in 2023, $27,272,000 for 2024, and $27,796,000 for the 12 months ending September 30, 2025.

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. The Code of Federal Regulations, 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 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. As indicated above, Consumers Energy developed a written TIMP in 2004. The 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. To minimize environmental and safety risks, Consumers Energy's TIMP delivers the following:

- Identify 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 plan;
- 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-43 (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 50 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.

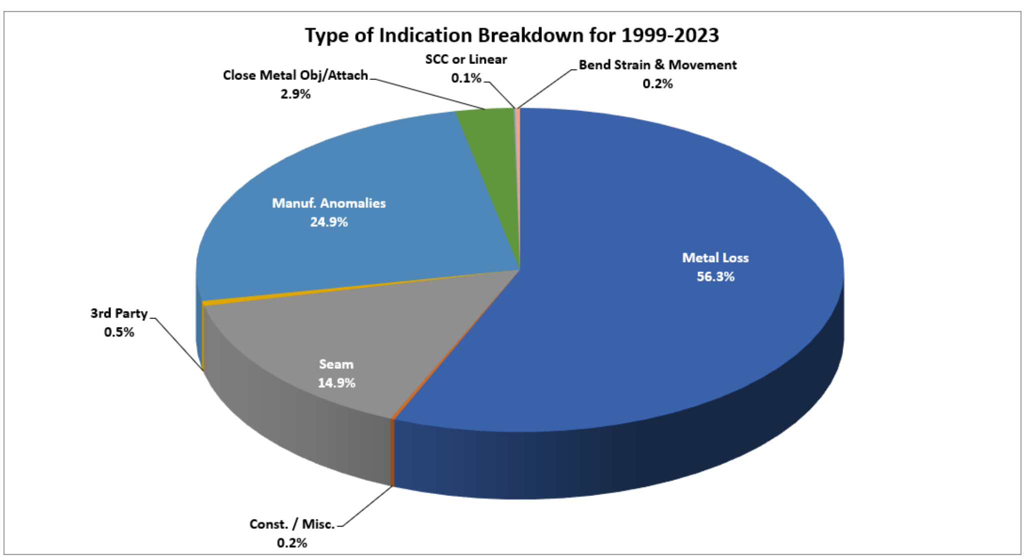
Exhibit A-43 (NPD-1), Section IV.C.1, provides additional information on these objectives.

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 2023 is shown in the Figure 1 below:

Figure 1

Type of Anomalies Found Through ILI Tool Runs 1999 through 2023



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 that are located in compressible soils to identify potential areas of high strain on its transmission pipelines. Since 2017, the Company has performed 43 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, and the Company is currently reviewing results and comparing them to previous relative risk model results. 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 in 2023.

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

A. As shown on Exhibit A-55 (MPG-1), line 4, the Company's Pipeline Integrity - Transmission O&M expense was $19,370,000 in 2022, and is projected to be $15,686,000 in 2023, $22,275,000 in 2024, and $22,584,000 for the test year ending September 30, 2025. The mileage the Company intends to inspect in 2022 through 2025 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			
2022	2023	2024	2025
66.8	258.1	466.6	278.6

Additionally, there are certain baseline assessments on longer pipeline segments that will lead to additional digs.

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-55 (MPG-1), line 3, the Company's Pipeline Integrity – TOD Program O&M expenses were $973,000 in 2022, and are projected to be $1,244,000 in 2023, $1,059,000 in 2024, and for the projected test year, the Company projects O&M expenses in the amount of $1,315,000. For pipe within HCA, the Company assessed 20.322 miles in 2022 and will assess 14.75 miles in 2023, 15.4 miles in 2024, and 22.8 miles in 2025. 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 will be performing ECDA assessments on non-HCA segments to reduce overall risk on TOD assets. This additional survey and assessment digs is why there is an increase in O&M expense between 2022 and 2023. 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-57 (MPG-4), line 1, the capital expenditures for this program were $9,798,000 in 2022, and are projected to be $10,509,000 in 2023, $5,859,000 for the nine months ending September 30, 2024, and $11,851,000 for the 12 months ending September 30, 2025, 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. 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-57 (MPG-4), line 2, the capital expenditures for this program were $21,736,000 in 2022, and are projected to be $9,495,000 in 2023, $4,583,000 for the nine months ending September 30, 2024, and $7,364,000 for the 12 months ending September 30, 2025, 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 1,292 UT sensors and 832 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 2022, the Company replaced pipe at the HCA in portions of Line 1022 and Line 1085. These replacements were performed to address prior overpressure events that may have affected the integrity of the longitudinal seams of these pipelines. In 2022, the Company conducted a pipe replacement project planned on Line 1002 f and g, and Line 1008 in Macomb County. The Line 1002 f and g replacement project is the replacement of the final section of pipeline that had sediment build-up in the pipeline. The replacement on Line 1008 is to replace a section of pipeline that is underneath the Clinton River, which makes this section of pipe unable to be assessed using Direct Assessment. The Line 1002 and Line 1008 pipe replacement projects are included in the Company's capital projections in the Pipeline Integrity – TOD Program. In 2023, new requirements ("RIN2") were implemented that increased requirements for ICDA assessments. These changes increased the number of excavations required.

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 $1,978,000 in 2022, and is projected to be $1,000,000 in 2023, $1,955,000 in 2024, and $2,069,000 for the test year ending September 30, 2025, as shown on Exhibit A-55 (MPG-1), line 2. O&M expenses for 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 time frame. 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.

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-57 (MPG-4), line 3, the capital expenditures for the Cathodic Compression, Storage, and Pipeline Capital Program were $6,814,000 in 2022, and are projected to be $5,772,000 in 2023, $4,283,000 for the nine months ending September 30, 2024, and $6,867,000 for the 12 months ending September 30, 2025, 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. In preparation for these additional requirements, the Company has increased monitoring and has identified projects as a result.

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 ("SEA") 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-57 (MPG-4), line 4, the capital expenditures for the MAOP Compliance Pipeline Capital Program were $612,000 in 2022, and are projected to be $5,276,000 in 2023, $478,000 for the nine months ending September 30, 2024, and $3,501,000 for the 12 months ending September 30, 2025. The projects in 2023 include the retirement and replacement of piping and valves on Line 1400 at Pontiac Trail VS, 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 and installation of piping and valves at the Mt Clemens City Gate on Line 1060. Capital projects planned for 2025 include replacement of valves and piping at Metamora City Gate on Line 1900, at Kern Road Valve Site on Line 2700, and at Blanchard Rd Valve Site on Line 100A. 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 SEA.

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-55 (MPG-1), line 1.

A. As shown on Exhibit A-55 (MPG-1), page 1, line 1, the O&M expenses for this program were $1,311,000 in 2022, and are projected to be $1,351,000 in 2023, $1,983,000 in 2024, and $1,828,000 in the test year 12 months ending September 30, 2025. The test year O&M expense comprises four parts.

The first part is an annual expense of $500,000 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 that must be completed due to a class location change. The necessity and nature of class location changes are described in the Deliverability Base Pipeline Capital Program later in my testimony. These projects are included in this O&M program because the length of pipeline replacement is less than 50 feet, which is the threshold for capitalization.

Third, there is a project involving the replacement of two short pipe segments to resolve an MAOP documentation gap.

The fourth part of the test year expense is due to expensing the O&M portion of the SEA costs. The SEA is more fully described above. 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 2022 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 2022, the Company expensed $712,697 for the 2019, 2020, and 2021 SEA expenditures. Table 2 below shows the SEA amounts expensed in 2022, and the SEA amount to be expensed in the test year.

Table 2

SEA Expensed in 2022 and the Test Year

Year	Direct Cost	O&M %	O&M Cost	
2019	408,998	27%	111,247	
2020	706,114	49%	348,114	
2021	870,570	29%	253,336	
Amount Expensed in 2022			**$ 712,697**	
Year	Direct Cost	O&M %	O&M Cost	
2022	1,323,792	56%	**$ 743,971**	**Test Year Amount**

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.

Table 3

Regulatory Compliance O&M Expenses by Project

Regulatory Compliance -MAOP Transmission O&M Expenses	2024	2025	12 Months Ending Sept 30, 2025
Aerial High Resolution Imagery Survey for Class Location Studies	$ 500,000	$ 500,000	$ 500,000
GL-03334 STC 1700 Huntcliff Village CLC Pipe Repl	$ 342,000		$ 253,413
GL-03335 STC 2070 Coolidge & Maple CLC Pipe Repl	$ 353,400		$ 261,861
GL-03345 SAG-L700-StLou Jxn Repl	$ -	$ 266,000	$ 68,901
Standardized Engineering Analysis Expense	$ 743,971		$ 743,971
Total MAOP Transmission O&M Expense	**$ 1,939,371**	**$ 766,000**	**$ 1,828,146**

Company witness Rayl discusses the reduction to rate base for the 2019 through 2022 amounts.

Q. Please explain page 2 of Exhibit A-55 (MPG-1).

A. Page 2 of Exhibit A-55 (MPG-1) presents an illustration of the amounts of the O&M expenses I am sponsoring by applying 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 in this manner.

III. <u>CAPACITY/DELIVERABILITY PROGRAM</u>

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 $212,364,000 in 2022, and are projected to be $295,562,000 in 2023, $237,263,000 for the nine months ending September 30, 2024, and $171,294,000 for the 12 months ending September 30, 2025. 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. <u>TED-I PROJECTS</u>

Q. Please explain the TED-I projects shown on Exhibit A-58 (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-58 (MPG-5), line 1, the capital expenditures for the TED-I Program were $82,475,000 in 2022, and are projected to be $203,703,000 in 2023, $145,364,000 for the nine months ending September 30, 2024, and $47,669,000 for the 12 months ending September 30, 2025. 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-43 (NPD-1), Section IV.C.1, 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.

Q. Please describe Exhibits A-60 (MPG-7) through A-64 (MPG-11).

A. These exhibits expand on and provide the project level expenditures for the Mid-Michigan Pipeline project. These exhibits also demonstrate the monthly capital expenditures for each construction project within the Mid-Michigan Pipeline project for the years 2022, 2023, 2024, and 2025. The expenditures are broken out by labor, capitalized engineering and supervision, materials, contractor, overheads, and other costs.

Q. Please describe the Mid-Michigan Pipeline project.

A. The Mid-Michigan Pipeline project replaces approximately 55 miles of Line 100A, between Ovid city gate in Clinton County and Chelsea Interchange in Washtenaw County. The project will address 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-59 (MPG-6), line 1, identifies the total capital expenditures for the Mid-Michigan Pipeline project. The capital expenditures for this project were $50,716,000 in 2022, and are projected to be $188,857,000 in 2023, $141,206,000 for the nine months ending September 30, 2024, and $37,533,000 for the 12 months ending September 30, 2025 (please see Table 4 with detailed expenditures by year). In 2022 through September 30, 2025, 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
2022	Pipe Delivery, Long Lead Material Procurement, Engineering, Environmental, Real Estate, Permitting, Freedom VS MAOP Upgrade, bypass line @ Chelsea valve site	n/a	$50,716 million (actual)
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	$188.857 million (full year projection)
2024	Pipeline Construction Phase 2, Restoration on Phase 1, Ovid city gate Rebuild, Engineering, Real Estate, Environmental, Permitting	Approx 25 miles	$171.940 million (full year projection)
2025	Restoration on Phase 2 and EGLE permitting requirements for wetlands & streams	n/a	$9,065 million (full year projection)

Major construction commenced in 2023 and will continue through 2024. Site restoration and environmental monitoring will continue beyond 2024. The project anticipates Phase 1 and Phase 2 construction costs to exceed the amounts projected in the last rate case due to inflation, very poor soil conditions, and excessive rain during construction season in 2023. Although the use of contingency costs is prudent practice in construction projects such as the Mid-Michigan Pipeline project, pursuant to prior Commission orders denying the Company's inclusion of contingency costs in its rate cases, the Company does not include project contingency costs in its projections for the Mid-Michigan Pipeline project., which are a prudent practice, in rate case filings.

Q. Why is 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 will replace 1949 vintage pipe that has demonstrated integrity issues that I will more fully describe below. In May 2015, this line experienced a rupture just north of Chelsea.

The project will also increase the capacity of the Company's natural gas transmission system. The increased capacity will provide 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 was the cause of the 2015 rupture?

A. Post-event analysis indicated the rupture was caused by near neutral pH SCC. This is a form of environmental cracking that requires specific conditions to develop. The rupture event did not result in ignition of the natural gas being transported, any injuries, or third-party property damage. SCC is further described above as part of the Pipeline Integrity Program.

Q. What events occurred following the 2015 rupture?

A. SCC conditions on Line 100A necessitated a pressure reduction between Freedom Compressor Station and Ovid Valve Site following the rupture and subsequent analysis. Because SCC caused the rupture, a hydro test of the Line 100A was required prior to returning the line to service. An EMAT inspection was performed prior to hydro testing to ensure pipeline integrity. EMAT is used to detect longitudinal surface-breaking cracks and related crack-like features. Following successful EMAT runs, remediation ensued in parallel to commencing hydro testing in sections. At the same time, a project was undertaken to ensure natural gas supply was not at risk by replacing a 6.3 mile section of 20-inch pipe from the Freedom Compressor Station to the Chelsea Valve Site in Washtenaw County.

Q. Has the transmission integrity management plan found other areas of concern on Line 100A?

A. Yes. In 2016, 16 locations were remediated based on ILI data, which found areas with characteristics similar to those that failed during the 2015 hydro test.

Q. Would Line 100A require additional hydro testing if this project is not completed?

A. Yes. Line 100A would require hydro testing every five years between the valve sections where the rupture occurred due to the SCC identified on the pipeline per the American Society of Mechanical Engineers, ASME B31.8S2004. Replacement of these segments will mean the hydrotest will not have to be done. The most recent hydro test was completed in 2020.

Q. Are there any integrity concerns regarding the pipeline coating?

A. Yes. Up to 72% of the pipe joints must be re-coated. Based on data from ILIs, 72% of the coating is fair to very poor, indicating that 13 to 42% of the surface area, including the joint, is disbonded. Corrosion rates under disbondment are usually higher than in soil due to the lack of cathodic protection. Additionally, disbondment at seams can create interactive threats.

Q. What is the significance of Line 100A in the natural gas transmission system?

A. Line 100A is one of a limited number of paths for gas entering from southern supply points traveling to customers and storage in the eastern and northern parts of the Company's transmission system.

Q. What advantages are realized by increasing the pipe diameter from 20 inches to 36 inches?

A. A larger size pipeline provides additional transmission capacity during the summer and winter. Additional summer capacity is needed to accommodate required maintenance outages on other major pipelines, in particular Line 2200. Line 2200 (36-inch pipeline between Chelsea and Fenton) is currently the primary path for natural gas moving from White Pigeon Compressor Station and Freedom Compressor Station to storage fields and customers in the east and north. By increasing the Mid-Michigan Pipeline to 36 inches, another primary path from southern supply points to storage will be available in addition to Line 2200. Scheduling outages on Line 2200 to avoid impacting supply capacity is challenging and is limited to short time windows. In the past, the Company has had to adjust and cancel outages on Line 2200 for system integrity and maintenance work as well as emergent work. Depending upon system conditions, an unplanned outage on Line 2200 could have a significant impact on supply capacity, which could prevent the Company from fully refilling storage in the summer or providing reliable supply to customers in the winter. The 36-inch Mid-Michigan Pipeline size would also offset impacts of other outages that can reduce system capacity.

Q. Were other alternatives evaluated to provide the additional transmission capacity?

A. Yes. Alternatives, including a looped option, were evaluated and determined to be more costly to customers and did not provide the additional system integrity improvements.

Q. Did the Company's Board of Directors approve the Mid-Michigan Pipeline project?

A. Yes, the project was approved by the Company's Board of Directors in January 2017, and was reviewed, based on the revised construction timeline, in August of 2019. The projected costs are still within the Board of Directors approved amount of $550 million.

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. Recognizing the significance of these devices, the Company has developed a comprehensive RCV installation plan as outlined in of the NGDP, Exhibit A-43 (NPD-1), Section IV.C.1.

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 cost 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 2022, the Company installed 42 RCVs and is projected to install 24 in 2023, 17 in 2024, and 17 in 2025. These installation numbers represent all RCVs installed in all programs and projects. Exhibit A-59 (MPG-6), line 3, identifies the total capital expenditures for RCVs not otherwise installed in other programs. The capital expenditures for these RCVs was $15,160,000 in 2022, and are projected to be $2,044,000 in 2023, $0 for the nine months ending September 30, 2024, and $5,890,000 for the 12 months ending September 30, 2025.

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 192.609 (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;" and 49 CFR 192.619. 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 2022, 2023 and 2024 projects include:

- Line 4060 Vector Hartland, Howell;
- Line 1200A CE-ANR Stag Lake, White Pigeon;
- Line 100B Ovid Valve Site, Ovid;
- Line 2700 Squirrel Rd Valve Site, Lake Orion; and
- Line 1100 Laingsburg Interchange, Laingsburg.

The installation of PLDs will improve the operation of the system and provide enhanced public safety. Exhibit A-59 (MPG-6), line 2, identifies the total capital expenditures for PLDs. The capital expenditures for PLDs were $15,385,000 in 2022, and are projected to be $12,235,000 in 2023, $3,149,000 for the nine months ending September 30, 2024, and $0 for the 12 months ending September 30, 2025. The PLD installation program is projected to be complete at the end of 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-59 (MPG-6), line 4, identifies the total capital expenditures for Pipeline & Other Installations/ Modifications. The capital expenditures for these expenditures were $1,214,000 in 2022 and are projected to be $567,000 in 2023; $1,009,000 for the nine months ending September 30, 2024; and $4,246,000 for the 12 months ending September 30, 2025.

Q. Please provide further information concerning the transmission interconnection 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 plan to file for an Act 9 certificate of necessity to construct and operate the interconnect by the end of the first quarter of 2024.

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-58 (MPG-5), line 3, identifies the total capital expenditures for the Deliverability Base Field Measurement Program. The capital expenditures for this program were $3,503,000 in 2022, and are projected to be $6,119,000 in 2023, $4,655,000 for the nine months ending September 30, 2024, and $11,040,000 for the 12 months ending September 30, 2025. 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. 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;
- Laingsburg LN 400 Meter Installation. Project year 2025; and
- Grand Blanc LN 400 Meter Installation. Project year 2025.

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-58 (MPG-5), line 4 identifies the total capital expenditures for the Deliverability Base Pipeline Program. The capital expenditures for this program were $31,712,000 in 2022, and are projected to be $24,142,000 in 2023, $18,538,000 for the nine months ending September 30, 2024, and $21,520,000 for the 12 months ending September 30, 2025.

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.

C. 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-58 (MPG-5), line 5, identifies the total capital expenditures for the Regulator Station Program. The capital expenditures for this program were $43,064,000 in 2022, and are projected to be $31,471,000 in 2023, $30,129,000 for the nine months ending September 30, 2024, and $39,384,000 for the 12 months ending September 30, 2025. The scope of the expenditures in this program is aimed at maintaining the integrity of 667 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.5 of the Company's NGDP, Exhibit A-43 (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 Supervisory Control and Data Acquisition ("SCADA") installations, 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. In 2020, the Company began to use a quantifiable risk ranking for City Gate and Regulator Station future planning of these investments as a factor for project selection. This ranking will take into account the variables the Company currently uses in project selection. The major projects in this filing include:

2022

- Southgate (Rebuild – Bay City);
- Blanchard (Rebuild - Blanchard);
- Bayport (Rebuild – Bayport);
- Manchester (Rebuild - Manchester);
- North Water & Atlantic (New Station – Bay City);
- Woodward & Nebraska (Rebuild – Royal Oak): and
- New Hudson Distribution Odorizer (Rebuild – New Hudson).

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 Distribution Odorizer (Rebuild – Plainwell).

2025

- Hill & Center (Rebuild – Grand Blanc);
- Poseyville (Rebuild – Midland);
- Center & Boltwood (Rebuild – Hastings);
- Hogsback & Pryor (Rebuild – Mason);
- Vienna and McKinley (Rebuild – Montrose Twp.);
- Silver Lake & Dixie (Rebuild – Waterford Twp.);
- Gardner & 7 Mile (Rebuild – Northville); and
- Central Odorant Operations Hub (Odorant storge facility – Mid-Michigan).

D. 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 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-58 (MPG-5), line 6, identifies the total capital expenditures for the T&S City Gate Program. The capital expenditures for this program were $51,629,000 in 2022, and are projected to be $29,781,000 in 2023, $38,577,000 for the nine months ending September 30, 2024, and $51,681,000 for the 12 months ending September 30, 2025. 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 can also be closed to restrict delivery as a mitigation if serious situations develop. The Company has developed a city gate work plan as outlined in Section IV.C.1 of the Company's NGDP, Exhibit A-43 (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. 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:

2022

- Greenfield City Gate (Rebuild – Royal Oak);
- Kalamazoo - Nazareth City Gate (Rebuild - Kalamazoo);
- Rochester City Gate (Rebuild – Rochester);
- Napoleon-Brooklyn (Rebuild – Brooklyn);
- Lansing – Airport City Gate (Partial Rebuild – Lansing);
- Bear Lake City Gate (Rebuild – Bear Lake);
- Goodison Emergency Shut-Down Valve (“ESD”) (Rochester); and
- Kalamazoo M Ave – Filter/Separator (“F/S”) (Oshtemo).

2023

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

2024

- Excelsior City Gate (Pipe install and CG Retirement - Excelsior);
- Orion City Gate (Rebuild - Lake Orion);
- Leonard-Lakeville City Gate (Rebuild – Leonard);
- Blissfield PEPL City Gate (Blissfield);

- Dorr City Gate (Modernization); and
- Jackson Park Rd ESD (Jackson).

2025

- Bancroft City Gate (Rebuild - Morrice);
- Lahser City Gate ESD (Beverly Hills);
- Flint Torrey City Gate;
- Laingsburg CG ESD Valve;
- Macomb CG ESD Valve;
- Hanover Horton CG;
- Jackson Hart PEPL CG; and
- Highland CG and odorizer.

E. MISCELLANEOUS TRANSMISSION AND COMPRESSION

Q. Please explain the Miscellaneous Transmission and Compression Expenditures shown on line 2 of Exhibit A-58 (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 2022 and 2023, the expenditures are for ROW expenditures offset by credits related to moving project costs from prior years to O&M.

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-65 (MPG-12).

A. Exhibit A-65 (MPG-12), 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-21308.

Q. Can you explain why columns (c), (d), (e), and (f) of Exhibit A-65 (MPG-12), do not contain any data?

A. Yes, the information for column (c), the "Last Rate Case Approved Spending Plan Case No. U-21308," cannot be provided because Case No. U-21308 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-21308, which was the 12 months ending September 30, 2024, this 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.

S T A T E O F M I C H I G A N

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the application of **CONSUMERS ENERGY COMPANY** for authority to increase its rates for the distribution of natural gas and for other relief.	)))))	Case No. U-21490

DIRECT TESTIMONY

OF

KENDRA K. GROB

ON BEHALF OF

CONSUMERS ENERGY COMPANY

December 2023

Q. Please state your name and business address.

A. My name is Kendra K. Grob, and my business address is One Energy Plaza, Jackson, Michigan 49201.

Q. By whom are you employed?

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

Q. What is your current position with Consumers Energy?

A. I am currently the Retirement Plans Manager.

Q. What are your responsibilities as Retirement Plans Manager?

A. I am responsible for design, implementation, and administration of the Company's retirement plans and our department has responsibility for the benefit plans for employees and retirees. In the retirement benefits area, the Company contributes to the cost of the Pension Plans, the Defined Company Contribution Plan ("DCCP"), and the 401(k) Employees' Savings Plan ("ESP"). My responsibilities for these benefit plans include the design, review, and administration of competitive, cost-effective, quality plans that will attract and retain qualified employees to serve customers. The purpose of these plans is to provide a portion of an employee's retirement income along with the employee's social security benefits and personal savings.

In the benefits area, the Company contributes to the cost of these benefits plans – health care (medical/prescription drug/dental including Health Savings Accounts ("HSAs") and Health Care Flexible Spending Accounts ("HCFSAs"), life insurance, and Long-Term Disability ("LTD") insurance. Like the retirement plans, our department also has responsibilities for these health care and other benefit plans to include the design, review, and administration of competitive, cost-effective, quality plans for employees and retirees of the Company that help attract and retain qualified employees to serve customers. In addition to these plans, the Company has the responsibility for several additional benefit plans offered to employees by the Company at group discounted rates, which require the employee to pay the full cost of the coverage elected. These voluntary plans include accidental death and dismemberment insurance, health care and dependent care flexible spending accounts, vision insurance, and dependent term life insurance. These insurance benefit plans also help attract and retain qualified employees to serve customers as these plans help protect employees and their families from significant financial loss in a number of areas. Our team is also responsible for Absence Management, Workers' Compensation, and Occupational Health programs, as well as the total well-being program, Live Well 365, which motivates employees to manage their entire well-being.

Q. What is your formal educational experience?

A. In 1998, I graduated from Siena Heights University in Adrian, MI with a Bachelor of Business Administration degree. I hold a Professional certification in Human Resources from HR Certificate Institute ("HRCI") and the Society of Human Resource Management ("SHRM").

Q. Would you please describe your previous work experience?

A. In 1995, I began my career focused on human resources at Health Care Solutions, Inc. as a Human Resources Manager. In this role I was responsible for the Human Resource Management of the corporate office in Ann Arbor, MI. Also, I had leadership responsibility over all field Human Resource Managers. In addition to this responsibility, I managed all health care and retirement plans for the company. It was my sole responsibility to ensure employees were enrolled in the correct plans and provide any administration to the plan. This also included plan audits and decision making in determining the best vendors.

In 2007, I began working for Amcor Rigid Packaging as a Senior Benefits Specialist. My area of responsibility was retirement plans, disability, and life insurance plans. In this role, I was responsible for the relationship with vendors and the administration of plans for our employees. I was the primary vendor contact for these areas and was heavily involved in all Request for Proposal processes in choosing vendors. While in this position, I sat on the Retirement Committee as the Secretary and took part in plan design and fund selections for both the pension and the savings plan.

In 2020, I joined Consumers Energy as Manager, Retirement Plans. My responsibilities include complete oversight for the Company pension and savings plans (401k). In this role, I ensure the Company provides retirement benefits to active and retired employees while maintaining accurate legal compliance with the Internal Revenue Service.

Q. Are you a member of any professional societies or trade associations?

A. I am professionally certified as a Human Resources Professional through both SHRM and the HRCI.

Q. What is the purpose of your direct testimony?

A. The purpose of my direct testimony is to provide support for the Company's costs related to the gas business portion of retirement, health care, life insurance, LTD plans, and other benefits provided to its employees and retirees. In Part I of my direct testimony, I will address the retirement benefits plans. In Part II of my direct testimony, I will address health care, life insurance, LTD plans, and other benefits, which include absence management and educational assistance programs.

Q. Are you sponsoring any exhibits?

A. Yes, I am sponsoring the following exhibits:

Exhibit A-66 (KKG-1)	Summary of Actual and Projected Benefits O&M Expenses for the Year 2022 and Test Year Ending September 30, 2025;
Exhibit A-67 (KKG-2)	CMS Energy – Pension Plans A and B - ASC 715 Pension Expense Estimates ($ millions);
Exhibit A-68 (KKG-3)	CMS Energy - ASC 715 OPEB Expense Estimates ($ millions); and
Confidential Exhibit A-69 (KKG-4)	CMS Energy – Actuarial Letter of Support for 2023 Year Projections.

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

A. Yes.

Q. Please describe Exhibit A-66 (KKG-1).

A. Exhibit A-66 (KKG-1), page 1, summarizes actual year 2022 and projected test year 12 months ending September 30, 2025, gas Operating and Maintenance ("O&M") expenses for the Company's retirement and insurance benefit plans offered to employees and retirees. On this exhibit, column (a) provides a program description of the O&M expense category. Column (b) provides the actual expense in 2022 for each plan. Column (c) provides the projected expense for the 12 months ending September 30, 2025. Page 2 provides information on inflation factor projections and adjustments using the methods discussed in this testimony and included in column (i). Column (j) is the projected test year O&M and is the sum of columns (b) + (d) + (f) + (h) + (i).

Q. Please describe Exhibits A-67 (KKG-2) and A-68 (KKG-3) and Confidential Exhibit A-69 (KKG-4).

A. Exhibits A-67 (KKG-2) and A-68 (KKG-3) provide the Aon actuarial projections for Pension and Other Post-Employment Benefits ("OPEB") expenses for the years identified. Both the Pension and OPEB projections in these exhibits provided by the Aon actuaries are from the year-end 2022 measurement of the Pension and OPEB plans and with current market conditions as of December 31, 2022. A letter from the actuary regarding the accuracy and completeness of the projections is included in Confidential Exhibit A-69 (KKG-4).

I. <u>RETIREMENT BENEFITS PLANS</u>

Q. Which retirement benefits are you addressing in this section of your direct testimony?

A. I am addressing the Pension Plans, DCCP, and ESP. These expenses are shown on Exhibit A-66 (KKG-1), page 1, lines 1 through 3.

Q. How are the Pension Plans, DCCP, and ESP expenses that are common to electric and gas operations allocated to the gas portion of the business?

A. Expenses common to both the electric and gas operations associated with the Pension Plans, DCCP, and ESP are allocated based on the relationship of employee labor dollars charged to gas operations compared to the labor dollars charged in both electric and gas operations. These allocations are made by the Accounting Department. The gas portion of the O&M expense for these plans is shown on Exhibit A-66 (KKG-1), page 1.

<u>Pension Plans</u>

Q. Would you please explain your Exhibit A-66 (KKG-1), line 1, which begins with ($21,515,000) in 2022?

A. Exhibit A-66 (KKG-1), page 1, line 1, shows the actual 2022 pension expense and the projected expense for 12 months ending September 30, 2025 attributable to the gas portion of the utility operations.

Q. How does the Company determine its expense for the Pension Plans?

A. The pension expense is determined using actuarial analysis that is performed in accordance with Accounting Standards Codification ("ASC") 715. Consumers Energy follows Generally Accepted Accounting Principles ("GAAP") for its financial statements. Under the provisions of GAAP, ASC 715 describes the methodology and assumptions required to properly calculate and account for pension expense which includes evaluation of market conditions at each of the Pension Plan's measurement dates. In addition, the process is rigorously reviewed by the Company's auditor to ensure compliance with GAAP and ASC 715.

ASC 715 requires an annual determination of pension expense. Pension expense is determined based on actuarially reviewed employee census data, plan provisions, plan assets, and certain other assumptions. Year-end disclosure information is also produced, based on these accounting standards, to show a reconciliation of plan assets and liabilities at the end of the Company's fiscal year. For this gas rate case, the Pension Plans were measured in January for year-end December 31, 2022.

Q. What are the components of the annual pension expense under ASC 715?

A. There are four components of the annual pension expense: (i) service cost; (ii) interest cost; (iii) expected return on plan assets; and (iv) amortization of gains or losses, prior service costs or credits, and any transitional amounts. The plan's service cost represents the value of the benefits earned during the year. This is determined individually for each participant based on their specific employee demographics. The interest cost represents interest on the plan's liabilities due to the passage of time. There is also an assumption made for the expected return on plan assets. The expected return on plan assets each year reduces the plan's annual expense. The expected return assumption is reviewed periodically by the plan's actuary, the plan's investment advisor, and the Company, and is intended to be a long-term assumption based on the best estimate of the long-term expected investment earnings of the plan assets. The last component of plan expense is amortization of various plan experiences that were not anticipated by the plan's actuarial assumptions. For example, plan experience gains or losses and plan design changes that would be amortized are included as a part of this component of plan expense. The amortization can be either credits or costs.

To calculate the plan's total pension benefit obligation and annual ASC 715 expense, the actuary uses a number of assumptions including discount rate, mortality table, salary change, expected return on plan assets, and expected future contributions needed to avoid benefit restrictions under the Pension Protection Act. The methods used to set assumptions are generally unchanged annually, while the values of each assumption are determined by the Company each year and reviewed by the Company's auditors and actuary.

Q. Please describe how the discount rate is set each year.

A. The Company relies on its actuary's discount rate setting model. The model uses current high-quality bonds to match the Pension Plan's cash flows using statistical techniques that create a yield curve that determines the effective discount rate for all maturities of pension payments. The model itself does not change annually, but the discount rate typically will be updated based on the most current market conditions.

Q. Please describe how the expected return on plan assets is set each year.

A. The Company uses future expected capital market assumptions, asset allocation information, and other resources provided by its consultants, which may include survey data and analysis of the Pension Plan's asset allocation. The expected return assumption is based on long-term expectations and not short-term returns. The Company uses all this information to establish an expected return on plan assets assumption that best estimates its expectation. While this assumption is reviewed for each plan measurement, it may or may not be updated annually depending on the information that is presented.

Q. Does the Company apply Accounting Standard Update ("ASU") No. 2017-07 Improving the Presentation of Net Periodic Pension/OPEB Costs Standard in this case?

A. Yes, the Company adopted the ASU No. 2017-07 standard as of January 1, 2017 and has applied the Standard in this case for both Pension and OPEB. This ASU No. 2017-07 standard allows only the service cost component of expense to be recorded as an operating expense and all other benefit cost components are to be recorded outside operating income. The Standard also allows only service costs to be capitalized, while all other cost components are recorded to net income immediately.

Q. Please describe the development of the Pension Plans expense shown on Exhibit A-66 (KKG-1), page 1, line 1, which begins with ($21,515,000) for 2022.

A. Each of the annual pension expense levels shown on Exhibit A-66 (KKG-1), page 1, line 1, for the gas utility is based upon Aon's actuarial determination of each plan's total expense for that year in accordance with ASC 715 and includes plan administration fees, aggregated for total pension expense. The Consumers Energy pension expense determined by Aon plus administration fees are allocated to the electric and gas portions of the utility using the Accounting Department methodology described earlier. This allocation resulted in the actual gas utility O&M expense for Pension of ($21,515,000) in 2022, and projected expense of ($29,581,000) for the 12 months ending September 30, 2025. The Exhibit A-66 (KKG-1), page 2, line 1, column (i), adjustment represents the Aon actual calculation of expense compared to the inflation factor.

Q. Have there been any significant changes to the Pension Plan structure in recent years?

A. Yes. The Company split its Pension Plan into two plans as of January 1, 2018. Generally, all participants who were employees of the Company on August 1, 2017 were included in Pension Plan A. All other participants, including any Cash Balance participants, were assigned to Pension Plan B. No changes to participant benefits occurred as a result of this change. The Company decided to make this change to help manage expenses of the Pension Plans by extending the amortization period for the inactive group and enabling the mitigation of Pension Benefit Guarantee Corporation premium variability.

Q. Did the Company make any cash contributions to the Pension Plans in 2022?

A. No, the Company to not contribute to either plan in 2022.

Q. Will the Company make any cash contributions to the Pension Plans in 2023 or 2024?

A. No cash Pension Plan contributions are required in 2023 or 2024 to avoid benefit restrictions. Any contributions the Company elects to make during these periods of time will depend upon future decisions of the Company regarding funding policy, the future value of plan assets and liabilities, and any potential legislative guidance or changes.

Q. Why did the pension expense decrease for the projected test year from 2022?

A. The Pension expense decreased due to higher discount rates and asset smoothing.

Q. Have any changes recently been made to Pension Plans benefits?

A. No significant benefit changes have been made to the Pension Plans since September 1, 2005 when the Pension Plans were closed to new hires and the DCCP was implemented for new hires. Increases in pension expense created by the assumption changes are moderated by the closure of the Pension Plans to new hires as of September 1, 2005. In addition, pension liabilities and expenses are moderating overall as many participants are retiring or leaving and commencing their benefits, which reduces the liability and associated expense over time. Liability and expense will continue to diminish (presuming no significant change in the market or discount rates) until there are no longer any employees or retirees covered by the defined benefit ("DB") Pension Plans.

Effective November 1, 2020, the Company changed the unreduced early retirement from age 62 to age 61 for the Company's pension union eligible employees. This benefit enhancement allows for the Company to continue to retain current union pension eligible employees since they can now retire one year earlier but not lose any percentage of their pension benefit and was very well received. The additional changes in the projected pension expense estimates from 2022, 2023, 2024, and 12 months ending September 30, 2025 are primarily the result of economic conditions external to the Pension Plans over which the Company has no control.

<u>**DB Pension/OPEB Volatility Mechanism**</u>

Q. Please describe the DB Pension/OPEB Volatility Mechanism that the Company is proposing?

A. The Company requests the ability to continue its implementation of a DB Pension/OPEB Volatility Mechanism that the Company was authorized to implement in the Michigan Public Service Commission's order approving the settlement agreement in Case No. U-21308. The sensitivity of DB Pension/OPEB expenses to changes in asset returns or other assumptions creates a significant potential for large variability in future expenses. Customers would benefit from a mechanism that eliminates the risk of future volatility in expense. This mechanism would allow the Company to defer annually the difference between the DB Pension/OPEB expense included in rates versus the actual annual DB Pension/OPEB expense recorded by the Company pursuant to ASC 715. If actual annual DB Pension/OPEB expense is less than the expense approved in rates, the Company proposes that this difference would be recognized as a regulatory liability and be amortized over 10 years starting the following January. Similarly, if actual annual DB Pension/OPEB expense is greater than the expense approved in rates, the Company proposes that this difference would be recognized as a regulatory asset and be amortized in the same manner. Any amortization of these regulatory assets or liabilities would be included in future general rate cases.

DCCP

Q. Does the Company provide an alternative qualified benefit plan to the closed Pension Plans for employees hired on and after September 1, 2005?

A. Yes. In order to remain competitive in the area of a benefits package that attracts and retains qualified and talented employees for the benefit of the customer, the Company replaced the Final Average Pay and Cash Balance versions of the qualified DB Pension Plan with the qualified DCCP for all existing Cash Balance participants and newly hired employees on and after September 1, 2005.

Q. Are there any employees included in the DCCP that were hired before September 1, 2005?

A. Yes. Those employees who were hired between July 1, 2003 and August 31, 2005 and were provided coverage under the Cash Balance version of the DB Pension Plan became participants in the DCCP as of September 1, 2005. As of September 1, 2005, for this specific group of employees, additional pay credits under the Cash Balance version of the DB Pension Plan were discontinued.

Q. Will the Cash Balance version of the DB Pension Plan accept any new employees as participants?

A. No. As with the Final Average Pay DB Pension Plan, the Cash Balance version of the DB Pension Plan now has a finite group of participants that, over time, will diminish until there are no longer any employees or retirees covered under this plan.

Q. Please provide a general description of the DCCP.

A. The DCCP currently provides an employer funded cash contribution of the employee's base pay to the ESP. No employee contribution is required to receive the employer contribution. All existing Cash Balance Plan employee participants and employees hired on and after September 1, 2005 participate in the DCCP as part of their retirement benefit package.

Q. Have any recent changes been made to the DCCP?

A. Effective January 2021 for the Company's union employees, the DCCP provides an 8% to 10% (previously 5% to 7%) employer funded cash contribution based upon the union employee's service time with the Company. New union hires receive an 8% contribution, which increases to 9% when they have six years of service with the Company. When union employees reach 12 years of service, they receive a 10% employer contribution. This service-based contribution approach for the DCCP serves as a talent retention mechanism. The increase in the union DCCP contributions was needed for the Company to remain competitive to attract qualified employees and retain talent that maximizes the efficiency of the Company's labor force and reduces costly turnover. Retaining trained, experienced, and motivated employees provides better service for customers.

The Company's exempt and non-exempt employees will continue to receive the DCCP which was effective in January 2016. The DCCP provides a 5% to 7% (previously 6%) employer funded cash contribution based upon the employee's service time with the Company. New hires receive a 5% contribution, which increases to 6% when they have six years of service with the Company. Employees receiving a 6% contribution before January 1, 2016 continue to receive their 6% employer contribution. When employees reach 12 years of service, they receive a 7% employer contribution. This service-based contribution approach for the DCCP serves as a talent retention mechanism and helps contain the cost of the DCCP for the benefit of the customer as all new hires starting in 2016 began receiving a 5% (previously 6% for new hires) employer contribution.

Q. Would you please explain your Exhibit A-66 (KKG-1), page 1, line 2, which begins with $7,509,000 in 2022?

A. Exhibit A-66 (KKG-1), page 1, line 2, represents the gas operations O&M expense related to the DCCP. The actual gas operations expense for this plan in 2022 was $7,509,000 as shown in column (b). Column (c) shows the projected gas DCCP expense of $8,281,000 for the 12 months ending September 30, 2025. DCCP costs are projected to increase using inflation factors of 4.2% for 2023, 2.7% for 2024, and 2.4% for 2025. If a DB Pension individual retires, the new person hired to replace their role is entered into the DCCP plan. Projected years 2023 thru 2025 used 60% electric and 40% gas split and 60% capital on gas expenses.

Q. As a result of the revised eligibility requirements for participation in the Final Average Pay DB Pension Plan or the Cash Balance version of the DB Pension Plan, is it correct to say that all new hire employees starting with September 1, 2005 and after will receive their retirement benefits through plans that are referred to as defined contribution type plans?

A. Yes. The primary plans that will provide monetary benefits to this group of employees upon retirement are the DCCP and the ESP.

<u>ESP</u>

Q. Please explain briefly the ESP.

A. The ESP is a defined contribution retirement savings program funded by employee and employer contributions. A portion of employee contributions is matched by Consumers

Energy. Prior to January 2022, the Company matched 100% of the employee's first 3% in contributions and 50% of the employee's next 2% in contributions to the ESP. Employee contributions beyond 5% were not matched by the Company. Consumers Energy's expense includes the Company's matching contributions and the payments made to Fidelity Investments for administration of the program.

Q. Have any recent changes been made to the ESP?

A. Effective in January 2022, the Company match design has changed only for Salaried (exempt and non-exempt) employees to 100% of employee contributions of up to 6% of the employee's salary. Employee contributions beyond 6% will not be matched by the Company. This change will help to keep the ESP cost and talent retention competitive in the market for the benefit of customers. The Union employees will continue receiving matching contributions of 100% for employee contributions of up to 3% of the employee's salary, and then 50% of employee contributions of up to the next 2% of the employee's salary.

Q. Would you please explain your Exhibit A-66 (KKG-1), page 1, line 3, which begins with $6,908,000 in 2022?

A. Exhibit A-66 (KKG-1), page 1, line 3, represents the Company's gas operations expense related to the ESP. In 2022, the actual gas utility O&M expense for the ESP was $6,908,000. For 2025, the gas utility O&M expense projected for the ESP's 12 months ending September 30, 2025, is $7,621,000. Savings Plan costs are projected to increase using inflation factors of 4.2% for 2023, 2.7% for 2024, and 2.4% for 2025. Projected years 2023 through 2025 used 60% electric and 40% gas split and 60% capital on gas expenses.

Q. Is the ESP employer matching program important to attracting and retaining employees?

A. Yes.

Q. Please explain why the ESP employer matching program is important to attract and retain employees.

A. The ESP with a match is commonly available from Michigan employers as well as from other utility company employers that Consumers Energy competes with for employee talent. It is necessary to continue providing this highly visible, competitive benefit to employees of Consumers Energy to continue attracting and retaining competent employees needed by the Company, particularly considering the large number of retirement eligible employees at the Company. Attracting qualified employees and retaining this talent maximizes the efficiency of the Company's labor force and reduces costly turnover. Retaining trained, experienced, and motivated employees works very much to the customers' benefit.

Q. Is the ESP employer match discretionary?

A. It is not discretionary for union employees. A provision in the Working Agreement ratified in 2005 with Operating Maintenance & Construction ("OM&C") and Virtual Call Center ("VCC") union employees assured these employees that the match would not be suspended during their five-year contract. This provision was renewed in the 2010 contracts as part of the final union agreements for these union groups, and it is also part of the Steelworker's union contract effective January 1, 2011. This provision was not changed in the most recent five-year contracts negotiated in 2020. This has been an important issue to the union during the last several labor negotiations, all of which were finally resolved through arms-length bargaining.

With respect to nonunion employees, there is not a similar contractual prohibition against suspension. However, the ESP employer match is part of an overall competitive benefits package and employees depend upon its continuation so they can accumulate savings for retirement. The Company's competitors continue to offer a savings plan match, and the Company plans to continue offering the match to compete for new talent and retain current talent for the benefit of the customer. As noted above, it is a benefit that helps the Company attract and retain qualified and talented employees. From a practical standpoint, the Company views the employer match as non-discretionary.

II. HEALTH CARE, LIFE INSURANCE, LTD PLANS, AND OTHER BENEFITS

Q. Which health care and insurance benefits are you addressing?

A. I am addressing active employee health care (including HSAs and HCFSAs), life insurance, LTD plans, and other benefits of absence management and educational assistance, as well as retiree health care and life insurance plans. These expenses are shown on Exhibit A-66 (KKG-1), page 1, lines 4 through 6.

Q. Are the expenses for active employee health care (including HSAs and HCFSAs), life insurance, and LTD benefits determined in the same way as expenses for retiree health care and life insurance benefits?

A. No. The expenses for active employees are based upon the actual costs for these benefits that are expected to be incurred. The expenses for retirees are determined using actuarial analysis, which is performed by the Company's actuary, in accordance with ASC 715, formerly known as Financial Accounting Standards ("FAS") 106.

Q. How were the portions of active employee and retiree health care (including HSAs and HCFSAs), life insurance, LTD, and other benefits costs allocated to gas O&M expense determined?

A. The portion of the Company's total program expenses attributable to the gas utility was allocated based upon an annual study by the Accounting Department of the relationship of the number of employees in the gas utility to the total number of employees in both the electric and gas utility. The amount allocated to the gas utility is allocated between O&M expense and capital expense based upon the Accounting Department's formula. Projected years 2023 thru 2025 used 56% electric and 44% gas split and 60% capital on gas expenses.

Active Health Care (Including HSAs and HCFSAs), Life Insurance, LTD, and Other Benefits

Q. Please describe the development of the active health care (including HSAs and HCFSAs), life insurance, and LTD expense levels that are shown on Exhibit A-66 (KKG-1), page 1, line 4, which begins with $15,984,000.

A. Exhibit A-66 (KKG-1), page 1, line 4, contains gas operations O&M expenses for the Company-funded benefit plans for active employees' health care (including HSAs and HCFSAs), life insurance, and LTD. The primary component of this expense is health care. Life insurance and LTD make up a much smaller portion of the expense. In 2022, the Company incurred an actual combined expense of $15,984,000 for health care, life insurance, and LTD for gas operations. The projected gas operation expense for these benefits for the 12 months ending September 30, 2025, is $17,747,000.

Q. What factors did you consider in projecting the Company's 12 months ending September 30, 2025 expenses for health care, life insurance, and LTD?

A. In projecting the 12 months ending September 30, 2025 health care expenses, a number of factors were considered. Primary factors included current and projected inflation factors and a review of 2022 and 2023 national health trends/costs survey information provided by Willis Towers Watson ("WTW") actuarial consulting. Additionally included were the Company's medical and prescription drug carrier's health cost and claims experience expectations, the continuing rapid rise in availability and price of specialty prescription drugs, the current employee headcount, and the continuing cost increase impacts of national health care reform.

Q. Please explain how these factors were used to determine the Company's expected health care costs.

A. The Company has determined that using the inflation factors in this case will keep cost increases in line with inflation amounts. The Exhibit A-66 (KKG-1), page 2, line 4, column (i) adjustment represents the annual rate of the inflation factor.

To further understand projected health care trends and costs, the Company and WTW reviewed expected health care trends and costs survey information from several large consulting firms.

The Company and WTW also reviewed the Company's actual health care claims experience for employees and retirees in its health plans - Blue Cross/Blue Shield of Michigan and Express Scripts. The Company's health plans indicate that the Company's workforce is older than the average in their plans, and, as a result, has a higher expected utilization rate of services that is associated with an older covered population. Of the

Company's current workforce on December 31, 2022, 45% of employees are over age 45; 31% are over age 50; and 16% are over age 55. The Company understands the older age of its workforce is expected to lead to higher health care expense (primarily due to utilization of services).

To project future health care expenses, the Company and WTW also considered all the plan changes and programs the Company has already implemented. These changes include sharing expected health care expense increases with employees through plan design changes, including increased deductibles, copayments, and out-of-pocket maximums; increasing employee premium contributions for coverage; adding telehealth benefits to medical plans to lower expense; educating employees regarding the prudent and informed use of health care benefits; promoting use of preventive benefit services; promoting well-being through Live Well 365, which is integrated into all medical plan designs, that encourages and rewards plan participants for taking steps toward healthier lifestyles; securing favorable pricing on prescription drugs obtained through a large employer prescription drug collaborative; negotiating lower administrative fees with health plans and promoting enrollment into the Consumer Directed Health Plan ("CDHP"), a high deductible health plan which currently provides a Company contribution to the participant's HSA.

The Company and WTW also considered the specific changes to the union employees' health care plan benefits as negotiated in its 2020 through 2025 contracts as well as changes made to the employees' health care benefit plans in 2021 described in detail later in this direct testimony. While there are very tangible savings in future health expenses to the Company and its customers as a result of these changes to employee health care benefit plans, the Company believes a portion of these savings will be offset by increased health expenses incurred under national health care reform requirements (like Patient Centered Outcomes Research Institute fees, employer mandate shared responsibility administrative/reporting requirements, and potential penalties) as well as increased prescription expenses due to the availability of new and expensive specialty prescription drugs in the market. In addition, while the Company has taken numerous steps to control the rising expense of health care, many of these changes are one-time events that lower a plan's expense in that year to establish a new baseline moving forward, but future health care expenses then continue to increase from the new baseline expense.

Q. What are some of the reasons that health care costs are increasing at a level higher than general inflation?

A. There are a number of factors causing a higher rate of health care inflation than is reflected in the general Consumer Price Indexes ("CPIs"). Health care costs are expected to continue rising during the next several years due to an aging population living longer, additional utilization of services, price increases for services, new medical technology, cost shifts from government plans, mandated benefits coverage, rising provider malpractice premiums, new taxes on health claims, and rapidly escalating prescription drug prices including high prices for new, expensive specialty drugs. In addition, national health care reform will increase Company health care costs in the near term as a result of eligibility expansions (e.g., adult children to age 26), mandated benefits, removal of annual dollar limits, additional taxes, fees, penalties, new compliance/reporting requirements, and more government shifting of costs through Medicare and Medicaid expansion. These factors are all outside the control of Consumers Energy. Even with all the employee and retiree health plan design and premium contribution changes made annually by the Company over a number of years, including the move to Live Well 365 program incentives, health care costs for the Company are still expected to continue increasing annually at a rate two to three times that of general CPI inflation. The assumption that health care costs will only increase at the general rate of inflation has not been the actual experience for many years and is not expected in the foreseeable future.

Q. Are increases in health care costs being experienced both locally and nationally?

A. Yes. While increases in health costs have moderated somewhat, both local and national health care costs continue to increase at rates greater than general CPI inflation.

Q. Are the significant increases in health care costs limited to active employees?

A. No. Health care costs are also increasing at a rate higher than the general CPI inflation for retirees for the same reasons cited earlier. In fact, retiree expenses are generally increasing at higher rates because of retirees' older ages and the resulting increases in utilization, particularly in the use of prescription drugs, including higher-priced specialty prescription drugs. The projected increases for active employee health care, like projected increases for retiree health care, are substantial, reasonably expected to occur, and largely beyond the control of the Company.

Q. Please describe the development of the expense levels for active employee life insurance and LTD costs included in Exhibit A-66 (KKG-1), page 1, line 4.

A. For 2023 and 2024, the Company used inflation factors of 4.2% and 2.7%. These expense estimates are reasonable as both life insurance and LTD premium costs are based on wage and salary levels and changes to this coverage throughout the year. The 4.2% and 2.7% annual increase represents the normal, expected merit increase in salaries/wages, increases due to salary adjustments made for job changes and promotions throughout the year, any upward movement in Company-paid life insurance coverage in each annual enrollment period, and increases in premium rates due to plan experience.

Q. What has the Company done to control the increase in active employee and retiree health care, life insurance, and LTD expenses?

A. The Company has aggressively managed these benefit costs for more than a decade. Significant changes have been made to all health care, life insurance, and LTD plans since the introduction of the Benefit by Choice program first implemented in 2002, which offered employees and retirees different levels of health, life, and LTD coverage. A summary of various changes made to manage the cost of the Company's health care plans offered to employees and retirees from 2002 through 2023 follows:

- Reduced the number of dental plan offerings by consolidating to one plan;
- Implemented additional specialty prescription savings programs to reduce member and Company costs;
- Reduced the number of healthcare plan offerings by eliminating two health maintenance organization ("HMO") plans;
- Joined prescription drug collaborative to improve efficiencies on pricing, customer service, and access to affordable prescription drug coverage;
- Streamlined all benefit plans to be 80% coverage levels;
- Offered telemedicine option for those seeking treatment for non-emergent conditions;
- Increased employee/retiree premium contribution levels annually;
- Implemented Preferred Provider Organization ("PPO") plans, providing discounted networks to all participants;
- Reduced PPO plan benefit coverage levels from 90%, 80%, and 70% to 85% and 70%;
- Reduced HMO plan benefit coverage levels from 100% to 90%;

- Increased employee/retiree PPO and HMO plan design cost sharing provisions including: medical/dental deductibles, out-of-pocket limits, office copays, urgent care copays, and emergency room copays on several occasions;
- Switched to Maintenance of Benefits ("MOB") coordination;
- Required covered spouse working full-time to have own employer coverage primary;
- Negotiated administrative fees and insured plan premium rates annually and bid the health plan market to improve pricing;
- Increased employee/retiree prescription drug benefit cost sharing through incentive four-tier plan designs, higher prescription drug copays and coinsurance, and use of an exclusive network for specialty drugs;
- Implemented prescription drug management programs including full-menu, dynamic-based coverage management programs, mandatory use of mail order, safety/efficiency provisions, and regular market bids for pricing through an employer collaborative;
- Implemented health and disease management programs and added case management;
- Implemented a Company-defined dollar contribution plan management approach;
- Eliminated duplicative, higher cost health plan offerings on several occasions;
- Introduced informed consumerism, cost information, and credible health resources;
- Used enhanced technology for more timely determination of plan eligibility and coverage;
- Implemented access-only retiree health care benefits for new hires (no Company subsidy);
- Implemented preventive benefits with no cost sharing, included the mandated changes required under the Affordable Care Act ("ACA");
- Implemented and promoted enrollment in a CDHP with an HSA;
- Increased premiums and out-of-pocket limits;
- In 2018, implemented new total well-being program called Live Well 365. This program allows employee/preMedicare retirees to be engaged in their total well-

being through a variety of well-being activities including, but not limited to, preventive exam, well-being assessment, physical challenges, and a variety of other activities available to increase year-round engagement. For those participants who complete level 1 of the Live Well 365 program, they remain in a higher benefit coverage level or receive an additional Company HSA contribution. Employees/preMedicare retirees that do not participate in Live Well 365 are moved to a higher out-of-pocket cost benefit coverage level or do not receive the second Company HSA contribution;

- Separated employee/retiree medical and dental plans to minimize reporting and compliance costs required by the ACA;
- Changed insured HMO plans to self-insured HMO plans;
- Implemented an ongoing medical/dental/vision plan dependent audit process to ensure only eligible employees, retirees, and their dependents are covered by these plans; and
- Secured improved prescription drug pricing and plan consulting services as part of membership in a large prescription drug employer prescription drug purchasing collaborative.

Q. What changes were made to the 2019 health care plans?

A. In 2019, deductibles and out-of-pocket limits increased for the HMO plans. The Company introduced a CDHP plan with no HSA seed from the Company. The employee share of health care plans also increased.

Q. What changes were made to the 2020 health care plans?

A. In 2020, the Company discontinued offering HMO plans for active employees. This change was due to declining enrollment and higher medical and prescription costs in the HMO plans. Active employees had the option to choose from three other high-quality PPO plans for 2020 coverage. The PPO plans offered an expanded network of providers both in and out-of-network. Active employees who elected the CDHP had the ability for saving options for current and future health care expenses through an HSA. The employee share of health care plans increased.

Q. What changes were made to the 2020 health care plans due to the COVID-19 pandemic?

A. The Company incorporated the following health care changes related to the COVID-19 pandemic. The coverage for COVID-19 Diagnostic Testing and Services required under Section 6001 of the Families First Coronavirus Response Act (the "FFCRA"), as amended by Section 3201 of the Coronavirus Aid, Relief, and Economic Security Act (the "CARES Act") and associated subsequently issued guidance (together, the "Diagnostic Coverage Mandate") required the Company to cover certain diagnostic and preventive services related to COVID-19 without imposing any cost-sharing requirements, requiring prior authorization, or imposing other medical management requirements. Effective March 18, 2020, the Company provided coverage in accordance with the applicable requirements of the Diagnostic Coverage Mandate through the duration of the public health emergency related to COVID-19 as declared by the Secretary of the United States Department of Health and Human Services.

Effective from March 18, 2020 through June 30, 2020, the Company had to provide coverage for treatment related to a diagnosis of COVID-19 at no cost (i.e., without cost sharing) to participants and their covered family members. Effective from March 18, 2020 through June 30, 2020, the Plan provided coverage for telehealth and online visits at no cost (i.e., without cost sharing) to Plan participants and their covered family members.

Q. What changes were made to the 2021 health care plans?

A. In response to the COVID-19 pandemic, the Company continued to offer coverage for COVID-19 diagnostic testing and services without imposing any cost-sharing requirements for employees and covered family members. The Company did not make any significant changes to the health care plans and employee premium contribution for health care. The Company continued to offer quality health care coverage for employees to ensure a healthy workforce to better serve customers.

Q. What changes were made in the 2022 health care plans?

A. In response to the COVID-19 pandemic, the Company continued to offer coverage for COVID-19 diagnostic testing and services without imposing any cost-sharing requirements for employees and covered family members. The Company did not make any significant changes to the health care plans and employee premium contribution for health care. The Company continued to offer quality health care coverage for employees to ensure a healthy workforce to better service customers.

Q. What changes were made to the 2023 health care plans?

A. In 2023, the Company added Domestic Partner Coverage to its Health Care Plans. This is an important benefit to offer employees as we continue to ensure our Benefits attract and retain a diverse workforce. The additional coverage will result in engaged employees and excellent service for customers. Also, the Company increased health care plan designs (deductible, out-of-pocket limits, and prescription copays) for the traditional PPO plan for both union and salaried coworkers. We increased health care premiums for the CDHP and eliminated one of the dental providers to improve overall dental costs. Lastly, the Company continued to utilize a cost-savings plan for certain Specialty Drugs through our prescription provider. Overall, the Company is continuously managing its health care vendors for cost efficiencies, implementing reasonable health care plan design and premium increases, and eliminating choice on the dental plans.

<u>Retiree Health Care and Life Insurance</u>

Q. Would you please explain your Exhibit A-66 (KKG-1), page 1, line 5, for retiree health care and life insurance, which begins with ($52,795,000) in 2022?

A. Exhibit A-66 (KKG-1), page 1, line 5, reflects the actual 2022 and projected 12 months ending September 30, 2025 gas utility retiree health care and life insurance expenses under ASC 715 (formerly known as FAS 106 expense). Each of the annual expense levels shown on line 5 is the total of two separate items which make up the total expense. Each year's expense contains an ASC 715 expense calculation and an actuarial services expense.

Q. How does the Company determine its ASC 715 expense for retiree health care and life insurance?

A. The expense is determined using actuarial analysis that is performed in accordance with ASC 715. Consumers Energy follows GAAP for its financial statements. Under the provisions of GAAP, ASC 715 describes the methodologies and assumptions required to properly calculate and account for retiree health care and life insurance expense which includes evaluation of market conditions at each of the plan's measurement dates. The calculations required by the accounting standards are performed at least annually by the plan's actuary, Aon, using information specific to the Company's OPEB plan. In addition, the process is rigorously reviewed by the Company's auditor to ensure compliance with GAAP and ASC 715.

ASC 715 requires an annual determination of retiree health care and life insurance expense (OPEB expense or formerly FAS 106 expense). The expense is determined based on actuarially reviewed employee census data, the plan provisions, plan assets, and certain other actuarial assumptions. Year-end disclosure information is also produced, based on these accounting standards, to provide a reconciliation of plan assets and liabilities at the end of the Company's fiscal year. For this gas rate case, OPEB was measured in January for the year-end 2022.

Q. What are the components of the annual ASC 715 retiree health care and life insurance expense?

A. There are four components of the annual ASC 715 retiree health care and life insurance expense: (i) service cost; (ii) interest cost; (iii) expected earnings on plan assets; and (iv) amortization of gains and losses, prior service costs or credits, and any transitional amounts. Service cost represents one year's expected benefits earned by active covered employees. Interest cost represents interest on the plan's benefit obligation (its liabilities) due to the passage of time. There is also an assumption made for the expected rate of return on plan assets. This rate of return assumption is intended to be a long-term assumption based upon the best estimate of long-term expected investment earnings of the plan assets. The last component represents amortization of various plan experiences that were not anticipated by the actuarial assumptions.

In order to calculate the plan's total benefit obligation and annual ASC 715 retiree health care and life insurance expense, the actuary uses a number of assumptions including health care inflation trend rates, mortality table, the rate of employee retirements from the Company, the actual retiree health care and life insurance claims of the Company, a discount rate, and the expected contributions to the plan. The methods used to set assumptions are generally consistent, while the values of each assumption are determined by the Company each year and reviewed by the Company's auditors and actuary. The method to set the discount rate and expected return on plan assets is the same as the method used for the pension plans, as discussed above.

Q. Are actuarial and administrative expenses included in Exhibit A-66 (KKG-1), page 1, line 5?

A. Yes. An annual expense for the actuarial and administrative services provided for the retiree health care and life insurance plans is included in Exhibit A-66 (KKG-1), page 1, line 5.

Q. What changes were made to the 2019 retiree health care plans?

A. The preMedicare retirees have the same health care plan options as the active union and nonunion employees. The Company partnered with an individual Medicare marketplace provider for specific Medicare eligible retirees to select their own coverage. The Company provided a Health Reimbursement Account ("HRA") to retirees based on years of service and hire date. The retirees worked with a benefits consultant to select the best quality and affordable health care coverage.

Q. What changes were made to the 2020 retiree health care plans?

A. The preMedicare retirees had the same health care plan options as the active union and nonunion employees. The preMedicare retirees no longer had the option to select the HMO plans. The preMedicare retirees had the same COVID-19 health care plan changes as the active union and nonunion employees. The Medicare eligible retirees who received a Company subsidized HRA received a 2% increase into their HRA. These retirees select their retiree health care coverage through an individual Medicare marketplace. The private Medicare marketplace specializes to assist retirees to select the best quality healthcare plan options at the most affordable price. The HRA subsidy amount was allotted based on years of service and hire date.

Q. What changes were made to the 2021 retiree health care plans?

A. The preMedicare retirees had the same health care plan options as the active union and nonunion employees. The preMedicare retirees no longer had the option to select the HMO plans. The preMedicare retirees had the same COVID-19 health care plan changes as the active union and nonunion employees. The Medicare eligible retirees who received a Company subsidized HRA received a 2% increase into their HRA. These retirees selected their retiree health care coverage through an individual Medicare marketplace discussed above. The HRA subsidy amount was allotted based on years of service and hire date.

Q. What changes were made to the 2022 retiree health care plans?

A. The preMedicare retirees had the same health care plan options as the active union and nonunion employees. The preMedicare retirees had the same COVID-19 health care plan changes as the active union and nonunion employees. The Medicare eligible retirees who receive a Company subsidized HRA received a 2% increase into their HRA. These retirees selected their retiree health care coverage through the individual Medicare marketplace discussed above. The HRA subsidy amount was allotted based on years of service and hire date.

Q. What changes were made to the 2023 retiree health care plans?

A. The preMedicare retirees have the same health care plan options as the active union and nonunion employees. The preMedicare retirees have the same COVID-19 health care plan changes as the active union and nonunion employees. The Medicare eligible retirees who receive a Company subsidized HRA will receive a 2% increase into their HRA. These retirees select their retiree health care coverage through an individual Medicare marketplace discussed above. The HRA subsidy amount is allotted based on years of service and hire date. Effective January 1, 2023, the Company is only offering a single dental plan, which allows for lower premiums and access to a wider provider network.

Q. Do the calculations for the retiree health care and life insurance expense follow the prescribed methodology of ASC 715?

A. Yes. The amounts are projected based on ASC 715 using information specific to the Company's retiree health care and life insurance plans. For this gas rate case, the OPEB Plan was measured in January 2023 for year end.

Q. Has the Company applied the ASU No. 2017-07 Improving the Presentation of Net Periodic Pension/OPEB Costs Standard in this case for OPEB?

A. Yes, the Company adopted the ASU No. 2017- as of January 1, 2017 and has applied the Standard in this case for both Pension and OPEB.

Q. Please describe the development of the retiree health care and life insurance expense levels that are shown on Exhibit A-66 (KKG-1), line 5, which begins with ($52,795,000) in 2022.

A. The O&M retiree health care and life insurance expense level shown on line 5 for the gas utility is based upon Aon's actuarial determination of the plan's expense for that period in accordance with ASC 715 plus the cost for actuarial and administrative services related to these plans. Due to the retiree medical plan changes described earlier, the actual 2022 O&M retiree health care and life insurance expense for the gas utility was ($52,795,000). The projected gas O&M retiree health care and life insurance expense is ($32,654,000) for the 12 months ending September 30, 2025. The Exhibit A-66 (KKG-1), page 2, line 5, column (i), adjustment represents Aon's calculation of expense compared to the inflation factor.

Q. Why is the retiree health care and life insurance expense lower in 2022 and increasing in the test year?

A. Year 2022 had lower-than-expected asset returns, which caused the higher projected expense in the test year.

Q. Would you please explain your Exhibit A-66 (KKG-1), page 1, line 6, for Other Benefits, which begins with $2,409,000 in 2022?

A. Exhibit A-66 (KKG-1), line 6, reflects the actual 2022 and projected 12 months ending September 30, 2025, gas utility benefits labor, the absence management program, the educational assistance program, the employee assistance program, and the Leaving It Better Award program The Exhibit A-66 (KKG-1), page 2, line 6, column (i), adjustment represents a reduction in headcount expense and the addition of the Leaving It Better Award program compared to the inflation factor.

Q. Please explain why the absence management program is important to attract and retain employees.

A. Paid sick leave is needed to attract and retain employees. In 2014, the Company retained Reed Group, an external consultant to manage the Company's absence process. Since the relationship's inception, Reed Group has been able to improve the absence rate and provide tracking information to the Company. The Company's absence rate decreased from 3.88% in 2014 to 3.63% in 2017. The reduction in absences results in lower labor costs. A benefit of the absence management program is clinical nurse case management. This provides resources for employees as they navigate through their illness. The nurse case management provides medical knowledge and assistance to employees. Additionally, this streamlined approach ensures a procedure for all employees who need a leave of absence for any purpose.

Q. Please explain why the educational assistance program is important to attract and retain employees.

A. Educational assistance programs are very much available from Michigan employers as well as from other utility company employers that Consumers Energy competes with for employee talent. A 2018 WTW benchmarking study indicates that 98.8% of 84 energy companies nationwide provide full (16.7%) or partial (82.1%) tuition reimbursement to their employees. The Company offers partial tuition reimbursement to all employees. It is necessary to continue providing this highly visible, competitive benefit to employees of Consumers Energy to continue attracting and retaining competent employees needed by the Company, particularly considering the large number of retirement eligible employees at the Company. Attracting qualified employees and retaining this talent maximizes the efficiency of the Company's labor force and reduces costly turnover. Retaining trained, experienced, and motivated employees works very much to the customers' benefit. Additionally, educational assistance provides the opportunity for employees to continue their education, which further improves their skills to serve the customers of the Company.

Q. Please explain why the employee assistance program is important to attract and retain employees.

A. The Company offers employees, retirees, and dependents access to an assistance program which provides support to help resolve or manage problems that interfere with the ability to perform at work or in life. The employee assistance program provides a variety of on-line tools, face-to-face interactions, and telephone support. The program is designed to aid with any type of need, distraction, concern, or crisis. The employee assistance program provides legal support, financial information, work-life solutions, online services, and confidential counseling. The goal of the program is to improve the overall total well-being for all the Company's employees and retirees.

Q. What is the Leaving it Better Award employee recognition program?

A. The Leaving it Better Award is used to recognize and reward regular salaried, exempt, and non-exempt employees who impact the Company's success by exhibiting the Company's vision and culture in a way that furthers the Company's goals, operational excellence, customer satisfaction, and corporate reputation. Leaders nominate employees and employees can receive a lump sum of up to $4,000.

Q. Please explain the benefits of the Leaving it Better Award?

A. This additional employee recognition is a way to show employees that they are valued for their work, increases the level of productivity at work, and reduces employee turnover, which supports improved service to customers. While the Company already provides merit pay increases for employee achievement of goals and objectives and accomplishment of tasks, duties, and responsibilities as set out in an employee's annual performance evaluations, the employee recognition in the form of a Leaving it Better Award provides additional recognition for going above and beyond the everyday expectations to serve the Company and its customers.

Q. Does this conclude your direct testimony?

A. Yes.

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the application of **CONSUMERS ENERGY COMPANY** for authority to increase its rates for the generation and distribution of natural gas and for other relief.	))))))	Case No. U-21490

DIRECT TESTIMONY

OF

QUENTIN A. GUINN

ON BEHALF OF

CONSUMERS ENERGY COMPANY

December 2023

Q. Please state your name and business address.

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

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

A. I am employed by Consumers Energy Company ("Consumers Energy" or the "Company") as Principal Metrics & Analytics Specialist.

Q. What are your responsibilities as Principal Metrics & Analytics Specialist for Consumers Energy?

A. As Principal Metrics & Analytics Specialist, I am responsible for providing support and direction for Facilities, Real Estate, and Administrative Operations strategy development, compliance, resource planning, and regulatory proceedings. The Facilities execution plan ranges from activities related to gas operations to those involving corporate operational areas of Consumers Energy. Facilities' asset portfolio consists of over 55 buildings and includes the corporate office, storerooms, distribution centers, maintenance garages, service centers, welding and fusion workshops, learning and development buildings, coal generation, wind generation, gas compression, and hydroelectric sites. My responsibilities include regulatory compliance, rate case strategy and execution, corporate policy administration, organizational vision, and resource planning for field execution.

Q. What is your formal educational experience?

A. I hold a bachelor's degree in economics from Yale University, located in New Haven, Connecticut, and a Juris Doctorate degree from Washington University, located in St. Louis, Missouri.

Q. Would you please describe your previous work experience?

A. In 1999, I started my career at Consumers Energy as a Contracts Analyst. In 2000, I began a series of changing roles, with increasing responsibility, from Contracts Supervisor to Director of Contract Services. In each successive role, I led teams of Contract Analysts and Contract Administrators who were responsible for a broad range of construction, maintenance, consulting, information technology, and engineering contracts. The responsibilities of these teams included sourcing and evaluating contractors and consultants, developing scopes of work, competitively bidding work, negotiating agreements, and administering contracts. In 2013, I began work in a series of successive roles focused on data, analytics, performance, and work management culminating in my current role as Principal Metrics & Analytics Specialist.

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

A. The purpose of my direct testimony is to support the Company's costs related to the Gas business portion of Facility Operations ("Facilities"). I will:

- Describe the Gas Operations Support function;
- Describe the methodology employed by Facilities for evaluating the health of its various facilities;
- Support the reasonableness and prudence of the capital expenditures for Asset Preservation for the historical year ended December 31, 2022, the bridge period beginning January 1, 2023, and ending September 30, 2024, and the projected test year ending September 30, 2025; and
- Support the reasonableness and prudence of the Operation and Maintenance ("O&M") expenses for Facilities, Real Estate, and Administrative Operations for the historical year ended December 31, 2022, the bridge period beginning January 1, 2023, and ending September 30, 2024, and the projected test year ending September 30, 2025.

Q. Have you previously testified in a Michigan Public Service Commission ("MPSC" or the "Commission") Rate Case?

A. Yes. I have provided testimony on behalf of Consumers Energy Company in Case Nos. U-21148, U-21224, U-21308, and U-21389.

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

A. Yes. I am sponsoring the following exhibits:

Exhibit A-12 (QAG-1)	Schedule B-5.6	Summary of Actual & Projected Capital Expenditures;
Exhibit A-70 (QAG-2)		Summary of Actual and Projected O&M Expenses;
Exhibit A-71 (QAG-3)		Detailed List of Projected Gas Capital Expenditures;
Exhibit A-72 (QAG-4)		Lansing Service Center – Plan Summary;
Exhibit A-73 (QAG-5)		Hastings Service Center – Plan Summary;
Exhibit A-74 (QAG-6)		Gas Construction – Plan Summary;
Exhibit A-75 (QAG-7)		Kalamazoo Service Center – Plan Summary;
Exhibit A-76 (QAG-8)		Parnall 1-3 Renovations – Plan Summary;
Exhibit A-77 (QAG-9)		Jackson Dispatch – Plan Summary; and
Exhibit A-78 (QAG-10)		New Construction & Renovations – Cost Detail.

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

A. Yes.

Q. Please describe the exhibits you are sponsoring.

A. Exhibit A-12 (QAG-1), Schedule B-5.6, details the actual and projected capital expenditures related to Gas Operations Support. Exhibit A-70 (QAG-2) details the O&M costs related to Gas Operations Support. Exhibit A-71 (QAG-3) identifies Gas Operations Support Programs and the projected capital expenditures related to those projects and programs. Exhibit A-72 (QAG-4) includes the existing Lansing Service Center Facility Health Assessment, conceptual plan for the New Lansing Service Center, various alternatives that were considered, customer drive time analysis, and building operating cost information. Exhibit A-73 (QAG-5) includes the existing Hastings Service Center Facility Health Assessment, conceptual plan for the New Hastings Service Center, various alternatives that were considered, customer drive time analysis, and building operating cost information. Exhibit A-74 (QAG-6) includes images and schedules for renovation of the leased facilities included in the Gas Construction Project. Exhibit A-75 (QAG-7) includes the existing Kalamazoo Service Center Facility Health Assessment, conceptual plan for the renovated Kalamazoo Service Center, various alternatives that were considered, customer drive time analysis, and building operating cost information. Exhibit A-76 (QAG-8) includes plans for the now substantially completed Parnall 1-3 Renovation Project. Exhibit A-77 (QAG-9) includes floor plans and conceptual design for the Jackson Dispatch Project. Exhibit A-78 (QAG-10) includes additional cost detail for various New Construction & Renovations projects.

Q. Please explain the Gas Operations Support function.

A. The Gas Operations Support function consists of the following support organizations: Fleet Services, Facilities, Real Estate, and Administrative Operations. Gas Operations Support acquires, constructs, and maintains fixed assets required to operate the functional areas of the business that serve the Company's customers.

Q. Are you addressing all support organizations related to Gas Operations Support in your direct testimony and exhibits?

A. No. Fleet Services will be addressed in the testimony of Company witness Adam S. Carveth.

Q. What is the function of the Facilities organization?

A. Within Gas Operations Support, Facilities manages, maintains, and operates 59 buildings comprising 3.2 million square feet of building space across the state of Michigan that allow the Company to serve customers across the state in an efficient and effective manner.

Q. How have Company facilities changed over time?

A. The Company experienced major growth in the area of Facilities during the 1950s and 1960s. Of its 59 buildings, nearly half were built or acquired during this period and remain in operation today. As a result, many of these buildings are now over 50 years old. The Company made no significant investment in its facilities and initiated no major renovations or construction of new buildings between 1970 and 2000. In 2003, the Company constructed its One Energy Plaza headquarters building in Jackson. This construction marked the adoption of the open office concept (i.e. fewer hard wall offices) at the Company which, among other reasons, was adopted to foster a more collaborative work environment. Between 2000 and 2016, the Company also closed many facilities including 22 service centers across Michigan to adapt to shifting population trends in the state and optimize service to customers.

Q. What structural concerns or problems do these aging structures and facilities create for the Company?

A. Multiple major systems throughout these facilities, such as boilers, chillers, cranes, elevators, emergency generators, heating, ventilation, and air conditioning ("HVAC") systems, lighting, power distribution, paving, roofing, Uninterruptible Power Systems, and vehicle hoists are beyond their useful lives. Further, building materials in the facilities contain hazards such as asbestos and lead paint. Repairs on such aging infrastructure are not always cost effective and can lead to lengthy projects and significant renovation or replacement of entire structures. It is increasingly difficult to identify and obtain adequate parts and to further locate the necessary expertise to work on this aging equipment. In addition, these facilities were not designed to meet modern standards of energy efficiency.

Q. What concerns or problems do these aging structures and facilities create for the Company's customers?

A. The population and infrastructure of the state of Michigan look much different than they did in the 1950s and 1960s. In 1950, the population of Michigan was 6,407,000 with growth focused in urban areas. The state's current population is now over 10 million, with much of the growth since the 1960s having occurred in suburban areas. The locations of some of the Company's facilities no longer allow the Company to optimize service to customers. In these situations, longer response times and increased drive times make meeting service delivery standards difficult for the Company's employees who are dedicated to providing the best service to Consumers Energy's customers. This issue is particularly pronounced at the Lansing Service Center, as I will discuss in detail later in my testimony.

Q. What process does Consumers Energy utilize to evaluate whether to make capital investments in facilities?

A. The Company has been using a formal assessment process for several years that evaluates whether or not to invest in a facility by studying each facility's overall health. The Company plans to continue using this process and is enhancing it by incorporating the operational priorities of the Facilities organization's internal business partners. Given the evolving nature of the workforce (i.e., with hybrid work) the Company is working on strategies to ensure its facilities are right sized for the needs of the work.

Q. What is the formal assessment process related to facility health?

A. A formal assessment process was established in 2016 to determine the need for capital investments in facilities. The assessment process is re-evaluated every two years resulting in minor updates to the methodology to reduce subjectivity in scoring. The most recent assessment was completed in 2022. The Facilities Department consists of qualified, trained, and certified experts in architecture, HVAC, plumbing, and electrical that conduct the assessment. In that process, an evaluation is made, on a multi-category scale, of certain conditions and characteristics of the structure and functions of the facility being assessed. For each facility, each condition and characteristic is scored (with a score of 1 to 5 per category), and then the facility is ranked on a multi-category scale (with an 80-point maximum score).

Q. What categories are included in the evaluation process of the Company's facilities?

A. Categories that are evaluated include: (i) safety (such as asbestos or other hazardous materials, traffic flow, and compatibility with surrounding areas); (ii) quality (such as workplace efficiency, employee comfort, and employee attraction and retention); (iii) cost (such as facility operating costs, space optimization, and energy efficiency); (iv) delivery (such as response times, driving distance within service territory, and sustainability of operations); and (v) morale (such as employee pride, wellness, and retention).

Q. How is the quality of each category identified above established?

A. The facility evaluated will fall within one of three quality designation categories depending on the score received. A score above 64 is designated as "Good"; a score of 48 to 64 is designated as "Serviceable," meaning that investment and/or replacement is needed; and a score under 48 is designated as "Poor," meaning that there are multiple systems failing at the facility. Facilities designated as "Poor" are typically candidates for replacement.

Q. What is the next step in the facility assessment?

A. Once the facility is initially evaluated and receives a quality designation, operational departments of the business then review and validate the raw scored ranking and adjust the ranking to reflect forecasted needs of the business. Facilities finalizes the score, and any facility that scores below a minimum acceptable level, 48 out of 80 points, may be targeted for renovation or replacement.

Q. How does the Facilities organization consider the business needs of its internal business partners when selecting locations to target and how do facility health assessments and evaluations of business partner needs combine to create a prioritization plan for Facilities work?

A. The Facilities organization considers business partner needs by meeting on a regular basis with business partners to review their business plans and the resulting impacts on the facilities necessary to support these plans. The process begins with a 10 Year Long Term Facilities Plan. This plan is maintained by the Facilities organization and contains fundamental information about each facility such as year the building was constructed, estimated years of useful life remaining in the building, dates of major milestones in the life of the building (e.g. significant renovations and building additions), etc. The 10 Year Long Term Facilities Plan is then used to inform creation of the Long Term Financial Plan ("LTFP"). The LTFP is a five-year financial plan created in part from the aforementioned facility health assessments. Facilities organization engineers and other technical experts across the Company (e.g. Company environmental analysts) generate the health assessments and develop capital investment priorities based on the health assessments (e.g. replacement of specific assets at specific buildings, preventive maintenance of specific building systems, work on a building envelope). These capital investment priorities are then reviewed by business partners for alignment with their business plans and can become projects incorporated into the LTFP. The ultimate list of capital investment projects incorporated into the LTFP is then derived from this collaboration between the Facilities organization and business partners. While considerable engineering rigor is applied to developing the facility health assessments, business partner priorities do affect the ultimate list of projects incorporated into the LTFP. The Kalamazoo Service Center Project included in this rate case, for instance, was elevated in priority to address hazardous material issues and negative employee engagement identified by business partners at the Kalamazoo Service Center.

Q. Does this process ensure priority is given to Facilities projects critical to ensuring the Company can serve its customers?

A. Yes. The facility health assessments and aforementioned planning process produces a prioritized list of facilities for renovation or replacement that is aligned with both the need to preserve and maintain facilities assets and support business plans in providing optimal customer service. Buildings that are in poor shape or are otherwise suboptimal negatively impact the Company's ability to serve customers.

Q. Are there situations in which prioritization of projects might change even after development of the LTFP?

A. Yes. Though not typical, reprioritization of projects after establishment of the LTFP can occur. For example, several years ago the Company reprioritized development of a service center in Tawas to provide timely support to customers in the greater Tawas region and to reduce the workload impact on local first responders during response to emergency utility events. In another example, the Company revised its plans for the Kalamazoo Service Center Project included in this case. In this instance, after examining the impacts of the COVID pandemic on the workforce and changes the pandemic brought in how work is performed, the Company revised its original plan to replace the Kalamazoo Service Center and instead decided to renovate portions of it as many of the building modifications originally proposed became more costly due to supply issues and were also deemed no longer necessary to support the post-COVID workforce.

Q. Is the Company taking steps to ensure its facilities are right-sized given changes in the working environment?

A. Yes. The Company is monitoring the use of its facilities in a post-COVID work environment. As the pandemic subsides, multiple internal organizations have established expectations for in-person work at Company facilities. As a result, Company facilities are continuously evaluated for alignment with current and anticipated work trends. In cases where underutilized workspace has been identified, the Company has divested or examined divesting such space. For example, in 2020, the Company terminated lease agreements for over 30,000 square feet of previously leased office space at the Commonwealth Commerce Center in Jackson. The Company will continue to evaluate space utilization with the goal of eliminating underutilized space and aligning business needs with space requirements.

<u>**Capital Spending Overview**</u>

Q. What programs are included in the projected capital expenditures for Facilities?

A. As demonstrated in Exhibit A-12 (QAG-1), Schedule B-5.6, Facilities capital spending is divided into two programs: (i) Asset Preservation; and (ii) Other Equipment. Capital spending is broken down into multiple standard cost categories, including contractor, labor, materials, business expenses, and other (loadings, chargebacks). Most Facilities capital spending, as reflected in Exhibit A-12 (QAG-1), Schedule B-5.6, is for Asset Preservation, which is broken down into four portfolio categories: emergent repairs, asset replacement, new construction, and renovations.

Other Equipment

Q. What is included in the Other Equipment program?

A. Other Equipment includes capital investments for wellness equipment; computer equipment; print equipment; Real Estate organization tools and equipment; Supply Chain organization tools and equipment; and Facilities organization tools. As shown in Exhibit A-12 (QAG-1), Schedule B-5.6, the Company is projecting to spend $1.1 million on Other Equipment in the 21-month bridge period and $644,000 on Other Equipment in the projected test year.

Q. Can you elaborate on what the various categories of Other Equipment spending represent?

A. Wellness Equipment consists primarily of equipment used by Operations personnel and others in the Company's fitness centers. Computer Equipment includes computers acquired for use by Operations Support personnel outside of routine lifecycle replacements. These include acquisitions of computer equipment obtained for a specialty use (e.g. a plotter) or replacement of computer equipment that fails prematurely for various reasons. Print Equipment consists of large copying and printing equipment for the Company's Administrative Operations and Mail Room. Real Estate Tools and Equipment consists primarily of survey equipment. Supply Chain Tools and Equipment consists of tools and equipment acquired for material storerooms such as shelving.

Q. How did the Company determine this level of investment for Other Equipment?

A. Levels of investment are set to meet identified needs of the business. The Facilities organization considers business partner needs by meeting on a regular basis with business partners to review their business plans.

Emergent Repairs

Q. What capital expenditures are included in the Emergent Repairs portfolio category?

A. Emergent Repairs includes unplanned corrective maintenance and break fix repair of assets. As shown in Exhibit A-71 (QAG-3), the Company is projecting to spend $2.1 million in the 21-month bridge period and $1 million in the projected test year on emergent repairs. The Company maintains data on the age, condition, and maintenance history of its major building system assets. This data, in conjunction with historical spend, is used to forecast projected spend on unplanned corrective maintenance and break fix repair of assets.

Asset Replacement

Q. What capital expenditures are included in the Asset Replacement portfolio category?

A. The Asset Replacement portfolio category includes capital replacement of paved surfaces such as parking lots and driveways; roofing; mechanical and electrical equipment in buildings; and furniture. As shown in Exhibit A-71 (QAG-3), the Company is projecting to spend $12.9 million on Asset Replacements in the 21-month bridge period and $8.8 million on Asset Replacements in the projected test year.

Q. How are Asset Replacement projects targeted?

A. Similar to the aforementioned facility health assessments, asset condition assessments are performed by Facilities engineers on a regular basis. For example, for roofing assets, a portion of roof sections is inspected annually such that all roofs are inspected once every three years. The condition of each assessed asset is ranked following standard industry-recognized methodologies. Those assets assessed to be below acceptable condition are targeted for renovation or replacement.

Q. How does the Company identify locations for paving projects?

A. The condition of paving assets is evaluated following standard industry practices on a rolling five-year basis with a condition assessment performed annually for 20% of Company sites. Paving assets are prioritized for replacement based on the lowest assessed condition index score. Paving projects may include other related enhancements to paved surfaces such as new drainage or new lighting.

Q. How did the Company determine the amount of needed investment in paving projects for the bridge period and the test year?

A. Specific paving sections are identified for replacement based on the results of the condition assessment. Cost estimates are prepared utilizing historical data from similar paving asset replacement projects performed during approximately the last five years. The aggregate area of paving to be replaced each year varies based on the results of the condition assessments.

Q. How does the Company identify locations for roofing projects?

A. The condition of roofing assets is evaluated on a rolling three-year basis with a visual inspection and detailed infrared inspection performed annually for 33% of Company sites. Roofing assets are prioritized for replacement based on the lowest assessed condition index score.

Q. How did the Company determine the amount of needed investment in roofing projects for the bridge period and the test year?

A. The total amount of needed investment in roofing projects is established using the five-year historical average spend. The roof condition assessments are then used to determine how that spend is allocated.

Q. How does the Company identify locations for mechanical and electrical projects?

A. The condition of mechanical and electrical assets is evaluated by Facilities engineers for all Company sites. Based on the results of these evaluations, targeted maintenance work is performed on mechanical and electrical assets. Where the condition of mechanical and electrical assets is determined to be below an acceptable threshold for targeted repair or maintenance, the mechanical and electrical assets are prioritized for replacement based on the results of these evaluations. The condition of these assets is determined to be below an acceptable threshold for targeted maintenance once the cost of maintenance exceeds the cost of replacement and/or the risk of obsolescence of replacement parts becomes too great.

Q. How did the Company determine the amount of needed investment in mechanical and electrical projects for the bridge period and the test year?

A. Cost estimates are prepared utilizing historical cost data for each of the mechanical and electrical assets prioritized for replacement. Cost estimates are prepared utilizing historical data from similar mechanical and electrical projects performed during approximately the last five years. Whether the facility in which the mechanical and electrical project is being performed serves only Company gas customers, only Company electric customers, or serves combination electric and gas customers impacts how mechanical and electrical project costs are allocated. In this case, the increase from $2.6 million in the historical year to $5 million in the 12-month bridge period ending December 31, 2023 is largely attributable to the fact that the mechanical and electrical projects being performed during the 12-month period ending December 31, 2023 are being performed primarily in Company facilities that serve only gas customers. Mechanical and electrical projects performed during the historical year were performed primarily in Company facilities that serve only electric customers and facilities that serve combination electric and gas customers.

Q. How does the Company identify locations for elevator projects?

A. The condition of elevator assets for all Company sites are evaluated by outside consultants and subject matter experts. Elevator assets are prioritized for replacement based on the results of these evaluations utilizing a condition assessment score of 1 to 5. Elevators with an assessment score of 3 or below are targeted for modernization or replacement.

Q. How did the Company determine the amount of needed investment in elevator projects for the bridge period and the test year?

A. Cost estimates are prepared utilizing historical cost data for each of the elevator assets prioritized for modernization. Cost estimates utilize historical data from similar elevator asset projects performed during approximately the last five years. The cost per individual elevator modernization or replacement varies from year to year depending on the number of floors served by the elevator, weight rating of the elevator, and elevator drive type. Whether the facility in which elevator modernization is being performed serves only Company gas customers, only Company electric customers, or serves combination electric and gas customers also impacts how elevator asset project costs are allocated. In this case, the increase from $22,000 in the historical year to $196,000 in the 12-month bridge period ending December 31, 2023 is largely attributable to the fact that the elevator asset projects being performed during the 12-month period ending December 31, 2023 are being performed primarily in Company facilities that serve only gas customers. Elevator asset projects performed during the historical year were performed primarily in Company facilities that serve only electric customers and facilities that serve combination electric and gas customers.

Q. How does the Company identify where furniture replacements are needed?

A. Furniture replacement is determined based on business need. Subject matter experts evaluate business unit requirements and existing furniture. Where the existing furniture does not meet business unit requirements the furniture is identified for replacement.

Q. How did the Company determine the amount of needed investment in furniture for the bridge period and the test year?

A. Cost estimates are prepared utilizing historical cost data for each of the furniture assets prioritized for replacement. Furniture project cost estimates utilize historical data from similar furniture asset projects performed during approximately the last five years. Furniture materials are redeployed to compatible users when feasible.

New Construction

Q. What capital expenditures are included in the New Construction portfolio category?

A. The New Construction portfolio category includes major projects to build new structures, either on existing Company property or on new properties the Company acquires. As shown in Exhibit A-71 (QAG-3), the Company is projecting to spend $10.7 million on New Construction in the 21-month bridge period and $9.5 million on New Construction in the test year.

Q. Has the Company identified projects in the New Construction portfolio category?

A. Yes. The Company's New Construction projects are listed in Exhibit A-71 (QAG-3) and are as follows:

- Lansing Service Center

- Hastings Service Center
- Gas City Training
- Gas Construction Project

Q. Does the Company consider environmental impacts when planning for new construction?

A. Yes. New buildings are constructed to meet the United States Green Building Council ("USGBC") standards (see usgbc.org), and the Leadership in Energy and Environmental Design ("LEED") standards (see usgbc.org/leed), with specific emphasis on reduced energy consumption, sustainability, and reduced operating cost.

Q. Do these environmental building standards benefit the Company's customers?

A. Yes. When compared to conventional construction, buildings designed to LEED standards reduce lifetime energy consumption by 30% or more, resulting in reduced operational costs which allow customers to pay less for utility costs. In addition, new buildings require less maintenance and are easier to maintain than an aged structure, resulting in an estimated 5% cost reduction. Consumers Energy's recently constructed Coldwater Service Center was designed and built to these standards.

Q. Describe the Lansing Service Center Project. What is its overall goal?

A. In this project, the Company has purchased land in a new location and will construct a new facility on that property. This facility will allow the Company to retire its existing facility (which will be demolished and retained to address and abate environmental concerns resulting from the operation of a former Manufactured Gas Plant ("MGP") on the site). This new facility will house many employees currently working out of the existing service center. The Company anticipates a portion of these employees will have a hybrid work arrangement in which the employees perform some work tasks at the Lansing Service Center and some work tasks elsewhere including their homes. Employees with a hybrid work arrangement will require collaborative space and transient shared office space in the facility when they are on-site to work with other personnel.

Q. What alternatives to the construction of a new Lansing Service Center did the Company consider?

A. The Company considered the following three alternatives: (1) Do nothing; (2) Renovate the existing Lansing Service Center; and (3) Construct a new facility at a new location, with multiple locations considered. The option to construct a new facility at a new location was determined optimal.

Q. Why has the Company chosen to build a new Lansing Service Center?

A. As demonstrated in Exhibit A-72 (QAG-4), a Facilities assessment of the existing Lansing Service Center produced a score of 39, placing the existing Lansing Service Center in the quality designation of "Poor." This information led the Company to rule out a "do nothing" option, and problems with the existing facility's location led the Company to rule out building a new facility on the same site. The existing facility is built on the site of a former MGP, with impacted soil materials underlying the building and other structures. The existing facility is also located within the Grand River flood plain with the building floor elevation three feet below the river's flood stage. Additionally, the existing facility is in a residential neighborhood and is served by a local road network with schools nearby, resulting in large truck traffic being routed through the residential area, which may be a safety hazard for residents (especially children). Crime in the existing area is also a problem as the site has experienced multiple law enforcement incidents involving the pursuit of armed suspects through the property, including areas within the secured perimeter. These incidents have resulted in the Company's inability to move vehicles out of the service center (while police officers were pursuing suspects), and a general level of unease regarding the safety and security of employees.

Q. Please elaborate on the reasons the Company decided to build a new Lansing Service Center.

A. As reflected in the scores set forth in Exhibit A-72 (QAG-4), there are several reasons the Company has chosen to relocate the existing Lansing Service Center. These reasons range from the age of the building to customer accessibility. First, the existing service center building was built in 1958. Over time, systems of the building, including major mechanical and electrical systems, even with regular maintenance and replacement, are beyond their useful lives. Currently, these systems require substantial renovations/replacement. Additionally, the existing service center is located in a residentially zoned neighborhood and due to the location, does not allow Gas Operations to meet customer needs in a timely fashion. Further, the roads (because of the residential zoning) are inadequate for the size of equipment utilized in and out of the service center and there are often children in the vicinity, which creates significant safety concerns. The current site is also located within the floodplain of the Grand River with the finish floor elevation located three feet below the major flooding elevation projected by the Federal Emergency Management Agency. All these considerations negatively impact the Company's ability to dispatch both personnel and equipment to serve customers. Other considerations supporting the decision to construct a new facility, rather than renovate the existing facility, include operating cost reductions, security, and environmental abatement. Because of all of these factors, the

Company has decided to build a new Lansing Service Center at a new location, with the evaluation of potential locations summarized in Exhibit A-72 (QAG-4).

Q. Can you elaborate further on the security and environmental abatement issues at the Lansing Service Center?

A. Yes. The site has experienced multiple law enforcement incidents, some involving the pursuit of armed suspects across and through the property, including areas within the secured perimeter. These incidents have resulted in lock-down safety protocol implementation for employees and a resulting general level of unease regarding the safety and security of employees, customers, and others, while on the property and when accessing or leaving the property. Environmental issues arise from the use of the current Lansing Service Center site as the location of a former MGP regulated under Public Act 451 of 1994, Part 201. This site has historical environmental contamination issues resulting from operation of the MGP, including significant underground impacted soil materials (i.e., coal tar residual). Additionally, the facility contains asbestos insulation for pipe and duct work, asbestos flooring, and has significant areas of lead paint in poor and peeling condition. Given these environmental issues, upgrades to the facility (e.g. carpet replacement and open space enhancement) cannot be cost effectively completed.

Q. Has the Company engaged in an environmental study for the area contemplated for the new Lansing Service Center?

A. Yes. The proposed new site for the Lansing Service Center includes previous agricultural use; thus, no environmental impacts are anticipated from this previous use. A Phase 1 Environmental investigation has been completed. The proposed site contains wetland areas and current development plans envision leaving these wetland areas undisturbed. A wetland assessment has also been completed.

Q. What energy efficiency and waste reduction measures does the Company plan to install at the new Lansing Service Center?

A. The proposed new Lansing Service Center facility is planned to be designed and constructed to achieve certification under the USGBC, LEED version 4 rating system.

Q. In addition to these operational benefits, will building a new Lansing Service Center provide financial benefits for customers?

A. Yes. The operating cost for the existing Lansing Service Center is $6.38 per square foot. The operating cost for the existing Lansing Service Center is in large part attributable to maintaining the facility's major mechanical, electrical, and other systems which are beyond their useful lives. The new Lansing Service Center operating cost is expected to be $5.75 per square foot with total annual operating costs of $718,750. This translates to an approximate 25% reduction in total annual operating cost or $242,114 from the 2022 total annual operating cost. See Exhibit A-72 (QAG-4).

Q. The Lansing Service Center Project includes the relocation of that facility to a different part of the Lansing metropolitan area. Can you explain what is considered generally when considering relocation of a facility?

A. Yes. As noted earlier, Company facilities are assessed and scored based on multiple criteria (i.e., safety, quality, cost, delivery, and morale) to provide a holistic score that informs the Company of the possible need to make investments to make improvements. Facilities with scores falling below the acceptable range are targeted for renovation or replacement. Part of the overall analysis, which is relevant to the Lansing Service Center, is the geographic location of targeted facilities. Geographic locations are analyzed against customer workload distribution within the service territory to determine optimal location for the facility. Facilities that are determined to be mis-located within the customer service territory are evaluated for relocation to a newly constructed site with the goal of improved customer response. Facilities determined to already be optimally located within the customer service territory are evaluated for renovation or reconstruction on the existing site.

Q. How did the Company determine the new location for the Lansing Service Center?

A. An analysis of customer distribution across the service territory where the Lansing Service Center is located, and potential service center locations within that service territory, determined the optimal area to minimize response times. This analysis is reflected in Exhibit A-72 (QAG-4). Reducing customer response times lowers fuel costs by minimizing the distance Company employees must travel to job sites. Determining the optimal area to minimize response times also maximizes employee efficiency by reducing labor hours required to reach and service customers. The current location of the Lansing Service Center is offset to the north and east of the optimal location, in a residentially zoned neighborhood, and the current location does not provide readily available highway access. The current location of the Lansing Service Center within the service territory results in increased customer response times, higher fuel costs, and reduced employee efficiency due to increased travel times as explained above. The location for the new Lansing Service Center will not only be in a more appropriately zoned area but will also provide improved customer response times. See Exhibit A-72 (QAG-4).

Q. Has land been acquired for the Lansing Service Center? If so, please identify the location of the land.

A. Yes. Land was acquired for the Lansing Service Center in December 2020, located in Windsor Charter Township, at the southeast corner of the intersection of Canal Road and Billwood Highway, Dimondale, Michigan 48821. The Conceptual Site Plan for the New Lansing Service Center is included in Exhibit A-72 (QAG-4).

Q. What type of operations departments will work at the new Lansing Service Center as compared to the existing Lansing Service Center?

A. The existing Lansing Service Center houses the following operations: Customer Experience; Gas Operations; Enterprise Project Management/Environmental Services; Gas Engineering & Supply; Generation Operations & Compression; Information Technology ("IT"); Electric Operations; Operations Performance; Shared Services; and People & Culture. The Company anticipates personnel from some (not all) of these operating groups to be housed in the new Lansing Service Center. Because the new facility is being constructed to better serve the Company's customers in the Lansing area, only Company personnel dedicated to servicing these customers need to be housed in the new Lansing Service Center.

Q. Approximately how many employees will work at the new Lansing Service Center as compared to the existing Lansing Service Center?

A. Over 400 employees are assigned to the existing Lansing Service Center. The Company anticipates the new Lansing Service Center will house some (not all) of these employees with some adaptation in their use of the workspace including some employees adopting a hybrid work arrangement, requiring only collaborative space and transient shared office space in the facility when they are on-site to work with other personnel.

Q. Has the Commission previously approved costs associated with the Lansing Service Center Project?

A. Yes. In Case No. U-20963, the Company proposed to spend \$1,831,000 in a 2021 bridge year and \$11,445,000 in a 2022 test year on the Lansing Service Center project. In the Commission's December 22, 2021 Order in Case No. U-20963, the Commission acknowledged that the Lansing Service Center project would have further costs in subsequent years and found that the project was well-supported. The Commission therefore approved the project as presented in that case.[1]

Q. Have plans for construction of the Lansing Service Center changed since the Commission's Order in Case No. U-20963? If so, please elaborate.

A. Yes. The schedule for construction of the Lansing Service Center has changed slightly due in large part to supply chain and labor issues stemming from the Covid-19 pandemic. In light of the Covid-19 pandemic, the Company reevaluated its plans to ensure the new Lansing Service Center is designed and constructed in a manner that optimizes use of the facility for a hybrid work arrangement. As a result, the Lansing Service Center project is now projected to cost \$46.8 million. This is a 15% reduction from the total cost of \$54.8 million projected in Case No. U-20963. See Exhibit A-78 (QAG-10).

[1] MPSC Case No. U-20963, December 22, 2021 Order, pages 160-162

Q. How much did the Company invest in the Lansing Service Center Project in the 2022 historical year in this case?

A. In the 2022 historical year in this case, the Company invested $262,000 (gas allocation) in this project. See Exhibit A-71 (QAG-3). Expenditures in the 2022 historical year were for design engineering a municipal water main extension to the project site, pipe materials for the water main extension, and completion of an alternatives analysis for the project.

Q. How much does the Company project to invest in the Lansing Service Center Project in the bridge period and test year in this case?

A. As shown in Exhibit A-71 (QAG-3), the Company is projecting to invest $5.3 million (gas allocation) in the Lansing Service Center in the 21-month bridge period and $7 million (gas allocation) in the test year. As shown in the chart below and in Exhibit A-78 (QAG-10), the overall project is anticipated to cost $46.8 million.

__**Lansing Service Center Plan Costs**__

Location		Historical Cost 2022	Total Plan Cost 2023	Total Plan Cost 2024	Total Plan Cost 2025	Total Plan Cost 2026	Total Cost
Lansing	Master Planning						$0
	Programming	$159,946					$159,946
	Land Acquisition						$0
	Engineering	$412,304	$1,950,000	$100,000	$100,000		$2,562,304
	Construction		$2,847,757	$11,660,988	$17,948,363	$9,426,397	$41,883,505
	Furnishings					$1,750,000	$1,750,000
	Commissioning					$425,000	$425,000
		$572,250	$4,797,757	$11,760,988	$18,048,363	$11,601,397	$46,780,755

Q. How have these projected costs been derived?

A. Outside consultants were engaged to develop and prepare a detailed design program and four conceptual design alternatives for the Lansing Service Center project. The alternatives considered various construction elements and building configurations to meet the program requirements. These alternatives were then evaluated by an outside construction management firm to develop project cost estimates for each design alternative.

Q. What is the status of the Lansing Service Center Project at the time of this filing? What work has been completed so far, and what work is still remaining to be done?

A. Land acquisition and rezoning of the parcel in Dimondale has been completed. Design engineering and bidding have been completed and a contract awarded for a municipal water main extension to the project site. The pipe materials have been ordered for the water main extension. An alternatives analysis has been completed for the project considering four potential alternative design scenarios. A design-build contract for construction management services has been competitively bid and awarded. Architectural design of the building is in progress.

Q. Please describe the Hastings Service Center Project. What is its overall goal?

A. The Company is planning to construct a new Hastings Service Center at the existing service center location to include an adjacent property that the Company is negotiating to purchase from the adjacent landowner. This new facility will house most employees currently working at the existing service center. A portion of the employees currently working at the existing service center will have a hybrid work arrangement and will require only collaborative space and transient shared office space in the facility when they are on-site to work with other personnel.

Q. What alternatives to the construction of a new Hastings Service Center did the Company consider?

A. The Company considered four alternatives: (1) Do nothing; (2) Renovate the existing Hastings Service Center; (3) Demolish the existing building and construct a new building on site; and (4) Construct a new facility at a new site. The options to either demolish the existing building and construct a new building on site or demolish the existing building and construct a new building at a larger site were identified as optimal depending on availability of suitable land.

Q. Why has the Company chosen to construct a new Hastings Service Center facility?

A. As demonstrated in Exhibit A-73 (QAG-5), a Facilities assessment of the existing Hastings Service Center produced a score of 41. As discussed above, because this score falls below a score of 48, it was targeted for replacement, and the "do nothing" option was ruled out. For the same reason that the Lansing Service Center was targeted for replacement, including aging infrastructure, which is beyond useful life, the Hastings Service Center was determined to need replacement. The current site is fully developed and is no longer sufficient to support ongoing utility operations as the site lacks adequate space for both safe vehicle maneuvering and utility construction material storage. In addition, the existing building envelope does not comply with current energy code requirements. The Facilities organization, therefore, ruled out the renovation option for the Hastings Service Center. The existing Hastings Service Center site is located within an industrialized area with access to major roads and highways. The Company determined that the facility is currently in an optimal location to service customers (see Exhibit A-73 (QAG-5)). Therefore, with the acquisition of appropriate adjacent parcels, the Hastings Service Center has been targeted for replacement on the existing site in lieu of relocation. Other considerations supporting the decision to replace the existing site include operating cost reductions and environmental abatement.

Q. Can you further elaborate on how these alternatives were compared?

A. The Company originally sought to construct a new facility on the existing property. Construction of the new Hastings Service Center on the existing property was predicated on reaching an agreement with the adjacent landowner to transfer a portion of their property to Consumers Energy. This would increase the available site area for development and provide enough space for the new facility. Agreement for a property transfer with an adjacent landowner was not reached, and the properties on the west and east are fully developed. The Company then entered negotiations with the Barry County Road Commission (owner of the adjacent parcel to the south). The Barry County Road Commission approved the Company's conceptual plan for development of this parcel. The Company now anticipates completing acquisition of the parcel in the fourth quarter of 2023 which will allow for expansion of the existing Hastings site and construction of the new facility.

Q. What energy efficiency and waste reduction measures does the Company plan to install at the new Hastings Service Center?

A. The proposed new Hastings Service Center facility is planned to be designed and constructed to achieve certification under the USGBC, LEED version 4 rating system. The proposed new Hastings Service Center is also planned to incorporate on-site solar power generation to partially offset building energy consumption.

Q. In addition to these operational and environmental benefits, will building a new Hastings Service Center provide financial benefits for customers?

A. Yes. The operating cost for the existing Hastings Service Center is $13.85 per square foot. See Exhibit A-73 (QAG-5). One factor in the existing Hastings Service Center operating cost per square foot is the cost of maintaining the facility's major mechanical, electrical, and other systems which are beyond their useful lives. Another significant factor impacting the existing facility's cost per square foot is the fact that at 12,317 square feet, the existing

Hastings Service Center is smaller than many of the Company's other Service Centers across Michigan thus resulting in a higher operating cost per square foot (i.e. fixed operating costs for a smaller building footprint). The new Hastings Service Center operating cost is expected to be less than or equal to $9.70 per square foot. This is an approximate 30% reduction in the facility's operating costs per square foot from the current $13.85 per square foot. See Exhibit A-73 (QAG-5).

Q. Will this building be larger or smaller than the existing Hastings Service Center?

A. The conceptual site plan for the new service center is shown in Exhibit A-73 (QAG-5). The original projected building area based on conceptual data assembled is larger than the existing Hastings Service Center by 11,183 square feet. The new facility is designed with a larger footprint to address multiple deficiencies at the existing facility that negatively impact electric operations including insufficient space for crew rooms, parts and material storage, welding operations, and automotive tools and repairs. Even at 23,500 square feet, however, the projected building area of the new Hastings Service Center, based on conceptual data, is smaller than many of the Company's Service Centers.

Q. What type of operations departments will work at the new Hastings Service Center as compared to the existing Hastings Service Center?

A. The existing Hastings Service Center houses the following operations: Customer Experience; Gas Operations; Enterprise Project Management/Environmental Services; IT (Information Technology); Electric Operations; and Shared Services. The Company anticipates the new Hastings Service Center will house many of these same operations.

Q. Approximately how many employees will work at the new Hastings Service Center as compared to the existing Hastings Service Center?

A. The existing Hastings Service Center houses approximately 50 employees. The Company anticipates the New Hastings Service Center will house a comparable number of employees with a portion of these employees having a hybrid work arrangement and requiring only collaborative space and transient shared office space in the facility when they are on-site to work with other personnel.

Q. Has the Commission previously approved costs associated with the Hastings Service Center Project?

A. Yes. In Case No. U-20963, the Company proposed to spend $458,000 in a 2021 bridge year and $4,807,000 in a 2022 test year on the Hastings Service Center project. In the Commission's December 22, 2021 Order in Case No. U-20963, the Commission acknowledged that the Hastings Service Center project would have further costs in subsequent years and found that the project was well-supported. The Commission therefore approved the project as presented in that case.[2]

Q. Have plans for construction of the Hastings Service Center changed since the Commission's Order in Case No. U-20963? If so, please elaborate.

A. Yes. As discussed above, the Company encountered unanticipated difficulties acquiring property to expand the Hastings Service Center. This has delayed the projects timeline. In addition, the Company has reevaluated its plans to ensure the new Hastings Service Center is designed and constructed in a manner that optimizes a hybrid work arrangement. As a result, the Hastings Service Center project is now projected to cost $17 million. This is a

[2] MPSC Case No. U-20963, December 22, 2021 Order, pages 160-162

17% reduction from the total cost of $20.5 million projected in Case No. U-20963. See Exhibit A-78 (QAG-10).

Q. How much did the Company invest in the Hastings Service Center project in the historical year in this case?

A. In the 2022 historical year in this case, the Company invested $2,000 (gas allocation) in this project. See Exhibit A-71 (QAG-3).

Q. How much does the Company project to invest in the Hastings Service Center Project in the bridge period and test year in this case?

A. As shown in Exhibit A-71 (QAG-3), the Company is projecting to invest $441,000 (gas allocation) in the Hastings Service Center in the 21-month bridge period and $2.5 million (gas allocation) in the test year. As shown in Exhibit A-78 (QAG-10), the overall project is anticipated to cost $17 million.

Q. How have these projected costs been derived?

A. A conceptual plan was prepared and high-level order of magnitude estimate (+50% /- 30%) was developed based on historical data for similar projects.

Q. What is the status of the construction of the Hastings Service Center at the time of this filing? What work has been completed so far, and what work is still remaining to be done?

A. Conceptual plans and cost estimates for the project have been developed. The Barry County Road Commission (owner of the adjacent parcel to the south) has approved the Company's conceptual plan for development of the parcel and the Company now anticipates completing acquisition of the parcel in the fourth quarter of 2023. A Phase 1

Environmental Study has also been completed and a Phase 2 Environmental Study is now in progress.

Q. Please describe the Gas City Training Project.

A. The Gas City Training Project was the development of a holistic learning platform, in the form of a Gas City, to allow employees in training to understand and experience gas infrastructure work from start to finish. This project was designed and constructed at the Flint Service Center.

Q. How much does the Company project to invest in the Gas City Training Project in the bridge period and test year in this case?

A. As shown in Exhibit A-71 (QAG-3), the Company is projecting to invest $508,000 in the Gas City Training Project in the 21-month bridge period and $0 in the test year.

Q. What is the status of the construction of the Gas City Training Project at the time of this filing? What work is still remaining to be done?

A. Construction is complete and the project is in closeout.

Q. Please describe the Gas Construction Project. What is its overall goal?

A. A complete description of the Enhanced Infrastructure Replacement Program ("EIRP") and its overall goals is outlined in the testimony of Company witness Kristine A. Pascarello. To support Company crews and contractor resources performing replacement of pipe and main assets as part of EIRP, the Company has identified and leased six facilities that will be used to store equipment, vehicles, and other assets used in EIRP. These six facilities will also serve as operation hubs to which EIRP Company crews and contractor resources will report for the duration of the EIRP project in those geographic areas. This testimony is tailored very narrowly to a discussion of the upgrades of building systems and grounds at these six leased sites that are necessary to ensure the facilities are fit for use as EIRP reporting and operation hubs.

Q. Where are the facilities being used as EIRP reporting and operation hubs located?

A. The six facilities being used as EIRP reporting and operation hubs are located as follows:

Location	Address
Holly Gas Construction	4100 East Baldwin Road, Grand Blanc, MI 48139
Jolly Road Construction	1500 East Jolly Road, Lansing, MI 48910
Midland Gas Construction	1850 Bay City Road, Midland, MI 48642
Madison Heights Gas Construction	111 East 12 Mile Road, Madison Heights, MI 48071
Macomb Gas Construction	27432 Groesbeck Highway, Roseville, MI 48066
Saginaw Gas Construction	2119 River Street, Saginaw, MI 48601

Q. How much does the Company project to invest in the Gas Construction Project in the bridge period and test year in this case?

A. As shown in Exhibit A-71 (QAG-3), the Company is projecting to invest $4.5 million in the Gas Construction Project in the 21-month bridge period and $0 in the test year.

Q. What is the status of the construction of the Gas Construction Project at the time of this filing? What work is still remaining to be done?

A. See chart below and Exhibit A-74 (QAG-6).

<u>Gas Construction Project Milestones</u>

Project	Procurement / Permits / Approvals	Construction / Renovation	Closeout	Current Status
Holly Gas Construction	October 2023 - November 2023	November 2023 - May 2024	July 2024 - October 2024	In construction / renovation
Jolly Road Construction	October 2023 - December 2023	December 2023 - September 2024	September 2024 - December 2024	In construction / renovation
Midland Gas Construction	November 2022 - December 2022	January 2023 - August 2023	September 2023 - December 2023	In closeout
Madison Heights Gas Construction	August 2022 - October 2022	November 2022 - April 2023	May 2023 - August 2023	Complete
Macomb Gas Construction	November 2022 - December 2022	January 2023 - May 2023	June 2023 - July 2023	Complete
Saginaw Gas Construction	April 2023 - June 2023	July 2023 - July 2024	August 2024 - October 2024	In construction / renovation

<u>Renovations</u>

Q. What capital expenditures are included in the Renovations portfolio category?

A. The Renovations portfolio category includes major modifications to the interior and/or exterior of existing facilities (e.g. adding a garage to a building). As shown in Exhibit A-71

(QAG-3), the Company is projecting to spend $4.5 million on Renovations in the 21-month bridge period and $6.8 million on Renovations in the test year.

Q. Has the Company identified projects in the Renovations portfolio category?

A. Yes. As shown in Exhibit A-71 (QAG-3), the Company has identified the following Renovations projects:

- Kalamazoo Service Center
- Parnall Renovations (P1-3)
- Jackson Dispatch
- Electric Vehicle ("EV") Infrastructure

Q. Describe the Kalamazoo Service Center project. What are its overall goals?

A. In this project, the Company is renovating the existing Kalamazoo Service Center. The Company will remediate environmental concerns, workspace concerns, and problems with aging building systems at the existing facility upon completion of this renovation. The renovations of this facility will entail adding insulation to exterior walls, installation of new exterior doors and windows, new roofing membrane and roof insulation, new interior finishes, new furnishings, new plumbing fixtures and fittings, new HVAC equipment and ductwork, and new energy efficient lighting systems.

Q. What alternatives to the renovation of the Kalamazoo Service Center did the Company consider?

A. The Company considered the following three alternatives: (1) Do nothing; (2) Renovate the existing Kalamazoo Service Center; and (3) Demolish the existing building and construct a new building on site. The option to renovate has been identified as optimal. See Exhibit A-75 (QAG-7).

Q. How did the Company decide to renovate the existing service center?

A. The Company originally planned to construct a new facility on the existing property, as discussed in Case No. U-20963. In Case No. U-20963, the Company's projected total cost for the new Kalamazoo Service Center was $52 million. After reevaluating its original plans, the Company found additional cost savings for customers. The Company's updated projected total cost for the new Kalamazoo Service Center is now $34 million, an approximate 35% reduction in cost (see Exhibit A-78 (QAG-10)). The Company determined that a renovation would meet its workforce needs and provide better value for customers by minimizing the scope of architectural work required to achieve needed improvements in the facility (see Exhibit A-75 (QAG-7)). A renovation of the existing Kalamazoo Service Center will maximize utilization of the building's existing space, while minimizing disruptions to the Company's operations. Specifically, a renovation will minimize disruptions both to areas that house the Company's operating crews and to areas where the equipment and vehicles that crews use to service customers are maintained and serviced. Other considerations supporting the decision to renovate the existing facility include the fact that the Kalamazoo Service Center is already optimally located for responding timely to the Company's customers (see Exhibit A-75 (QAG-7)) and a renovation will yield an estimated 10% reduction in energy use (see Exhibit A-75 (QAG-7)).

Q. Why is doing nothing not a viable option at this location?

A. As shown in Exhibit A-75 (QAG-7), a Facilities assessment of the existing Kalamazoo Service Center produced a score of 46. Since this assessment was conducted, additional asbestos issues have been identified at this site (i.e., spray applied fireproofing, pipe wrap, floor tiles, etc.). All employees at this site have had to be moved to the second floor of the building due to air quality issues rooted in the growth of mold and related asbestos concerns on the first floor. This limited space is inadequate for the Company's Electric and Gas Operations partners to operate. In addition to its environmental concerns, the existing Kalamazoo Service Center was constructed in 1965, and its continuing use is inadequate due to aging infrastructure. Most of the existing systems throughout the facility are now over 50 years old and beyond their useful life. The space requirements of the existing workforce have changed as more personnel adopt a hybrid work arrangement requiring only collaborative workspace and transient shared office space when they are in the office working collaboratively with others. Finally, the existing Kalamazoo Service Center is optimally located for responding timely to the Company's customers (see Exhibit A-75 (QAG-7)) and, therefore, remaining at the current location best supports the Company's intent to provide timely service to its customers in the Kalamazoo area.

Q. What is the projected size of the renovated Kalamazoo Service Center?

A. Square footage of the renovated Kalamazoo Service Center is anticipated to be 147,100 square feet as shown in Exhibit A-75 (QAG-7).

Q. Is the projected size of the renovated Kalamazoo Service Center larger or smaller than the existing Kalamazoo Service Center?

A. The size of the renovated Kalamazoo Service Center is not projected to vary significantly from the size of the existing Kalamazoo Service Center because there is no anticipated change in the overall footprint of the facility. See Exhibit A-75 (QAG-7).

Q. What type of operations departments will work at the new Kalamazoo Service Center as compared to the existing Kalamazoo Service Center?

A. The existing Kalamazoo Service Center houses the following operations: Customer Experience; Gas Operations; Enterprise Project Management/Environmental Services; Information Technology (IT); Electric Operations; Operations Performance; Shared Services; and Public Affairs. The Company anticipates personnel from some (not all) of these operating groups to be housed in the renovated Kalamazoo Service Center.

Q. Approximately how many employees will work at the renovated Kalamazoo Service Center as compared to the existing Kalamazoo Service Center?

A. Approximately 250 employees are assigned to the existing Kalamazoo Service Center. The Company anticipates the renovated Kalamazoo Service Center will house the majority (not all) of these employees with some employees adopting a hybrid work arrangement and requiring only collaborative space and transient shared office space in the facility when they are on-site to work with other personnel.

Q. What energy efficiency and waste reduction measures does the Company plan to install at the renovated Kalamazoo Service Center?

A. The renovated Kalamazoo Service Center is planned to be designed and constructed to achieve certification under the USGBC, LEED version 4 rating system.

Q. What financial benefits will this renovation provide for customers?

A. The 2022 total annual operating cost for the existing Kalamazoo Service Center was $952,924 (see Exhibit A-75 (QAG-7)). As noted above, the first floor of the existing Kalamazoo Service Center is not in use due to air quality and asbestos concerns. Hence, the existing facility's total annual operating costs would likely be higher were the first floor in normal use. The renovated Kalamazoo Service Center total annual operating cost is expected to be $679,430, a nearly 30% reduction from the existing Kalamazoo Service Center 2022 total annual operating cost.

Q. Has the Commission previously approved costs associated with the Kalamazoo Service Center project?

A. Yes. In Case No. U-20963, the Company proposed to spend $945,000 in a 2021 bridge year and $13,111,000 in a 2022 test year on the Kalamazoo Service Center project. In the Commission's December 22, 2021 Order in Case No. U-20963, the Commission acknowledged that the Kalamazoo Service Center project would have further costs in subsequent years and found that the project was well-supported. The Commission therefore approved the project as presented in that case.[3]

Q. Have plans for the Kalamazoo Service Center project evolved since the Commission's Order in Case No. U-20963? If so, please elaborate.

A. Yes. As discussed above, the Company reevaluated its plans and determined that renovating the existing service center was a superior option to building a new structure and demolishing the old one. The revision of the Company's plans resulted in a modified spending plan. See Exhibit A-78 (QAG-10).

Q. How much did the Company invest in the Kalamazoo Service Center project during the historical year of this case?

A. The Company invested $153,000 (gas allocation) in this project during the 2022 historical year in this case. See Exhibit A-71 (QAG-3).

[3] MPSC Case No. U-20963, December 22, 2021 Order, pages 160-162.

Q. How much does the Company project to invest in the Kalamazoo Service Center project in the bridge period and test year in this case?

A. As shown in Exhibit A-71 (QAG-3), the Company is projecting to invest $3.5 million (gas allocation) in the Kalamazoo Service Center in the 21-month bridge period and $6.6 million (gas allocation) in the test year. As shown in the chart below, the overall project is anticipated to cost $34 million.

<u>Kalamazoo Service Center Plan Costs</u>

Location				Historical Cost 2022	Plan Cost 2023	Plan Cost 2024	Plan Cost 2025	Plan Cost 2026	Plan Cost 2027	Total Cost
Kalamazoo SC	Master Planning									$0
	Programming			$334,472						$334,472
	Land Acquisition									$0
	Engineering				$1,312,988					$1,312,988
	Construction					$9,416,091	$14,541,512	$6,988,061		$30,945,664
	Furnishings					$500,000	$250,000	$250,000		$1,000,000
	Commissioning					$50,000	$100,000	$100,000	$51,273	$301,273
										$33,894,397

Q. How have these projected costs been derived?

A. Outside consultants were engaged to develop and prepare a detailed design program and six conceptual design alternatives for the Kalamazoo Service Center project. The alternatives considered various construction elements and building configurations to meet the program requirements. These alternatives were then evaluated by an outside construction management firm to develop project cost estimates for each design alternative. See Exhibit A-75 (QAG-7).

Q. What is the status of the renovation of the Kalamazoo Service Center at the time of this filing?

A. The Company has completed an alternatives analysis to confirm the optimal renovation/reconstruction strategy for the facility. The alternatives analysis including the renovation alternative selected (Alternate Option #1), other alternatives considered, and associated costs are detailed in Exhibit A-75 (QAG-7). The Company has bid and awarded a contract for construction management services and a contract for architectural and engineering design services. Architectural and engineering design work on the project is in progress.

Q. Describe the Parnall P1-3 Renovation project. What is its overall goal?

A. This project includes the engineering, design, procurement, and construction necessary to renovate the existing third floor level of the Parnall 1 Building including fully updating mechanical and electrical systems and space configuration to meet current workforce requirements. The conceptual floor plan can be found at Exhibit A-76 (QAG-8).

Q. What alternatives to the Parnall P1-3 Renovation project did the Company consider?

A. The Company considered the following three alternatives, (1) Do Nothing; (2) Make minimal repairs; and (3) Fully renovate the space. Doing nothing was not a suitable option as the space contained asbestos materials, existing mechanical and electrical systems had exceeded their useful lives, and the space was configured with private offices which did not support a collaborative work environment. Making minimal repairs was also not a suitable option as this alternative would not address the asbestos materials, or space configuration, and the mechanical and electrical systems would continue to fail at an accelerated rate. Full renovation of the space was selected as this allowed full abatement of the asbestos materials, installation of new mechanical and electrical systems which conform to current energy code requirements, and reconfiguration of the space to support a collaborative working environment.

Q. Why did the Company choose to renovate Parnall P1-3?

A. The space contained asbestos materials, existing mechanical and electrical systems had exceeded their useful lives, and the space was configured with private offices which did not support a collaborative work environment.

Q. What benefits will this building provide for customers?

A. This project will provide the following benefits:

- Reduced energy consumption and associated ongoing operating costs; and
- Work environment that supports workplace efficiency.

Q. How much does the Company project to invest in the Parnall P1-3 Renovation project in the bridge period and test year in this case?

A. As shown in Exhibit A-71 (QAG-3), the Company is projecting to invest $332,000 (gas allocation) in the Parnall P1-3 Renovation project in the 21-month bridge period and $0 in the test year.

Q. How have these projected costs been derived?

A. During conceptual design, cost estimates were generated internally to evaluate cost effective alternatives for the project. The project detailed design and construction were bid to multiple consultants and contractors with the lowest qualified bidders selected to perform the work.

Q. What is the status of the Parnall P1-3 Renovation at the time of this filing? Has any work been completed so far, and what work is still remaining to be done?

A. Construction is complete and the project is in closeout.

Q. Please describe the Jackson Dispatch project. What is its overall goal?

A. The Company's Gas Dispatch and Electric Dispatch Centers in Jackson share a common workspace. This shared space is also utilized by temporary storm response personnel during storm response events which results in confusion and miscommunication within and among the dispatch groups and storm response personnel. Company crews, for instance, have reported difficulty communicating with dispatch personnel during storms because of background noise in the Dispatch Center which introduces an unnecessary risk of human performance error. Additionally, the existing HVAC system is unable to support the cooling load of personnel and equipment working in this space, especially during storm response events. Renovation of the Jackson Service Center second floor will provide a new space to house the Gas Dispatch center while leaving the remaining space for dedicated use by Electric Dispatch and storm event personnel. The Electric Dispatch and area for storm response personnel will receive new permanent supplemental cooling to meet the increased demand during full occupancy and storm response events. Modifications will be made to the existing HVAC system to better serve the renovated Gas Dispatch area.

Q. What alternatives to the renovations of this space did the Company consider?

A. The Company considered the following three alternatives: (1) Do nothing; (2) Subdivide existing space; and (3) Reconfigure space for Gas Dispatch and provide permanent supplemental cooling for the Electric Dispatch area and area for storm response personnel. The third option was identified as optimal.

Q. Why did the Company choose to renovate these spaces in the Jackson Service Center?

A. As discussed above, the space shared by the Company's Gas Dispatch and Electric Dispatch centers in Jackson is inadequate for two primary reasons. First, the space as configured is suboptimal as the area often becomes congested (especially during storm response events) resulting in confusion and miscommunication within and among gas and electric dispatch groups and storm response personnel. Second, occupant load within the space exceeds available HVAC system cooling capacity resulting in overheating and severe discomfort among Dispatch personnel. The risk of confusion and miscommunication between Gas and Electric Dispatch personnel and Company crews represents an unnecessary safety risk to both Company crews and the public. For Electric Dispatch, this confusion can delay restoration efforts during storm response events. These facts rule out the "do nothing" option. Subdividing the shared space coupled with the use of temporary cooling equipment is insufficient to properly condition the space and represents a long-term cost. The Company, therefore, opted to reconfigure the space and provide permanent supplemental cooling to meet the variable cooling load in the space.

Q. What benefits will this renovation provide for customers?

A. Renovating this space shared by the Company's Dispatch groups will improve communication between Gas Dispatch personnel and Company crews resulting in improved gas leak response. As is the case for Electric Dispatch personnel, the space as configured is suboptimal and the area often becomes congested (especially during storm response events) resulting in confusion and miscommunication among Gas and Electric Dispatch groups and storm response personnel. Also, occupant load within the space exceeds available HVAC system cooling capacity resulting in overheating and severe discomfort among Gas Dispatch personnel (same as for Electric Dispatch personnel). Improved communication reduces the risk of safety incidents for both Company Gas crews and the public.

Q. How much does the Company project to invest in the Jackson Dispatch project in the bridge period and test year in this case?

A. As shown in Exhibit A-71 (QAG-3), the Company is projecting to invest $419,000 (gas allocation) in the Jackson Dispatch Project in the 21-month bridge period and $25,000 (gas allocation) in the test year.

Q. How have these projected costs been derived?

A. A cost estimate was developed utilizing a multitude of historical cost data from similar projects performed during approximately the last five years.

Q. What is the status of the renovation of the Jackson Dispatch area at the time of this filing? Has any work been completed so far, and what work is still remaining to be done?

A. Phased construction has commenced. The Gas Dispatch Area (Phase 1) has been renovated and is occupied. The Electric Dispatch Area (Phase 2) is under construction and expected to be completed in 2024. The conceptual plans are attached as Exhibit A-77 (QAG-9).

Q. Has the Company invested capital in the Jackson Dispatch renovation thus far?

A. Yes. In the 2022 historical year of this case, the Company invested $246,000 (gas allocation) in the project.

Q. Please describe the Electric Vehicle Charging Infrastructure project. What are its overall goals?

A. As outlined in the direct testimony of Company witness Carveth, the Company has a strategy to electrify portions of its vehicle fleet by purchasing EVs for Company use. As Company witness Carveth discussed, the Company is currently acquiring EVs. To ensure these EVs are available for Company crews to use in serving customers, the Company must construct adequate charging infrastructure at sites where these vehicles will be maintained.

Q. At which Company sites will EVs purchased in the bridge period and the test year be maintained?

A. The Company sites at which EVs purchased in the bridge period and test year will be maintained is outlined in the direct testimony of Company witness Carveth.

Q. How much capital is the Company projecting to invest in the Electric Vehicle Charging Infrastructure project in the bridge period and test year in this case and for what purpose?

A. As shown in Exhibit A-71 (QAG-3), the Company is projecting to invest $186,000 (gas allocation) in the Electric Vehicle Charging Infrastructure project in the bridge period and $138,000 (gas allocation) in the test year. The purpose of this investment is to provide the electric infrastructure upgrades and charging station installations required to support EVs purchased in the bridge period and test year as outlined in the direct testimony of Company witness Carveth.

Q. How were these costs determined?

A. Preliminary cost estimates were developed for electric infrastructure upgrades and charging station installations required to support EVs purchased in the bridge period and test year utilizing historical cost data from similar projects.

O&M Spending Overview

Q. What is included in the projected O&M expenses for Gas Operations Support?

A. The Company is projecting spending $9.525 million in Gas Operations Support for the test year. This spending is allocated between Facilities, Real Estate, and Supply Chain.

Q. What O&M expenses are included in "Facilities," line 1 in Exhibit A-70 (QAG-2)?

A. Facilities work includes items such as maintenance and repair of HVAC systems, miscellaneous building repairs, yard maintenance and snow removal, and daily cleaning or other major scheduled cleaning projects such as windows and carpeting.

Q. What O&M expenses are included in "Real Estate," line 2 in Exhibit A-70 (QAG-2)?

A. Real estate services includes a variety of real estate asset management functions to ensure system integrity and safeguarding of the public. This includes management of all land-related uses of easements and rights of way, including encroachments, third-party requests for use of Company property, landowner requests for modification of easement rights or approval of permission to construct within an easement, as well as management of all corporate facility leases. The group also responds to all requests to sell property or grant easements, leases, or licenses to third parties. Included in real estate services is the records management function that is responsible for maintenance of a land inventory and Geographic Information System mapping for property ownership and rights of way.

Q. What O&M expenses are included in "Supply Chain," line 3 in Exhibit A-70 (QAG-2)?

A. Supply Chain assists with administration support services for Consumers Energy's Security Command Center, IT, Help Desk, Human Resources, Corporate Safety and Health, Fleet, Facilities, Supply Chain, Learning and Development, Real Estate, Travel Services, Operating Maintenance and Construction Jobline, and its Mail Services. This assistance includes intake and scheduling of maintenance work, scheduling of maintenance staff, vendor and contractor management, purchasing of materials and services, document reproduction, and internal mail distribution.

Q. Does this conclude your direct testimony in this proceeding?

A. Yes.

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the application of **CONSUMERS ENERGY COMPANY** for authority to increase its rates for the distribution of natural gas and for other relief.	)))))	Case No. U-21490

REDACTED

DIRECT TESTIMONY

OF

KIRKLAND D. HARRINGTON

ON BEHALF OF

CONSUMERS ENERGY COMPANY

December 2023

Q. Please state your name and business address.

A. My name is Kirkland D. Harrington, and my business address is One Energy Plaza, Jackson, Michigan 49201.

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

A. I am employed by Consumers Energy Company ("Consumers Energy" or the "Company") as a Tariff Analyst in the Rates and Regulation Department.

Q. Please describe your educational background.

A. I received a Dual BBA in Marketing and Management in June 2010 from Northwood University.

Q. Please describe your work experience at Consumers Energy.

A. In March 2013, I was hired by Consumers Energy as a Customer Service Representative within the Company's call center. In May 2017, I accepted a role as a Customer Service Revenue Recovery Assistant within the Energy Assistance department. In November 2018, I accepted a role as a Technical Assistant within Gas Distribution Scheduling where my duties included ensuring proper permitting and safe access to work sites by facilitating coordination between local municipalities and governmental departments. In December 2022, I joined the Rates and Regulation department as a General Rate Analyst in the Rate Administration section. In June 2023 my position title was updated to Tariff Analyst.

Q. Please describe your responsibilities as a Tariff Analyst.

A. My responsibilities include development and implementation of the Company's tariffs. I also perform regulatory research, prepare rate comparisons, and review Michigan Public Service Commission ("MPSC" or the "Commission") orders and legislation.

Q. Have you previously provided testimony before the Commission?

A. Yes. I have filed direct testimony in Case No. U-21378, supporting the tariff exhibit of the Company's proposed voluntary Renewable Natural Gas Program, and Case No. U-21321, supporting the tariff exhibit for the Company's 2024-2025 Energy Waste Reduction Plan.

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

A. The purpose of my direct testimony is to present the Company's proposed tariff language changes to its gas rate schedules and the Transmission Only Transportation Service Rate language as as presented in the direct testimony of Company witness Austin Smith.

Q. Are you sponsoring any exhibits?

A. Yes, I am sponsoring the following exhibits:

Confidential Exhibit A-79 (KDH-1)		Summary of Tariff Changes; and
Confidential Exhibit A-16 (KDH-2)	Schedule F-5	Proposed Tariff Sheets (MPSC No.3 Redlined Version).

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

A. Yes.

Q. Please describe Confidential Exhibit A-79 (KDH-1).

A. Confidential Exhibit A-79 (KDH-1) provides a summary and explanation of the tariff changes proposed for the Company's Gas Rate Book.

Q. Please describe Confidential Exhibit A-16 (KDH-2), Schedule F-5.

A. Confidential Exhibit A-16 (KDH-2), Schedule F-5, provides proposed tariff sheets which detail, in redlined format, all proposed tariff language changes and additions, as well as all price changes proposed by Company witness S. Austin Smith to the Company's Gas Rate Book.

Q. Please explain the changes on Tariff Sheet Nos. D-2.00 through D-2.20

A. These tariff sheets reflect the addition of the Transmission Only Transportation Service Rate categories STT, LTT, XLTT, XXLTT which are represented in Company witness Smith's Exhibit A-16 (SAS-5), Schedule F-3.1.

[redacted]

Q. Please explain the changes on Tariff Sheet Nos. D-9.00

A. This tariff sheet shows the Transmission Only Transportation Service Rate rate categories STT, LTT, XLTT, XXLTT.

Q. Please explain the changes on Tariff Sheet Nos. D-10.00 through D-14.00, E-8.00, E-10.00, and G-5.00.

A. These tariff sheets reflect the price changes proposed in the direct testimony of Company witness Smith.

Q. Please explain the changes on Tariff Sheet Nos. E-13.00 through E-14.00.

A. These tariff sheets describe the Transmission Only Transportation Service Rate which allows eligible customers to move gas though the Company's transmission system to a point of delivery off the Company's distribution system. It describes program rates, billing, term and form of contracts, and early termination details as proposed in Company witness Smith's testimony.

Q. Does this complete your direct testimony?

A. Yes.

S T A T E O F M I C H I G A N

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the application of	)	
CONSUMERS ENERGY COMPANY	)	
for authority to increase its rates for the	)	Case No. U-21490
distribution of natural gas and for other relief.	)	
	)	

DIRECT TESTIMONY

OF

TIMOTHY K. JOYCE

ON BEHALF OF

CONSUMERS ENERGY COMPANY

December 2023

Q. Please state your name and business address.

A. My name is Timothy K. Joyce, and my business address is 17000 Croswell Street, West Olive, Michigan 49460.

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

A. I am employed by Consumers Energy Company ("Consumers Energy" or the "Company") as Senior Strategy Manager in the Gas Engineering and Supply Department.

Q. Please describe your educational background.

A. In 2000, I received a Bachelor of Science Degree in Mechanical Engineering from Purdue University. In 2014, I received a Master of Business Administration Degree from Grand Valley State University.

Q. Please describe your business experience.

A. My professional working career began in 2001 as a Boiler Engineer for Consumers Energy. In this position, I performed boiler inspections and contractor oversight/weld quality during maintenance outages. In 2003, I joined the Operations Department as a Production Engineer at the J.H. Campbell ("Campbell") Plant. In this position, my responsibilities included troubleshooting of equipment, filling in as a shift supervisor and acting as backshift outage manager. In 2007, I accepted a position as Production Lead at Campbell. In this position, my responsibilities included management of day-to-day operations at Campbell Units 1 and 2. In 2008, I moved into a Gas Compression Engineer position for Consumers Energy. My responsibilities included engineering and construction of new compressor stations at White Pigeon Compressor Station ("White Pigeon") Plant 3 and Ray Natural Gas Compressor Station ("Ray") Plant 3.

In 2011, I accepted the position of Project Lead Engineering on the Air Quality Control System project for Campbell Units 1 and 2. This role involved leading the engineering, procurement, installation, and start-up of air emissions reduction equipment on each unit.

In 2016, I moved into my current role of Senior Strategy Manager. In this position, my responsibilities include asset lifecycle oversight, guidance and leadership of the Natural Gas Delivery Plan ("NGDP"), implementation, recovery and verification of results focused on the Company's investment and operation of compression and storage assets.

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

A. Yes. I have recently provided testimony in Case No. U-20322, Case No. U-20650, Case No. U-21148, and Case No. U-21308. In these cases, I have provided testimony and exhibits concerning capital investments for the Company's Gas Compression and Gas Storage assets, operating and maintenance costs for the Company's Gas Compression, Lost and Unaccounted for ("LAUF") Gas, Company Use Gas expenses, Storage Field Inventories and Cost of Gas Sold.

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

A. My direct testimony explains the Company's request for rate relief as it relates to the Company's Gas Compression & Storage ("GCS") assets, and I have divided my direct testimony into five parts:

(i) A description of the Company's GCS assets;

(ii) A description of functions within Gas Compression and Gas Storage;

(iii) A description of Operation and Maintenance ("O&M") expenses for Compression, Cost of Gas Sold and Underground, LAUF and Company Use Gas for the years 2022 through the projected test year (October 1, 2024 through September 30, 2025). (**NOTE:** Storage O&M is addressed by Company witness James P. Pnacek);

(iv) A description of GCS capital expenditures (including the Freedom Compressor Station ("Freedom") upgrade project) for the years 2022 through the projected test year (October 1, 2024 through September 30, 2025) base; and

(v) A description of certain Information Technology ("IT") Projects that support gas compression operations.

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

A. Yes. I am sponsoring the following exhibits:

Exhibit A-80 (TKJ-1)		12 Months Ending September 30, 2025 Gas Compression and Renewable Natural Gas O&M Expenses;
Exhibit A-81 (TKJ-2)		Summary of Actual & Projected Gas O&M Expenses for Lost and Unaccounted for Gas & Company Use Gas for the Test Year 12 Months Ending September 30, 2025;
Exhibit A-82 (TKJ-3)		Calculation of Gas Loss Percentage 2018 through 2023;
Exhibit A-83 (TKJ-4)		Calculation of Allowance for Gas Use and Losses for the Test Year 12 Months Ending September 30, 2025;
Exhibit A-12 (TKJ-5)	Schedule B-5.7	Projected Capital Expenditures Gas Compression and Gas Storage Summary of Actual & Projected Gas Capital Expenditures;
Exhibit A-84 (TKJ-6)		Storage Well Rehabilitation Program Detail; and
Exhibit A-85 (TKJ-7)		Storage Fields Month End Summary.

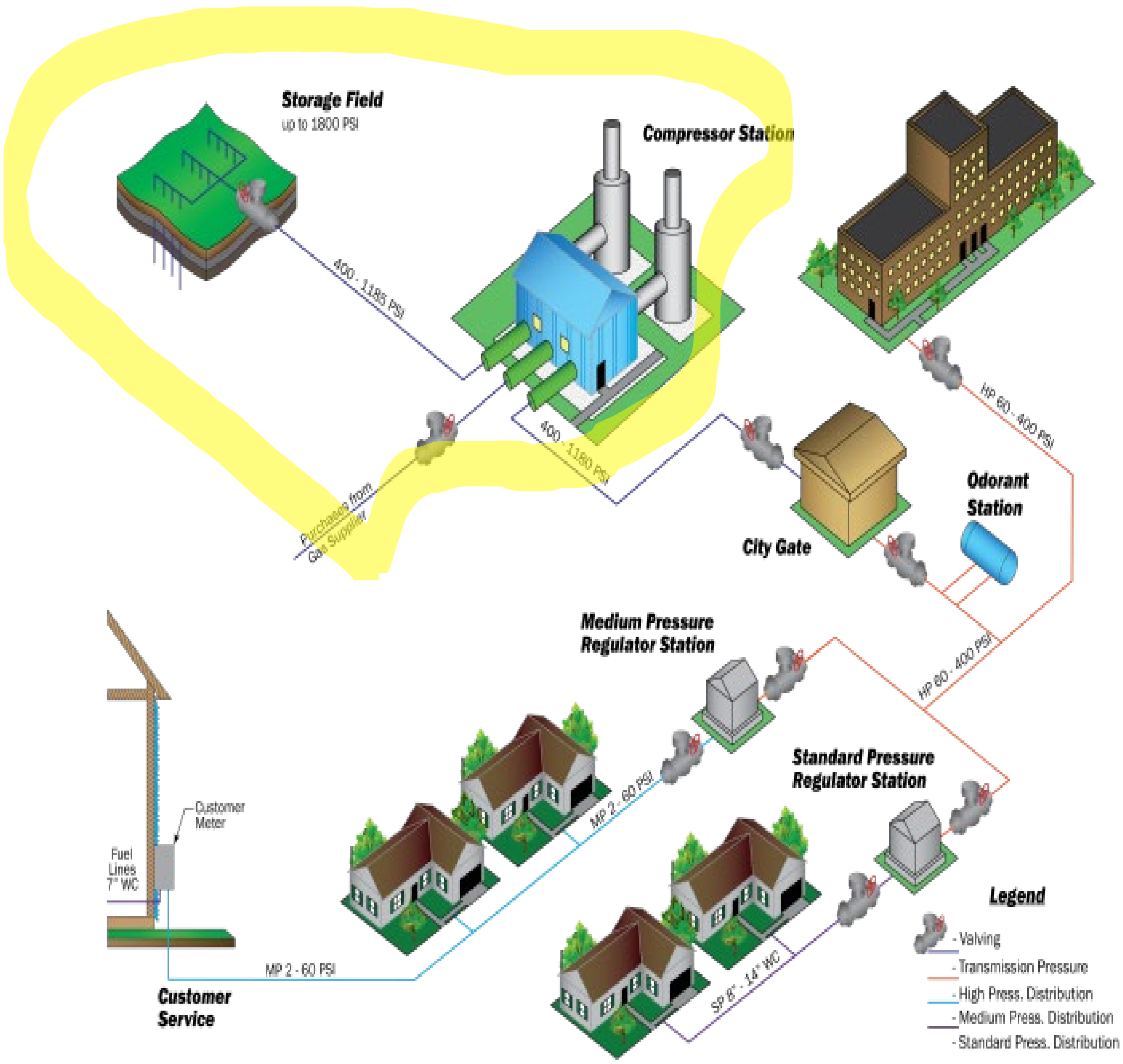
Q. Were these exhibits prepared or assembled by you or under your direction or supervision?

A. The exhibits listed above were prepared either by me or under my direction and supervision.

(i) <u>GCS ASSETS</u>

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

A. The Company operates and maintains eight compressor stations, 15 storage fields, and 826 wells as of January 2023, throughout Michigan's Lower Peninsula. As of October 2023, the compression fleet is comprised of 41 natural gas-fired engines which generate 157,893 Brake Horsepower ("BHP"), providing the pressure necessary to move gas in and out of the storage fields and to receive supply from interstate pipeline sources onto the Company's transmission pipeline system. The transmission pipeline system connects the gas supplies to Consumers Energy's storage fields, gas distribution system, and other customer loads. In the diagram below, the Storage and Compression systems are inside the yellow highlighted section.



The Company's storage fields are used to balance the difference between the incoming system supplies and customer demand on a continuous, real-time basis. The storage fields are naturally occurring porous rock formations that are located deep underground. These rock formations hold natural gas, much like sponges hold water, and have a total working gas volume of 154 BCF. Consumers Energy purchases 100% of the natural gas it provides to customers. Natural gas, which is placed in storage, flows through one or more of the Company's numerous wells. The Company's GCS fleet is comprised of the following:

Compressor Stations:

Name	Location	Number of Units	Horsepower (BHP)
Freedom	Manchester, MI	5	18,750
Muskegon River	Marion, MI	8	37,776
Northville	Northville, MI	4	10,800
Overisel	Hamilton, MI	4	10,800
Ray	Armada, MI	5	23,675
St. Clair	Ira, MI	6	27,282
White Pigeon	White Pigeon, MI	8	27,775
Huron	Sebewaing, MI	1	1,035

Gas Storage Fields:

Type	Storage Field Name	Working Gas Volume (Bcf)*	Base Gas Volume (Bcf)*	Total Gas Volume (Bcf)*	Number of Wells
Base	Winterfield	25.30	47.00	72.30	258
	Overisel**	25.50	27.50	53.30	152
	Salem	11.60	18.90	30.50	71
	Cranberry	11.00	17.20	28.20	138
	Riverside	1.50	7.50	9.00	51
Intermediate	Hessen**	13.50	3.48	16.98	24
	Puttygut	9.50	5.10	14.60	24
	Four Corners	2.39	1.39	3.78	6
	Swan Creek	0.42	0.23	0.65	1
	Ray	48.10	17.27	65.37	62
Needle Peaker	Ira	2.00	4.25	6.25	15
	Lyon 29	1.23	0.95	2.18	3
	Lenox	1.20	2.03	3.23	11
	Lyon 34	0.70	0.66	1.36	5
	Northville Reef	0.50	0.72	1.22	5

NOTE: All gas volumes are in MMcf at 14.73 psi dry pressure base .

***A review of recent withdrawal seasons and reservoir integrity resulted in a 1 and 2.5 BcF working gas increase at Overisel and Hessen, respectively. This does not change the total gas volumes of each reservoir.*

(ii) <u>GAS COMPRESSION AND STORAGE</u>

<u>Gas Compression</u>

Q. Please describe the primary functions of gas compression.

A. Gas compression is responsible for the safe operation, maintenance, and performance of the Company's natural gas-fired engines. These units provide the pressure necessary to move gas in and out of the storage fields, to move gas from interstate pipeline sources onto the Company's transmission pipeline system, and ultimately, to move the natural gas to the city gate facilities feeding distribution systems that transport gas to the Company's customers.

Q. Do maintenance costs vary by individual compression engine(s)?

A. Yes, maintenance costs vary by individual compression engine(s). The Company's compression engines vary in age, size, type, and design and encounter varying operating conditions.

Q. Is it common to have size, type, design, and operating differences?

A. Yes. Consumers Energy is not unique in that its fleet contains units of different size, type, and design. The compression engines used for storage will typically encounter a wider range of operating pressures and flow rates than engines used to boost pressure on the transmission system.

Q. Please describe the work completed in a natural gas compressor engine maintenance inspection.

A. The frequency of compressor engine inspections is based on operating hours, and consists of disassembling, inspecting, and cleaning the different components of the engine. During the inspection, worn or damaged parts are repaired or replaced to specific tolerances. Cost can range from $25,000 to $75,000 per inspection, depending on the size and model of the unit. Additional costs can occur if parts are found to be worn and require replacement before resulting in random outages at inopportune times when needed to meet system demand.

Q. How does Consumers Energy measure the success of its Gas Compressor Engine Maintenance Program?

A. The Company measures Random Outage Rate ("ROR"). The Company has also developed another metric, Gas Flow Deliverability ("GFD"). The deliverability metric was developed to measure the ability of the gas system to reliably achieve targeted flow rates, and to identify and assess potential system/customer risk. ROR continues to be used to measure engine/compressor performance. The additional GFD metric allows all compressor station and system equipment performance to be measured. Use of the new metric began in 2019 and is used in development of the compressor station work plans.

Q. What is the Company's current ROR, and how does it compare to previous years?

A. The table below shows the Company's ROR from 2019 through September 2023.

Table 1: System ROR

Year	System ROR
2019	28.5%
2020	17.5%
2021	15.6%
2022	8.4%
2023 (YTD Sept)	12.1%

Table 2: Freedom, Ray and White Pigeon Station ROR

Year	Freedom Station ROR	Ray Station ROR	White Pigeon Station ROR
2019	21.8%	38.2%	21.5%
2020	21.7%	17.7%	25.5%
2021	27.0%	16.5%	25.1%
2022	13.2%	10.6%	9.2%
2023 (YTD Sept)	7.1%	21.1%	4.8%

Q. What has contributed to the improved ROR performance in 2022-23 and what is needed for the Company to be able to achieve and maintain its engine performance?

A. All equipment repairs have been completed at Ray after the 2019 fire. The Freedom upgrade project is completed, and all legacy horsepower have now been removed from service, as detailed later in my testimony. Retirement of the units at White Pigeon and Ray occurred in 2021. The effort to optimize the compression fleet has provided improved performance of the newer units and removal of the lower performing legacy units, which has netted an improvement in ROR for 2022-23.

To improve the ROR of the remaining compression fleet and, consequently, reduce downtime and overall maintenance costs, the Company will enhance maintenance plans and practices to achieve more efficient preventative programs and eliminate costly reactive events.

Q. Please describe the Company's objectives for gas compression assets.

A. The Company's objective for its gas compression assets is to realize the most value out of the Company's substantial storage capacity in terms of resilience and buffering summer/winter price fluctuations. Continually improving the safety of compression assets and reducing operational risks is critical. Beginning in 2010, the Company made significant progress transforming the compression fleet from 1950s technology to modern, efficient, and clean running equipment. In recent history, some of the older compression fleet has not been reliable and starting up the newly installed equipment has required learning for the Company and its equipment suppliers. Based on this experience, Consumers Energy is planning to do the following:

- Improve reliability, operating flexibility, and resiliency of the compression fleet.
- Improve monitoring of operating parameters to better understand equipment health and to optimize maintenance work management.
- Implement lessons learned from the 2019 Ray Compressor Station ("Ray") fire incident to improve resilience of the Ray station as well as overall system resilience.
- Optimize the compression fleet, which may include addition of certain equipment for reliability or resiliency and retire antiquated compression assets that do not positively affect the Company's plan to provide safe, reliable, affordable, and clean energy.

Q. Does the NGDP discuss gas compression assets?

A. Yes, gas compression is addressed in Section IV of the Company's NGDP, which is provided as Exhibit A-43 (NPD-1) by Company witness Neal P. Dreisig.

<u>Gas Storage</u>

Q. Please describe the primary functions of gas storage engineering.

A. Gas Storage Engineering has responsibility for the integrity, maintenance, and performance of the Company's 15 storage fields and 826 wells. This includes storage well maintenance and well logging and compliance with well integrity regulations. Further details about gas storage engineering O&M expenses are included in Company witness Kristine A. Pascarello's testimony.

Q. Please provide further insight into well maintenance.

A. Well maintenance is comprised of many different programs and has been the topic of media attention in recent years with the Aliso Canyon event. Well logging is one of the primary components of well maintenance. *Well logging* is an industry term that describes a method used to help assess storage well integrity. Storage well integrity is a critical component to ensuring public safety.

Q. Please provide more detail on well logging.

A. Well logging includes the use of gamma ray-neutron log for identification of gas accumulation behind casings, corrosion logs for internal and external casing corrosion, and cement bond logs to assess integrity of cement between the casing, surrounding rock, or additional casings. Additionally, well rehabilitation work is performed in conjunction with well logging to mitigate the formation of skin damage. *Skin damage* is a term used to describe the reduction in the ability of the reservoir rock to store and deliver gas. Rehabilitation removes solids, scale build-up, and compressor oils in the well that accumulated during the normal process of injecting and withdrawing gas from storage. By removing this build-up, the gas moves more efficiently and reduces the risk of moving debris into the compressors, thereby increasing safety and extending the life of the assets.

Q. Do storage well integrity regulations currently exist?

A. Yes. On December 19, 2016, the Department of Transportation's Pipeline and Hazardous Materials Safety Administration ("PHMSA") published in the Federal Register an interim final rule ("IFR") that revises the federal pipeline safety regulations to address critical safety issues related to downhole facilities, including wells, wellbore tubing, and casing, at underground natural gas storage facilities. This IFR was in response to the June 22, 2016, enactment of the Protecting our Infrastructure of Pipelines and Enhancing Safety ("PIPES") Act of 2016 that included a requirement for PHMSA to set federal minimum safety standards for underground natural gas storage facilities. Requirements included in the IFR were amended to final rule by PHMSA on February 12, 2020.

Q. Did PHMSA set federal minimum safety standards?

A. Yes. PHMSA published the underground natural gas storage facilities rule (49 Code of Federal Regulations ("CFR") 192.12) which incorporates by reference the requirements within the American Petroleum Institute ("API") Recommended Practice ("RP") 1171.

Q. Is Consumers Energy compliant with the standards set forth in 49 CFR 192.12?

A. Yes. Consumers Energy has reviewed the requirements outlined in 49 CFR 192.12 and the applicable API RP 1171. The Company developed procedures governing operations, maintenance, integrity demonstration and verification, monitoring, threat and hazard identification, assessment, remediation, site security, emergency response and preparedness, and recordkeeping consistent with the requirements of API RP 1171, sections 8, 9, 10, and 11 by January 18, 2018, for all existing underground natural gas storage facilities. Integrity assessments of the underground storage wells began in 2017 to support the anticipated compliance timeframe, for completing all risk management activities as required in API RP 1171. The compliance date has now been set for March 2027.

Q. Has PHMSA performed an audit of the Company storage system?

A. Yes. In May 2019, PHMSA performed a program overview audit, followed by field audits, on six gas storage fields and the associated site-specific programs. The audit focused on Sections 8 through 11 of API RP 1171. In 2020, there were field specific audits at the Four

Corners, Swan Creek, Hessen, Ira, and Puttygut fields. In 2021, the MPSC jointly with the Michigan Department of Environment, Great Lakes, and Energy performed field specific audits at the Riverside, Lyon 34, Lyon 29, and Northville Reef.

In 2023 (based on a 4-year cycle) another program audit with field audits, is being performed by the MPSC.

Q. What was the result of the 2019 audits?

A. The Company created a Detailed Action Plan based on PHMSA recommendations of best industry practice. Topics outlined in the plan include: Risk Management for Gas Storage Operations, Integrity Demonstration, Verification, Monitoring Practices, Site Security and Safety, Site Inspections, Emergency Preparedness and Response, and Procedures and Training.

Q. Were any changes made to the Well Rehabilitation Program based on the PHMSA 2019 audit recommendations?

A. Yes. PHMSA recommended the wells in the Riverside field be addressed by the program (risk priority as identified in the risk analysis) until the plan to discontinue operation of the field is executed. As a result, the Company added wells to the 2019 and future-year Well Rehabilitation Program work scopes. PHMSA also recommended the addition of annular piping to surface where casing pressures will be recorded and monitored, as per the requirement in API RP 1171. These items are now being addressed by the program as they are encountered, which has an impact on the average cost per well. The Company established a new annulus pressure monitoring program for 2022 and future years to address compliance, including the wells already rehabilitated in 2017 and 2018.

Q. Is the Company projecting O&M expenses related to well logging in this case?

A. Yes. Well logging O&M expenses are sponsored by Company witness Pascarello in the well re-assessment section.

Q. Does gas storage have additional responsibilities?

A. Yes, gas storage is also responsible for the gas storage field inventory verification process.

Q. Please describe the gas storage field inventory verification process.

A. As a prudent operating practice and following the regulatory requirements of API RP 1171 as referenced in 49 CFR 192.12, Consumers Energy performs storage field pressure surveys at the conclusion of each injection cycle (usually August through November), and each withdrawal cycle (usually March through June). Storage well pressures are collected, the average field pressure is determined, and the results are plotted against the metered volumes. Plotting storage field pressure and inventory data provides a means of monitoring and trending storage field performance over time. It is through this process that the inventory balances at the storage fields are identified for adjustment.

Q. Why is the performance of storage field inventory verification a prudent practice?

A. Verification of storage field inventory after each injection and withdrawal cycle provides important data used to monitor the current condition of the storage reservoir. In addition, storage field inventory verification provides a means of determining flow meter measurement accuracy, and whether losses between the transmission and storage systems may be occurring as a result of valve leakage. Without inventory verification, there is the potential for gas to have migrated out of the storage reservoir, which would pose potential risk to public safety. In addition, if inventory is not verified and a leakage were to occur unknowingly, customers could be at risk of paying for gas that is lost.

Q. What are the recent results from the gas storage inventory verification process?

A. The storage fields have experienced deviations from the accounting booked figures. The Company typically adjusts gas storage inventory based on a deviation occurring for three consecutive years (considered long-term). Routine changes in operating parameters during a given injection or withdrawal season may cause short-term storage field pressure variations. These short-term pressure variations may cause the natural gas to migrate deeper into the reservoir rock formation, temporarily impacting the inventory survey results. Company personnel have investigated the integrity of these fields and believe most of the inventory adjustment is attributed to metering accuracy limitations or valves not sealing properly. The storage field inventory adjustment is shown in Exhibit A-82 (TKJ-3).

Q. Why does the storage inventory deviation occur?

A. A common cause of the deviations and subsequent storage field inventory adjustments can be valves not sealing properly. As part of the pressure survey work each spring and fall, the sealing capability of the valves used to isolate the storage field are inspected. The primary cause of valve leakage, as with the field meter, is debris affecting the sealing mechanisms in the valves. In addition, the electrical or hydraulic mechanical operators used to open and close the valves can go out of alignment, not allowing the valve to fully close. When storage field isolation valves are found to be not sealing, the valves are adjusted or repaired.

Q. Please describe the Company's objectives for gas storage assets.

A. The gas storage system today includes 15 storage fields totaling approximately 154 billion cubic feet of gas storage capacity. Storage assets play an important role in customer affordability, enabling the purchase and storage of gas when prices are lower, and delivery of that gas in the winter. On average, storage has supplied approximately 50% of customer gas deliveries during winter (November through March) and up to approximately 80% on peak days. Storage also allows Consumers Energy to store or withdraw gas throughout the day to reconcile the difference between customer demand and the fixed pipeline supply.

As part of the NGDP (and in view of the PHMSA Storage Audit based on API RP 1171), the Company ran an initial assessment on four of the low-cyclic fields with the results showing the need to consider the retirement of at least one storage field at this time. Based on the outcome of this initial assessment, Consumers Energy has evaluated retirement and optimization of its storage fields over time based on certain factors like customer load, market price changes over time, increasing operating costs, reliability, and total cost to customers. The Company has made the decision to move forward with the retirement or potential sale of Riverside storage field; further details and projected expenses are outlined later in my testimony. With the remaining storage portfolio, Consumers Energy will remain focused on reliable operation, increasing resiliency, while optimizing deliverability.

Q. Does the NGDP discuss gas storage assets?

A. Yes. Gas storage is addressed in Section IV of the Company's NGDP, which is provided as Exhibit A-43 (NPD-1) by Company witness Dreisig.

Q. What value do customers receive from the Company's GCS assets?

A. GCS assets support the Company's ability to ensure adequate supplies of natural gas are available for customers when needed. They are also an important foundation to maintaining affordable prices, as they allow the Company to take advantage of favorable seasonal market conditions, while procuring adequate supplies in advance to meet customers' needs. Finally, storage fields are critical to mitigating winter price cycles, summer outage schedules, and maintaining supply during unexpected supply interruptions.

(iii) O&M EXPENSES FOR COMPRESSION, COST OF GAS, LOST AND UNACCOUNTED FOR AND COMPANY USE

Q. Please describe Exhibit A-80 (TKJ-1).

A. Exhibit A-80 (TKJ-1) identifies the 12 Months Ending September 30, 2025, Gas Compression and Renewable Natural Gas O&M Expenses. Specifically:

- Page 2, column (a) identifies each O&M expense category;
- Page 2, column (b) identifies the Actual 2022 Gas Compression O&M expense as $23,830,000;
- Page 2, column (c) identifies the Projected 2023 Gas Compression O&M expense as $18,279,000;
- Page 2, column (d) identifies the Projected 2024 Gas Compression O&M expense as $17,039,000; and
- Page 2, column (e) identifies the Projected test year Gas Compression O&M expense as $17,039,000.

Table 3: Compression O&M

	Projected O&M Expenses				
	(a)	(b)	(c)	(d)	(e)
			Projected		
Line No.	**Description**	**12 mos. Ended 12/31/2022**	**12 mos. Ending 12/31/2023**	**12 mos. Ending 12/31/2024**	**10/1/2024 - 9/30/2025**
1	**Gas Compression**	$ 21,939	$ 19,132	$ 17,039	$ 17,039
2	**Compression Rebuilds**	1,891	(853)	-	-
3	**Renewable Natural Gas**	-	-	-	-
4	**TOTAL O&M**	**$ 23,830**	**$ 18,279**	**$ 17,039**	**$ 17,039**

Q. Please discuss the 2022 Actual O&M expenses incurred by the Company for Gas Compression.

A. The 2022 Actual O&M expenses were taken from Consumers Energy's internal accounting records.

Q. Please explain how the 2023, 2024, and projected test year O&M expenses were calculated.

A. Consumers Energy tracks the history and future maintenance needs of each station. Once costs to reliably operate and comply with the Michigan Gas Safety Code are prioritized, Business Services-Portfolio Planning, with the support and input from Engineering and Asset Strategy, evaluates the maintenance plans required to maintain and improve the condition of the plant. Using this information, a preliminary plan is prepared, reviewed (to ensure high-priority issues are addressed and adequate resources and funding are available), and approved by management. The overall objective is the safe, reliable, and cost-effective operation of the Compression operations.

O&M costs projected in Exhibit A-80 (TKJ-1) were developed by evaluating a station's operating history and are broken into two categories: "labor" and "non-labor." Labor is the primary component and has a predictable increase. Non-labor expenses are also predictable and include items required to operate and execute a workplan to meet code requirements, while meeting operational performance to fulfill customer demand. These items include, but are not limited to: (i) fuel, oil and glycol for equipment and vehicles; (ii) materials; (iii) tools; (iv) cleaning supplies; (v) security; and (vi) road and grounds maintenance. Please note that Gas Storage Operations expenses are addressed by Company witness Pnacek. The test year spending was calculated using a weighted average of the

2024 and 2025 forecast. The 2024 calendar year was weighted approximately 38% and 2025 calendar was weighted approximately 62%. This weighting reflects historical spending timing using recent historical actuals information.

Q. Please explain page 4 of Exhibit A-80 (TKJ-1).

A. Exhibit A-80 (TKJ-1) presents the amounts of the O&M expenses by applying either an inflation rate or a merit increase rate, or both to historical O&M expense. Column (b) shows the historical O&M expense. Column (c) shows the amount of the historical when an inflation rate or merit increase rate is applied to it. Columns (e) and (g) show the amounts when an inflation rate or merit increase rate is applied for each bridge period, respectively. Columns (d), (f), and (h) show the merit and inflation amounts for each respective period. Amounts that were projected using other methods are included in column (i). Column (j) is the projected test year O&M and is the sum of columns (b), (d), (f), (h), and (i); column (j) is aligned with the Company's projected expenses for each sub-program for the test year, as shown in Exhibit A-80 (TKJ-1). Therefore, column (i) represents the increase in O&M expenses that is not due to inflation; in other words, this represents where O&M expenses are changing due to some other factor than inflation.

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

A. No, there are not. The direct testimony and exhibits of Company witness Amy M. Conrad contain the Gas Transmission and Distribution EICP O&M expense dollars.

Q. Please explain why the projected test year O&M expenses proposed in Exhibit A-80 (TKJ-1) are reasonable.

A. This level of O&M expense allows the Company to provide reliable service by operating and maintaining its Compression equipment to move gas into and out of storage and throughout its system to meet the needs of customers.

COST OF GAS AND COST OF GAS STORED UNDERGROUND

Q. Please describe Exhibit A-85 (TKJ-7).

A. Exhibit A-85 (TKJ-7) is a listing of the Company's September 2022 through September 2025 underground gas storage volumes and dollars.

Q. Would you briefly explain the background for Exhibit A-85 (TKJ-7)?

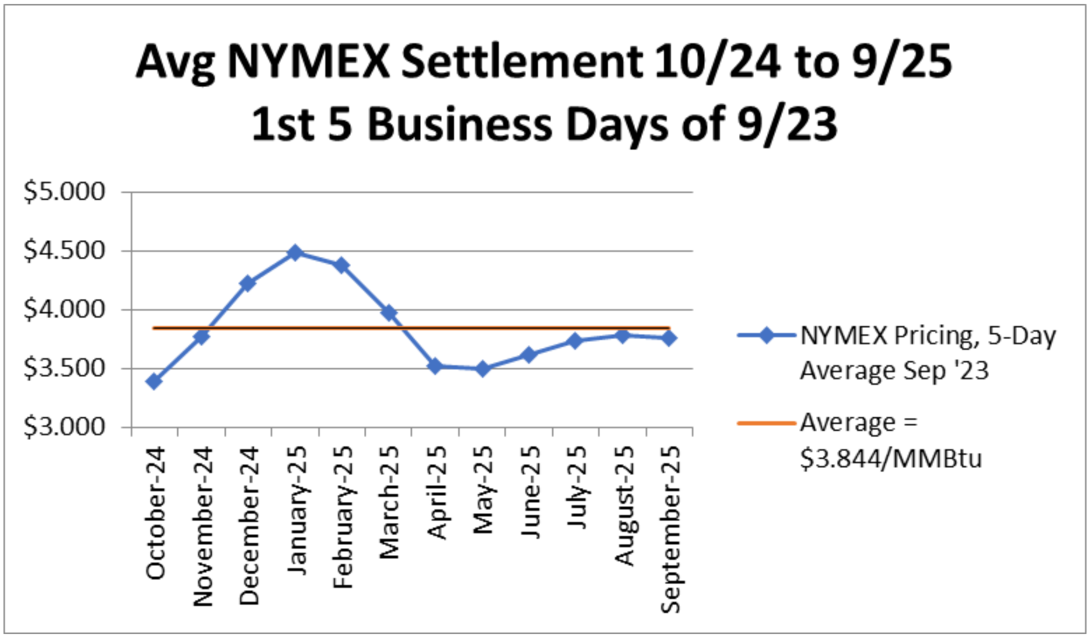
A. Yes. Exhibit A-85 (TKJ-7) reflects the end of the month underground gas storage volumes and dollars that result from the Company's natural gas purchases for its Gas Cost Recovery ("GCR") and Gas Customer Choice ("GCC") customers. The costs and volumes reflect the Company's existing supply and transportation contracts for the historical period, as well as those of the GCC suppliers. Projected supply sources and prices are used for the future periods.

Q. What is the Company's projected test year 13-month average volume and cost of gas in storage, as set forth on Exhibit A-85 (TKJ-7)?

A. Through September 2025, the Company is projecting a 13-month average cost of gas in storage of $3.571/Mcf ($463,500,225/129,781,253 Mcf).

Q. What gas prices were assumed for October 2024 through September 2025 in developing your Exhibit A-85 (TKJ-7)?

A. The average New York Mercantile Exchange ("NYMEX") settlement prices for October 2024 through September 2025, as of the first five business days of September 2023, were used. These NYMEX natural gas prices, as shown in the graph below, averaged $3.844/MMBtu for October 2024 through September 2025.



For the October 2024 through September 2025 GCR requirements (196,293,966 Mcf), 0% has been purchased at a fixed price, therefore 100% of the GCR requirements would be subject to the NYMEX average.

Q. What is the Company's projected average cost of gas sold for October 2024 through September 2025?

A. The Company is projecting an average cost of gas sold for October 2024 through September 2025 of $3.864/Mcf ($875,508,654/226,611,332 Mcf). The Company's cost of gas sold reflects locational pricing differences between NYMEX (Henry Hub) and other supply locations (basis), transportation costs, unused reservation charges, and the GCR accounting treatment of net system uses. The projected average cost of gas sold is determined by including the costs and volumes associated with purchase requirements and net storage activity during the period, and thus reflects the same variables and assumptions relied on to calculate ending inventory values.

Q. Please provide additional detail about the average cost of gas sold and cost of gas stored underground.

A. Both the average cost of gas sold and cost of gas stored underground reflect the natural gas supply and transportation contracts in place within the historic period for GCR and GCC supply. The Company's existing supply and transportation contracts are planned to leverage storage and system investments in today's gas market to provide customers with safe, reliable, and affordable natural gas service pursuant to the Company's NGDP.

The cost of gas stored underground is used within the Company's projected test year working capital included in Company witness Heather L. Rayl's Exhibit A-12 (HLR-34), Schedule B-4. The average cost of gas sold of $3.864/Mcf is used in the calculation of the Company's revenue requirement and to price out Company Use and LAUF gas volumes supported later in my testimony.

<u>LAUF Gas</u>

Q. Please explain LAUF gas as shown on Exhibit A-81 (TKJ-2), line 1, column (b).

A. LAUF gas is the loss or gain of gas volumes calculated as the difference between the volumes delivered into the transmission and distribution system less the volumes delivered out of those systems. Factors such as gas leaks, customer billing issues, customer theft, meter and measurement accuracy, and gas vented for operational, maintenance, and safety purposes all contribute to the causes of LAUF gas volumes.

Q. Please describe the LAUF expenses that are projected for the test year.

A. The test year expenses related for LAUF gas are calculated based on a five-year average of actual LAUF volumes multiplied by the Company's projected commodity cost of gas. Projected LAUF expenses can be found on Exhibit A-81 (TKJ-2). As shown on that exhibit (line 1, column (c)), the test year projected LAUF expense level is $13,483,000. The 2022 historical year amount was $27,492,000 as shown in Exhibit A-81 (TKJ-2), (line 1, column (b)).

Q. Please explain Exhibit A-81 (TKJ-2).

A. This exhibit identifies the projected changes from the historical 2022 amount for LAUF expenses to the test year period. The test year LAUF amount was calculated using the methodology consistent with the July 31, 2017 Order in Case No. U-20322, updated with the most recent five-year average Gas Loss percentage and expected test year cost of gas expense, as provided earlier in my direct testimony. Additionally, this exhibit contains the Company Use Gas projected expenses for the test year. Company Use Gas will be discussed later in my direct testimony.

Q. Please explain Exhibit A-82 (TKJ-3).

A. This exhibit demonstrates the calculation of the most recent five-year average Gas Loss percentage (line 6, column (g)) of 1.66%. This percentage, when applied to test year throughput levels, determines the expected LAUF and Company Use Gas volumes during the test year.

Q. Please explain Exhibit A-83 (TKJ-4).

A. This exhibit shows the calculation of the projected test year amount of LAUF expense (line 14, column (h)) with the methodology adopted in Case No. U-20322. The test year throughput level and the updated Gas Loss percentage previously discussed have both been used to determine LAUF volumes and the associated expense levels. In addition, as shown on line 11, the Allowance for Use and Losses percentage, also known as the Gas-in-Kind ("GIK") percentage, has been updated to reflect test year projections of 2.45%.

Q. Is the level of LAUF expense the Company is requesting reasonable?

A. Yes. The Gas Loss average is based on actual losses on the gas transmission and distribution system over the past five years. The MPSC has consistently recognized a five-year average of Gas Losses to set LAUF volumes, and the Company continues to use that same methodology, updated to reflect the most recent data.

Q. Why have you included the net storage inventory adjustments in the LAUF figures as noted on Exhibit A-82 (TKJ-3)?

A. In Case Nos. U-18124 and U-20322, the Commission approved inclusion of storage inventory adjustments in the period in which they are recognized by the Company, within the five-year line loss calculation.

Q. How does the Company determine its storage inventory adjustments?

A. The Company's storage inventory adjustments are determined through the gas storage field inventory verification process. This process is described in the *Gas Storage* section of my direct testimony.

Q. What specific actions does the Company take to monitor and mitigate LAUF gas?

A. The Company has ongoing actions to monitor and reduce LAUF gas. Some of these actions include:

- A gas measurement team that primarily focuses on assuring (i) measurement accuracy and (ii) that industry practices are maintained relative to LAUF related issues. Company personnel actively participate on the American Gas Association Transmission Measurement Committees, discussing various measurement issues;

- Measurement personnel audit and witness other Company and third-party personnel performing the regularly scheduled calibration/inspection of metering and gas quality equipment around the state. This helps ensure valid measurements and relevant procedures are followed, and also allows for identification and subsequent correction of any equipment/calibrations/ inspection-related issues;

- The Company utilizes a gas measurement system called Flow Cal monitored by the gas measurement team and field personnel to validate actual measured flows captured by the Company's data acquisition system—known as Supervisory Control and Data Acquisition; and

- The Company reviews compressor stations and high flow city gates for fugitive leaks through the use of infrared cameras and high flow analyzers. Identified leaks will be prioritized and repaired, reducing LAUF gas at those sites.

<u>Company Use Gas</u>

Q. Please describe the Company Use Gas expenses shown on Exhibit A-81 (TKJ-2), line 2.

A. These expenses are for the natural gas fuel used to run the compression and other equipment used on the transmission and storage system. The largest single use is for fueling the engines at the compressor stations and the gas heaters at the city gate stations. The total cost of fuel gas used is reduced by credits received from transportation suppliers. These suppliers provide GIK to Consumers Energy based on a percentage of their deliveries into the system. Company Use Gas also includes volumes of gas vented or otherwise released for which the Company has knowledge and which the Company has written off.

Q. What level of expense for Company Use Gas are you proposing in this case?

A. As set forth on Exhibit A-81 (TKJ-2), line 2, column (c), the Company Use Gas expense for the test year is projected to be \$6,465,000. The calculation supporting this value can be found on Exhibit A-83 (TKJ-4).

Q. Why is there variability in the test year amounts for LAUF and Company Use Gas from the 2022 actual amounts?

A. In Case No. U-18124, the Commission ordered the Company to apply GIK transportation volume offsets to LAUF and Company Use Gas volumes on a percentage basis based upon the program volumes. The Company has historically offset only Company Use Gas volumes with GIK volumes, and its accounting system is currently configured to record GIK volumes against Company Use Gas volumes. Thus, the 2022 amounts are shown as recorded in the Company's internal accounting records. The test year amounts are reflective of the methodology directed in Case No. U-20322.

(iv) <u>GCS CAPITAL EXPENDITURES</u>

Q. What are the major drivers in determining capital expenditures for GCS?

A. The Company has made significant investments in upgrades for improved system reliability, deliverability, system integrity, safety, and customer service. These investments, including the Freedom upgrade, allow the Company to fully use its compression and storage facilities to provide continuous reliable service to customers.

Q. Please describe Exhibit A-12 (TKJ-5), Schedule B-5.7.

A. This exhibit presents the capital expenditures for GCS from the year 2022 through the projected test year. The expenditures are grouped on page 2 by: Freedom upgrade, Compression Sites, Storage Fields, Storage New Wells (line 14), Well Rehabilitation (line 15), Storage Pipeline Replacement (line 16), Well Data Acquisition (line 17), Riverside Field Retirement (line 18), and Safety Valve Installation (line 19).

Q. What is the Company's projected level of capital spending?

A. The Company's rate relief request in this case reflects capital spending on projects for its gas compression and storage sites of $118.9 million for 2022 (Actual), $121.9 million for the 12 months ending December 31, 2023 (Projected), $148.8 million for the nine months ending September 30, 2024 (Projected), $270.6 million for the 21 months ending September 30, 2024 (Projected), and $220.4 million for the 12 months ending September 30, 2025 (Projected Test Year). The table below, from page 1 of Exhibit A-12 (TKJ-5), Schedule B-5.7, shows the Compression and Storage capital expenditures I am sponsoring in this docket.

Table 4: Compression and Storage Capital Expenditures

	(a)	(b)	(c)	(d)	(e)	(f)
		Capital Expenditures				
		Historical	Projected Bridge Year			Projected Test Year
Line No.	Program Description	12 Mos Ended 12/31/2022	12 Mos Ending 12/31/2023	9 Mos Ending 9/30/2024	21 Mos Ending 9/30/2024	12 Mos Ending 9/30/2025
1	Freedom Upgrade Project	13,567	7,600	401	8,001	-
2	Compression	39,968	42,314	42,934	85,248	59,032
3	Storage	10,896	5,742	23,802	29,544	33,067
4	New Well	10,164	13,070	14,572	27,641	30,456
5	Well Rehabilitation	34,985	35,512	23,873	59,385	32,852
6	Storage Pipeline Replacement	6,418	5,159	8,087	13,246	22,404
7	Well Data Acquisition	300	376	226	601	3,566
8	Riverside Field Retirement	2,571	12,114	33,318	45,432	37,067
9	Safety Valve Installation	-	-	1,540	1,540	1,938
10	**Total Capital Expenditures**	**118,868**	**121,886**	**148,754**	**270,639**	**220,382**

Q. Please identify the capital expenditures projected for the Freedom Compression Station.

A. Exhibit A-12 (TKJ-5), Schedule B-5.7, page 2, lines 1 and 2, identify the total capital expenditures for the Freedom Compression Station. The expenditures identified on line 1 are for the Freedom upgrade project. The details of the Freedom upgrade project are described later in my direct testimony. The expenditures on line 2 are for projects that are separate from the upgrade project. In 2022, costs were incurred for the upgrade project. In 2023 through 2025, costs will be incurred for the completion of the upgrade project.

Q. Please identify the capital expenditures projected for the Muskegon River Compression Station.

A. Exhibit A-12 (TKJ-5), Schedule B-5.7, page 2, line 3, identifies the total capital expenditures for the Muskegon River Compression Station. In 2022, costs were incurred for fire gate valve replacements, replacement of dehydration system piping and heat exchangers, and a jet installation project to allow for complete and timely withdrawal of gas from the storage fields after the retirement of Plant 3 units. In 2023 through 2025, examples of projected costs include: a unit overhaul, installation of engine exhaust emission control equipment for the engines to comply with the Federal Good Neighbor Plan[1] requirements, and a closed-loop cooling project that will eliminate the need to use Muskegon River water for equipment cooling.

[1] https://www.govinfo.gov/content/pkg/FR-2023-06-05/pdf/2023-05744.pdf

Q. Please identify the capital expenditures projected for the Northville Compression Station.

A. Exhibit A-12 (TKJ-5), Schedule B-5.7, page 2, line 4, identifies the total capital expenditures for the Northville Compression Station. In 2022, costs were incurred for the completion of electrical system upgrade, and firegate valve replacements. In 2023 through 2025, examples of projected costs include: electrical system upgrades, engine controls upgrades, and engine exhaust emissions controls to comply with the Federal Good Neighbor Plan, which all support the safe, reliable, and regulatorily compliant operation of the station.

Q. Please identify the capital expenditures projected for the Overisel Compression Station.

A. Exhibit A-12 (TKJ-5), Schedule B-5.7, page 2, line 5, identifies the total capital expenditures for the Overisel Compression Station. In 2022, the Company incurred costs for completion of the dehydration system and valve replacements, and the unitized cooling project. In 2023 through 2025, examples of projected costs include: unitized cooling installation, station control upgrades, lube oil extractor installation and engine exhaust emissions controls, projects that allow for complete and timely withdrawal of gas from the storage fields and allow the engines to meet new Michigan NOx Reasonably Available Control Technology ("RACT") Rules emission requirements.

Q. Please identify the capital expenditures projected for the Ray Compression Station.

A. Exhibit A-12 (TKJ-5), Schedule B-5.7, page 2, line 6, identifies the total capital expenditures for the Ray facility. In 2022, the Company incurred costs for valve replacements. In 2023 through 2025, examples of projected costs include: valve replacements, air compressor system upgrades, and piping support restoration. These projects will ensure the complete and timely withdrawal of gas from the storage fields.

Q. Please identify the capital expenditures projected for the St. Clair Compression Station.

A. Exhibit A-12 (TKJ-5), Schedule B-5.7, page 2, line 7, identifies the total capital expenditures for the St. Clair Compression Station. In 2022, the Company incurred costs for engine controller replacement and suction filter separator installation. In 2023 through 2025, examples of projected costs include turbine gas cooler replacement, dehydration system superheater replacement and gas blowdown vent stack replacement. These projects will ensure the complete and timely withdrawal of gas from the storage fields and safe gas blowdown when required.

Q. Please identity the capital expenditures projected for White Pigeon.

A. Exhibit A-12 (TKJ-5), Schedule B-5.7, page 2, line 8, identifies the total capital expenditures for White Pigeon. In 2022, the Company incurred costs for lube oil extractor installation. In 2023 through 2025, examples of projected costs include air compressor replacements and a solar battery installation that is a green project that will reduce cost of electricity for the site.

Q. Please identify the capital expenditures projected for the Marion Storage Fields.

A. Exhibit A-12 (TKJ-5), Schedule B-5.7, page 2, line 9, identifies the total capital expenditures for the Marion Storage Fields. In 2022, the Company incurred costs for well rehabilitation, storage lateral replacement, new well installation and the Riverside field retirement project. In 2023 through 2025, the projected costs include an upgrade to the Marion storage operations building.

Q. Please provide more detail about the Riverside storage field retirement project.

A. The Riverside storage field has low working gas capacity, the largest well count compared to other Company gas storage fields with similar working gas volumes, and native hydrogen sulfide, which is flammable and lethal at high concentrations, that has caused it to be identified as high-risk within gas storage. The Riverside gas storage field is connected directly to three city gates which limits the withdrawal volume from the field and the ability to take outages for maintenance or capital projects and the ability to increase capacity at McBain city gate. The integrity of the mainline and laterals that support the field are degrading, in some cases causing pressure derates. For these reasons, the Company has decided to end operation of the entire storage field.

Q. What type of engineering analysis and alternative analysis was performed to develop the Riverside retirement plan?

A. The engineering and gas supply team performed several models that included full field retirement, plugging and abandoning portions of the field, and optimizing the field with new horizontal wells. The evaluation also included determining gas withdrawal from the gas storage field. During the original analysis low gas price projections, along with the equipment necessary and timing of withdrawal, Consumers Energy determined that it would not be economical for the Company to spend capital to withdraw gas from the Riverside field. The Company modeled and evaluated several alternatives until a solution was determined. The selected solution will mitigate the current storage and transmission risk associated with the field, improve resiliency and reliability to customers connected to McBain, Forward, and Falmouth city gates (customers that are currently being supplied through the storage field), continue to provide affordable gas in the Riverside area, and reduce methane emissions with the plugging of the storage wells.

When gas prices increased in 2022, the Company revisited options for the withdrawal of gas from the field, including the option of selling the field to a third party. At this time, the analysis and decision are on-going and are projected to conclude by the end of 2023. The work to remove customers from being fed by the storage field will continue as it is required for any of the possible retirement/divestment options. Buyers would likely extract all working and base gas, as much as possible.

Q. What is the estimated timeline and projected cost for the Riverside retirement project through the year 2026?

A. A breakdown of the projected spending for the Riverside retirement project is included in Exhibit A-12 (TKJ-5), Schedule B-5.7, page 2, line 18, the projected project spending does not include Cost of Removal. Distribution and Transmission asset modifications to disconnect customers from the storage field and re-supply from the system are planned for 2024 and 2025. Final abandonment of the field to occur tentatively before the end of 2026.

Q. Has the Company's Board of Directors approved the Riverside retirement project?

A. No. The Riverside retirement project had originally planned to be presented to the Board of Directors Finance Committee for approval in October 2022. However, the project cost no longer meets the Board of Directors' updated threshold for Finance Committee approval. Therefore, approval from the Board of Directors is not necessary to move forward with this project.

Q. Please identify the capital expenditures projected for the Northville Storage Fields.

A. Exhibit A-12 (TKJ-5), Schedule B-5.7, page 2, line 10, identifies the total capital expenditures for the Northville Storage Fields. In 2022, the Company incurred costs for its project to install a liquid handling system at the Lyon 29/34 storage fields. In 2023 through 2025, the projected costs include additional investment to complete the liquid handling system at the Lyon 29/34 storage fields.

Q. Please describe the Lyon 29/34 project.

A. The Lyon 29/34 storage gas gathering and metering site has been in operation for more than 22 years. The facility feeds gas to transmission Line 1020 and to the Northville compressor station. The primary focus of the Lyon 29/34 facility is to deliver transmission quality gas to the pipeline system and act as a metering station. On peak days, this site is an important additional source of natural gas supply to the metro Detroit area. During 2018, 2019, and 2020 there were multiple occasions of gas purity issues occurring during the gas withdrawal season. During gas withdrawal, the gas water content exceeded the regulatory threshold of 7 LB/MMCF, which affected the storage field, and required pre-mature shut-in of withdrawal operations. The Lyon 29/34 facility upgrade project will help improve gas purity, measurement accuracy, and pipeline reliability by reducing corrosive components from the gas stream and improve site performance by installing gas purification equipment. In 2022, the expenditures were for project engineering and design. The 2023 expenditures are for concluding engineering, design and securing long lead time materials. The 2024 and 2025 expenditures are for securing remaining materials and performing construction, start up and project close out for the project. This project will help address the Company's objective of a reliable system, which will reduce unplanned outages during normal site operations.

Q. Was gas blending considered as an alternative to this project?

A. Yes. The Company does not consider blending a competent means of ensuring gas quality. Various conditions can affect how and whether gases are mixed in a pipe. Due to the integrated nature of Consumer Energy's gas system, its variable operating conditions, and the fact that the system is not designed to assure mixing of gas from different sources, it would be inaccurate to assume mixing occurs.

Q. Please identify the capital expenditures that are planned for the Overisel Storage Fields.

A. Exhibit A-12 (TKJ-5), Schedule B-5.7, page 2, line 11, identifies the total capital expenditures for the Overisel Storage Fields. In 2022, the Company incurred costs for disposal well tank replacement, wellhead protection and well rehabilitation. In 2023 through 2025, projected costs include well rehabilitation and scrubber brine tank replacement.

Q. Please identify the capital expenditures projected for the Ray Storage Fields.

A. Exhibit A-12 (TKJ-5), Schedule B-5.7, page 2, line 12, identifies the total capital expenditures for the Ray Storage Fields. In 2022 through 2025, the projected costs includes valve replacements and a launcher receiver replacement.

Q. Please identify the capital expenditures projected for the St. Clair Storage Fields.

A. Exhibit A-12 (TKJ-5), Schedule B-5.7, page 2, line 13, identifies the total capital expenditures for the St. Clair Storage Fields. In 2022, the Company incurred costs for a field liquid separator installation, a new storage well and storage well data acquisition. In

2023 through 2025, examples of projected costs include completion of a field liquid separator installation and a disposal well facility upgrade.

Q. Please identify the capital expenditures that are planned for Storage New Wells.

A. Exhibit A-12 (TKJ-5), Schedule B-5.7, page 2, line 14, identifies the total capital projected expenditures to complete the Company's new storage well drilling plan. In 2022, the Company incurred costs for drilling a new well in the Lenox field, drilling the vertical portion of two wells in the Cranberry field, also engineering and preparation for future well drilling and close out/flow testing after drilling. Flow testing of the new Lenox well in 2023 has shown expected flowrates when operating with the other wells within the field and the ability to flow higher rates if nearby wells are unavailable. In 2023 through 2025, the projected capital expenditures include funding for the engineering, site preparation, and drilling of new wells including the completion of two wells in the Cranberry field. The table below outlines the timing and location of the Company's plan for drilling new wells.

Table 7: Proposed New Well Drilling Plan

Drill Year	Location	Field	New Well ID	Projected Cost
2023	Marion	Winterfield	W-994	$3,338,861
	Marion	Cranberry	C-995	$6,300,178
	Marion	Cranberry	C-996	$5,251,591
2024	Overisel	Overisel	O-305	$9,759,300
	Marion	Cranberry	C-994	$6,563,713
2025	Marion	Winterfield	W-1004	$10,253,314
	Marion	Winterfield	W-1005	$7,728,750
	Marion	Winterfield	W-1006	$7,728,750
	Marion	Cranberry	C-1103	$10,641,316

Q. Please provide a description of the project at W-994 in the Winterfield Storage Field.

A. The project is a well re-entry focused on re-entering existing horizontal or deviated wells and drilling new horizontal drainhole sections. Re-entering an existing well further helps to improve field and well deliverability, especially for wells that were drilled off structure or too deep on the structure. The re-entry work is also expected to be significantly less expensive than a full new well as the casing, wellhead equipment and pipeline are already installed. There are multiple wells in Winterfield, Lyon 34, and Four Corners that are potential future candidates pending the results of the W-994 project.

Q. Please identify the capital expenditures that are planned for Well Rehabilitation.

A. Exhibit A-12 (TKJ-5), Schedule B-5.7, page 2, line 15, identifies the total capital projected expenditures for the Storage Well Rehabilitation Capital Program. Exhibit A-84 (TKJ-6), Storage Well Rehabilitation Capital Program Detail, provides additional detail for this multi-year program that is in response to the federal minimum safety standards that are described previously in my testimony.

Project spending for 2023 through the end for the program was determined using estimates created based on work scopes developed by Storage Engineering. The work scopes are broken down into activities and costs and are developed using the projected duration of the activity using a vendor rate or on a cost-per-well basis, again based on a vendor quote. A description of the different work scopes and associated costs is shown on the Scope Averages tab of Exhibit A-84 (TKJ-6). The scope specific estimates were added together with the wells of similar scope types and averaged. This average was used to build the annual project expenses based on the number of each well scope performed each year. These costs are displayed on the Annual Estimate tabs of Exhibit A-84 (TKJ-6).

Q. Please provide more detail on the Well R ehabilitation Program.

A. The primary goal of the Well Rehabilitation Program is to identify and reduce well risk by ensuring the integrity of the wells across the Company's gas storage system, preventing a large-scale methane emission event like Aliso Canyon. The secondary goal is to enhance well deliverability while working on the well. This program will initially provide a baseline of well integrity conditions, which will be incorporated into the ongoing development of the Storage Integrity Management Plan ("SIMP"). Development of the SIMP is ongoing and the associated Risk Assessment Model is being used to identify well prioritization for the program. The completion of the logging portion will help complete a portion of the baseline assessment required from the PHSMA final rule.

This program will use mechanical methods, solvents, and other chemicals to remove obstructions, restoring the original flow properties of the wells. This thorough Well Rehabilitation Program will remove the debris and slow the rate of corrosion potential in the wells, thus increasing the useful life of the facilities.

Depending on the condition of the well, additional replacement of well components may be necessary. Components include, but are not limited to, piping, valves, or packers. To verify success of the Well Rehabilitation Program, flow statistics are taken both before and after the rehabilitation on select wells. Absolute Open Flow ("AOF") values are measured and compared to historical AOFs taken on the wells when originally put into service. Wells will be "logged" or inspected before treatment to assess the condition of the well casing and the success of the restoration. The program will bring the Company up to a seven-year reassessment cycle, into compliance with the API RP 1171, as part of the Storage system objectives as outlined in the NGDP.

Completing the rehabilitation and well logging work simultaneously is prudent, efficient, and directly benefits our customers and public safety. If done separately, services such as well service rigs, well hardware, and other ancillary services would be duplicated, which is not cost effective for the customer. This program is designed to restore, and in most cases, increase well deliverability while baselining well integrity to an industry average of approximately 10 years. Once baseline well integrity information is determined, a risk-based, site specific approach to future well integrity well logging will be implemented as detailed in the API RP 1171: Functional Integrity of Natural Gas Storage in Depleted Hydrocarbon Reservoirs and Aquifer Reservoirs. At the completion of the well rehabilitation capital project, well logging O&M will be required to maintain the approximately seven-year cycle.

Q. Why is the Well Rehabilitation Program a capital program?

A. Federal Energy Regulatory Commission ("FERC") Docket Nos. AC09-27-000 and AI05-1-000 illustrate FERC's allowance of testing costs incurred to extend the useful life of the system in the context of a one-time rehabilitation program to be capitalized. Under the requirement of FERC's Uniform System of Accounts, costs incurred to inspect, test, and report on the condition of an existing plant to determine the need for repairs or replacements, and testing the adequacy of repairs made, are recognized as maintenance expense. However, FERC has permitted natural gas and electric companies to capitalize assessment costs when the work was done in connection with major rehabilitation projects involving significant replacements and modifications of facilities.

FERC has established the following requirements that a project must meet to be able to capitalize assessment type costs. The project must: (i) be completed in connection with a one-time program that involves significant replacements and modifications of facilities; (ii) extend the overall system's useful life and serviceability; and (iii) have in place internal controls to distinguish between costs incurred related to ongoing assessment activities and those that are part of the rehabilitation project. The Well Rehabilitation Program meets these requirements.

Q. Please identify the capital expenditures that are planned for Storage Pipeline Replacement.

A. Exhibit A-12 (TKJ-5), Schedule B-5.7, page 2, line 16, identifies the total 2023 through 2025 capital projected expenditures for storage pipeline replacements. The projected pipeline replacement schedule is shown in Table 8, it includes the total projected cost of each project including both pipeline replacement and retirements. Retirement projects are provided for information only, they are entirely Cost of Removal/Retirement ("COR") expense and are not part of the request in this proceeding.

Q. Please provide more detail on the Storage Pipeline Replacement Program.

A. The Storage Pipeline Replacement Program is a program that performs replacement and retirement of storage pipelines to reduce the probability of major failure. All storage pipelines replacements and retirements will be tracked under the Transmission Integrity Management Program ("TIMP"), following 49 CFR 192 Subpart O, for risks and consequences of failures. Projects have been prioritized based on factors such as risk, future new well drilling, and planned well plugging. Replacement and retirement of these storage pipelines contribute to safety of our company employees and the public, deliverability, resilience, and integrity of our system.

Table 8: Projected Pipeline Replacement Schedule

Year	Location	Project Name	Project Type*	Projected Cost	Length (ft)
2023	Marion	Cranberry Lateral 67E-Launcher/Receiver	Replacement	$815,072	53
2023	St. Clair	Puttygut Mainline	Replacement	$3,649,000	1,426
2024	Overisel	Overisel Lateral 2	Replacement	$8,899,720	5,095
2024	Marion	Cranberry Lateral 61W	Replacement	$4,620,000	1,785
2025	Overisel	Overisel Lateral 3	Replacement	$8,281,000	5,227
2025	Marion	Winterfield Lateral 52SB	Replacement	$4,446,000	1,056
2025	St. Clair	Hessen Full field	Replacement	$14,708,988	33,898
2023	Marion	Cranberry Lateral 62W	Retirement	$1,645,798	9,768
2024	Overisel	Overisel ML - 10", ML – 12”, Lateral 9, 8, 7E/W	Retirement	$5,594,252	42,451
2024	Marion	Cranberry Lateral 63W	Retirement	$420,000	1,486
2025	Overisel	Salem North Lobe Retirement	Retirement	$4,142,000	16,685
2025	Marion	Winterfield Lateral 56N	Retirement	$1,384,000	5,069
2025	Marion	Winterfield ML 22”	Retirement	$1,366,000	6,706

* Retirement projects are provided for information only, they are entirely COR expense and are not part of the request in this proceeding.

In previous years, the Company’s Enhanced Infrastructure Replacement Program (“EIRP”) has provided funding for the storage field lateral and mainline replacements, specifically for known higher-risk pipe within the storage fields. This includes pre-1970 Low Frequency Electric Resistance Welded (“LFERW”) pipe. This pipe has been deemed higher relative risk pipe industry wide.

Starting in 2018, the Company ended the Transmission EIRP program and began this program to address the storage pipelines that do not qualify for EIRP funding. The well lines in the Overisel, Salem, Winterfield, Cranberry, and Riverside fields are original piping from initial field construction (Late 1940’s and Early 1950’s). Leaks have periodically developed on the well lines – average two-five per year across all of the fields. The condition of the well lines cannot be assessed with Inline Inspection tools since they are not piggable.

Q. Please identify the capital expenditures that are planned for Well Data Acquisition.

A. Exhibit A-12 (TKJ-5), Schedule B-5.7, page 2, line 17, identifies the total capital projected expenditures for well data acquisition. In 2022, the Company incurred costs for well data acquisition equipment installation at the Ray Storage Field. In 2023 through 2025, project costs include funding for engineering, procurement, and installation of well data acquisition equipment on 24 wells in the Puttygut storage field.

Q. Please provide more detail on the Well Data Acquisition.

A. PHMSA's adoption of API RP 1171 recommends increased monitoring of gas storage wells. In order to monitor flow, temperature, pressure, and other variables in real time, Remote Terminal Units and Supervisory Control and Data Acquisition systems need to be installed and equipped with sensing equipment at the well head. Along with complying with federal regulations, the ability to monitor issues on a well-by-well basis in real time during injection and withdrawal will provide valuable data to storage engineers that can be used to optimize the injection cycle and ensure deliverability from the field.

In 2020, the Company performed work on approximately 12 Ray wells. The work on the remaining Ray wells was completed in 2022 and closed out in 2023. In 2024 engineering and procurement will begin for a 2025 installation on 24 wells in the Puttygut storage field. The program plans to implement the technology in the peaker and intermediate fields, along with top performing and/or horizontal wells in the baseload fields.

Q. Please identify the capital expenditures that are planned for Safety Valve Installation.

A. Exhibit A-12 (TKJ-5), Schedule B-5.7, page 2, line 19, identifies the total capital projected expenditures for safety valve installation. Funding for safety valve installation projects begins in 2024.

Q. Please provide more detail on the Safety Valve Installation.

A. A SIMP integrity assessment (based on the regulatory requirements of API RP 1171 as referenced in 49 CFR 192.12) of surface equipment identified the need to standardize safety equipment on certain wells within higher deliverability fields. Protecting against a gas excursion from the individual well bore during any potential safety incidents. The projected work scope installs 32 safety valves at various well sites within the St. Clair fields.

<u>Freedom Upgrade Project</u>

Q. Please describe Exhibit A-12 (TKJ-5), Schedule B-5.7, page 2, line 1.

A. Exhibit A-12 (TKJ-5), Schedule B-5.7, page 2, line 1, identifies the total capital expenditures for the Freedom upgrade project.

Q. What level of capital spending does the Company propose for the Commission to incorporate into rates in this case for the upgrade project to Freedom?

A. The Company's request for rate relief in this case reflects capital spending on the upgrade project to Freedom in the amount of $13.6 million for 2022 (Actual); as provided in Exhibit A-12 (TKJ-5), Schedule B-5.7, page 2, column (b), line 1; $7.6 million for 2023 (Projected), as provided in Exhibit A-12 (TKJ-5), Schedule B-5.7, page 2, column (c), line 1; $0.4 million for the nine months ending on September 30, 2024 (Projected), as provided in Exhibit A-12 (TKJ-5), Schedule B-5.7, page 2, column (d), line 1; $8.0 million for the 21 months ending on September 30, 2024 (Projected), as provided in Exhibit A-12 (TKJ-5), Schedule B-5.7, page 2, column (e), line 1; and $0.0 million for the test year ending September 30, 2025 (Projected), as provided in Exhibit A-12 (TKJ-5), Schedule B-5.7, page 2, column (f), line 1.

Q. Please summarize the capital expenditures included in Exhibit A-12 (TKJ-5), Schedule B-5.7, included in this direct testimony for the Freedom upgrade project.

A. Exhibit A-12 (TKJ-5), Schedule B-5.7, page 2, line 1, identifies the total capital expenditures for the Freedom upgrade project. Phase 1 of the Freedom upgrade project and engineering for Phase 2 were both completed in 2017. In 2018 through 2023, and the 12 months ending September 30, 2024, the Company incurred and will continue to incur costs for completion of construction of a new compressor and auxiliary buildings, relocation of the two temporary compressors to their final locations, commissioning of the new equipment and project close out.

Q. What is the annual investment for the overall Freedom upgrade project?

A. The annual investment for the Freedom upgrade project for the completed work and the work that is currently planned is shown in the table below. The projected amounts will continue to be evaluated as the project progresses and moves toward completion.

Anticipated Spend (Millions)	
2016	$16.8 (actual)
2017	$30.2 (actual)
2018	$62.3(actual)
2019	$83.0 (actual)
2020	$19.7 (actual)
2021	$13.8 (actual)
2022	$13.6 (actual)
2023	$7.6 (projected)
2024	$0.4 (projected)
Total	$247.4 (projected)

Q. Please provide further details regarding the phases of the Freedom upgrade project.

A. The Freedom upgrade project is being completed in two phases, followed by some work for site restoration and closing out the project. Phase 1, now complete, included costs for engineering, procurement of two new compressor engines (that were installed on engine skids and placed in temporary locations to improve plant reliability until the final installation is complete), and the start of construction for a new compressor building.

Phase 2 of the Freedom upgrade project, which is also now complete, includes costs for continued engineering, procurement of three additional compressor engines, completion of the new facility, and demolition of the old compressor building. Now that Phase 2 is complete, all five new compressor engines (18,750 BHP) are permanently installed in the new compressor building and the existing compressor buildings have been demolished.

Q. What is the timeline of the Freedom upgrade project?

A. Major milestones for the Freedom upgrade project are shown in the table below.

Milestone	Anticipated Completion Date	Status
Phase 1 compressors complete (first two new compressors installed in temporary location)	December 2017	Complete
Phase 2 air permit received	December 2017	Complete
Phase 2 engineering complete	December 2017	Complete
Phase 2 board approval	May 2018	Complete
Phase 2 construction start	July 2018	Complete
Phase 2 first three compressors complete	October 2020	Complete
Phase 2 move Phase 1 compressors to permanent location	November 2022	Complete
Demolition of Plant 1 and 2, site restoration, and documentation completion (close-out)	May 2024	On schedule

Q. What is the operating state of Freedom now that Phase 2 (move Phase 1 compressors to permanent location) is complete?

A. With the completion of Phase 2 (move Phase 1 compressors to permanent location), Freedom has all five new compressor engines (18,750 BHP) permanently installed and commissioned in the new compressor building. Retirement and demolition of existing compressors and buildings has been completed. Site Restoration and Project close out is projected to be completed in May 2024.

Q. Please explain the primary considerations that caused reliability concerns prior to the start of the Freedom upgrade project?

A. The primary considerations included:

(i) The age and condition of the legacy equipment at the station. For example, all components of the existing station (engines/compressors, critical systems, gas conditioning, and support infrastructure) were determined to be in fair to poor health. More specifically, the compressor building, engine, and scrubber foundations showed signs of cracking and deterioration. The condition of the Unit 57 foundation led to placing that unit in mothball status. Station valves had obsolete valve operators. Engine control panels, gaskets, and seals are old and replacement parts were difficult to source. The largest engine

(TLA-1), Units 13 and 60 suffered a significant failure and were no longer available for service. Oil and glycol tanks were underground, and Plant 1 relied on water from Pleasant Lake for engine cooling, which was not an optimal configuration for such equipment.

(ii) High actual ROR as shown in the table below.

Year	Average ROR
2012	15.7%
2013	12.5%
2014	22.8%
2015	11.0%
2016	3.0%
2017	5.8%
2018	35.2%
2019	21.8%
2020	21.7%
2021	31.3%
2022	9.9%*
2023 YTD Sept	7.1%**

*Improvement in ROR due to the use of first three new units.

**2023 ROR includes all five new units in the permanent locations.

(iii) Increasing supply demands at Freedom. These considerations caused uncertainty related to the Company's ability to consistently meet design supply requirements at the second largest supply location on the system.

Based on an assessment conducted in 2015, the Company forecasted about a 75% probability of consistently meeting design day requirements over the next five years with the original existing engines, compared to a target of 95%. Further decreases in overall reliability would have reduced this probability to a level lower than 75%. Phase 1 provided back-up horsepower to offset such an occurrence. It also provided capacity to support an increase in supply requirements at Freedom, which is discussed later in this direct testimony. This phased approach helped to meet supply requirements until the completion of Phase 2. Further, the increased reliability of Freedom is enabling the Company to meet its primary public service obligation to maintain gas service to its customers.

Q. Please quantify the increase in supply demand at Freedom.

A. Annual throughput has more than doubled from about 42 Bcf in 2005 to about 88 Bcf in 2019. The percentage of Freedom's portion of the supply to the total system supply has also doubled from about 12% to about 27% of total system supply due to favorable pricing caused by the shale gas supplied through the Freedom location. In addition, Freedom has experienced an increasing trend in the maximum daily flowrate over that same timeframe. These supply increases also contributed to the decision to complete the upgrade project with a multi-phased approach.

Q. Why is this work necessary?

A. Freedom is the oldest station on the system. When the upgrade project began, Freedom operated nine compressor units—seven of these units were installed in 1948. These units and the remaining station equipment were at the end of their useful operating life and failed to meet the required reliability standards for the reasons discussed above. Although the units failed to meet current required reliability standards, it should be noted that the existing compressor engines in Plants 1 and 2 were installed prior to August 15, 1967. As a result, they are considered "grandfathered" and were not subject to New Source Review permitting requirements at the time of installation. In addition, each of these engines are classified as "existing" spark-ignition stationary reciprocating internal compressor engines >500 HP located at a major source of hazardous air pollutants. Therefore, pursuant to §63.6590(b)(3)(i), they do not have to meet the requirements of 40 CFR Part 63 Subparts A and ZZZZ.

Q. What alternatives to this project were considered?

A. Seven station configuration options were evaluated. The options included various configurations of re-building existing and installing new large and small units. The selected configuration outlined in this direct testimony had the most favorable financial results while delivering the required reliability improvements and capacity increases. Option one consisted of re-building existing units and renting interim compression to bridge the gap to installing two new 3,750 HP units. Option two consisted of re-building the existing units and renting interim compression to bridge the gap to installing three new large units. Option three consisted of installing four new large units and one small unit. Option four consisted of installing five new large units and one small unit. Option five consisted of building five new large units. Option six consisted of installing 13 smaller new units. Option seven, the selected option, consisted of installing five new large units, two of which were installed early in a temporary location.

Q. What is the priority of the Freedom upgrade project compared to other projects?

A. Freedom is the second largest gas supply location within Consumers Energy's system. If the Company experienced a major unplanned event at Freedom that eliminated the ability to pump, then Freedom could not reliably accept supply at that point, which could negatively affect some customers' supply. The capacity without pumping, if even possible, might range from 0 to 50 MMcf/d depending on the available pressure at the inlet of the station. The total pipeline supply throughput at Freedom in 2016 was 78 Bcf, or 24% of the total pipeline system supply. Of the 78 Bcf, the vast majority, or 51 Bcf, occurred during the summer period, in part to support storage injection operations. Maintaining summer supply capacity to support summer injection operations is critical to realizing the winter gas pricing benefit provided by the storage fields and to supplying customers during the winter. To give some perspective, storage field supply provides about 80% of the total system supply requirements on very cold winter days. For this reason, refilling storage in the summer is a primary operating objective and Freedom plays a significant role in meeting this objective. The summer-winter market natural gas price differential has averaged approximately $0.57/MMbtu in the five-year period (2017-2022).

Q. Will the Freedom upgrade project improve reliability?

A. Yes. The Freedom upgrade project replaced the existing old compressors, the new compressors will move station horsepower from 10,400 BHP to 18,750 BHP which will increase station pumping capacity. The upgrade project will also improve reliability by providing new valves, gas conditioning, separators, and emergency generators. The legacy compression reliability was no longer sufficient to meet customer short- and long-term demands. This improved reliability is critical to ensuring this station can meet system demand for summer injection and winter delivery, thereby providing the winter pricing benefit of the storage fields to our customers. Phases 1 and 2 improve the probability of consistently meeting design requirements from 75% to over 95%.

Q. Will the project provide additional station capacity beyond its current ability?

A. Yes, the new facilities will provide about 65 MMcf/d of additional design capacity under many, if not most, operational conditions. The station may be capable of higher flows if operational conditions are more favorable than the design accounts for. This additional capacity will allow for the take-away of additional gas from the upstream interstate pipelines so that abundant gas supply from northeast shale production sources can be leveraged to benefit the Company's customers. The increased capacity provides additional access to potentially favorable market pricing at that location. These potential savings would be realized by customers. Based on Consumers Energy's supply portfolio for GCR customers, the delivered cost of the Freedom pathway at an undiscounted tariff rate is about \$0.10/dth to \$0.65/dth lower than other existing and future supply pathways. Consumers Energy has leveraged this favorable pricing by contracting for interstate capacity to deliver to Freedom through 2023.

Q. Will the Freedom upgrade project reduce emissions?

A. Yes. Freedom's over 60-year-old compressor units have been replaced with new units that are more environmentally friendly and more efficient.

Q. Has the Company's Board of Directors approved the Freedom upgrade project?

A. The Company's Board of Directors approved Phase 2 in May 2018.

Q. Are the Company's capital expenditures in GCS reasonable?

A. Yes. The capital expenditures in GCS will improve system reliability, deliverability, integrity, safety, and customer service. These capital expenditures will allow the Company to take advantage of market conditions and procure adequate supplies of natural gas to meet the needs of our customers. Furthermore, many of these capital expenditures are related to compliance with environmental, federal, and/or state regulations, and thus not discretionary.

(v) <u>IT PROJECTS</u>

Q. Is the Company planning technology projects that support the engineering, asset planning, design, construction, and maintenance of a safe, reliable, and affordable distribution, transmission, compression and storage systems for its customers?

A. Yes. Company witness Stacy H. Baker includes in her direct testimony and exhibits, technology projects that are critically important to supporting these gas functions within the Company. The expenditures for these projects are contained within her exhibits. The projects which will provide benefits for the area which I am sponsoring are described below:

- The **Gas Compression Digital Work Management** project requires $230,783 in capital and $16,050 in O&M in the test year. The project provides work management software and digital forms for Gas Compression facilities. The current work management process for Gas Compression is cumbersome, largely paper based, and is made up of multiple disconnected systems. This leads to poor visibility, process inefficiency and waste, re-work, regulatory risk, and human error. This project provides value to the Company through: (1) increased productivity by direct data entry in the field; (2) improved quality through increased accuracy of updates completed at the time and place of the work; (3) elimination of the need to enter data into multiple disconnected systems, and (4) improved safety through access to real-time information used at work sites rather than printed procedures. The scope of the project includes: (1) Merging the existing work management tools into a single work management solution, (2) purchasing licenses to add Gas Compression users to the company's existing mobile work management software, and (3) configuring changes in SAP and the mobile work management software to replace the paper-dependent work management process with the ability to access and update maintenance, operations, and safety information for Gas Compression. Alternatives considered include: (1) Utilize an SAP work management mobile solution. An SAP work management solution is not preferred since it is a new solution and requires additional project and support cost. (2) Continue the manual paper-based process. Continuing the manual paper-based process was not chosen because of process waste, re-work, and human error. (3) Customize the existing electronic Shift Operations Management System (eSOMS) mobile application to add work management functions. A custom eSOMS mobile application was not chosen because it would require additional project cost and an ongoing support budget for a custom solution that the eSOMS product was not intended to support. (4) Adopt a cloud based SAAS solution. This option was not selected as it was a high-cost option. (5) Utilize the existing Service Suite solution currently deployed for similar work processes in Gas Transmission. Service Suite is in other Gas and Electric departments. The Service Suite solution is the preferred option because it is a proven solution at the Company and provides the mobility and digital benefits at a lower cost.

- The Gas Compression Probabilistic Risk Model project requires $1,182,263 in capital and $121,875 in O&M in the test year. The Gas Compression Probabilistic Risk Model project will implement a risk analysis model for comprehensive predictive risk analysis and modeling on gas compression assets. The current Gas Compression model is a relative risk model that equates risk to dollars from input information using qualitative data and ordinal scales to produce a "risk ranking". In simple terms, the relative risk model is not capable of creating a statistically significant result. The risk assessment used in the current model provides a ranking for likelihood, consequence, and risk that is relevant only in comparison to other rankings. While the outputs provide a sense of relative risk when comparing one facility to another, the ranks do not provide anything qualitative that relates to the failure of compressor stations. 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 gas compression system improvement projects. Implementing probabilistic risk modelling supports the changes planned for in the Company's Natural Gas Delivery Plan (NGDP), including the Company Gas Management Safety 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, and (2) configure multiple data sources, to make advanced statistical calculations for interacting threats, both of which allow the Company to make more informed financial and strategic decisions based on improved quality inputs and mitigate the risk of outages at the compression stations.. The probabilistic model will rank the compression stations in risk-associated dollars making it easier to interpret risk results for the purpose of making business decisions. Furthermore, the Pipeline and Hazardous Materials Safety Administration (PHMSA) has identified the probabilistic risk model as a potential best practice for transmission operators over other risk, so the project adds value by aligning with industry best practices. The project scope encompasses the implementation of a probabilistic risk model for gas compressor stations. The project will: (1) install and configure risk model; (2) configure multiple data sources; and (3) develop reports and dashboards. Alternatives considered include: (1) continue the use of the relative risk model, but invest in substantial effort to continually manually managing data inputs and quality checks (2) implement a custom, Excel-based probabilistic risk model through a consulting effort; (3) implement an on-premise probabilistic risk model, and (4) implement a cloud-based model. The first alternative was not selected because although the manual effort is possible, it is becoming increasingly difficult to complete as the model utilizes more data sources that need to be annually updated and validated. The second 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". The on-premise solutions analyzed are not mature and have not been widely tested with transmission operators, so alternative three was not selected. The fourth alternative of implementing the cloud-based probabilistic risk model was chosen because it is the most cost-effective long-term implementation approach, providing commercial, off-the-shelf capabilities, industry-proven technology, and an ongoing vendor support and upgraded model.

- The **Gas Storage Probabilistic Risk Model** project requires $129,225 in capital and $40,088 in O&M in the test year. The Gas Storage Probabilistic Risk Model project will implement a risk analysis model for comprehensive predictive risk analysis and modeling on gas storage wells. The current Gas Storage model is a relative risk model that equates risk to dollars from input information using qualitative data and ordinal scales to produce a "risk ranking". In simple terms, the relative risk model is not capable of creating a statistically significant result. The risk assessment used in the current model provides a ranking for likelihood, consequence, and risk that is relevant only in comparison to other rankings. While the outputs provide a sense of relative risk when comparing one well to another, the ranks do not provide anything qualitative that relates to the failure of wells. Also, the current transmission model does not meet the requirements of the MPSC, as indicated in a letter of noncompliance (dated January 15, 2019), and rule-making for storage systems has historically followed transmission rule-making. Lastly, the current model introduces risk in PHMSA findings as a non-probabilistic model. 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 well improvement projects and improved targeted plug and abandonment projects. Implementing probabilistic risk modelling supports the changes planned for in the Company's Natural Gas Delivery Plan (NGDP), including the Company Gas Management Safety 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, and (2) configure multiple data sources, to make advanced statistical calculations for interacting threats, both of which allow the Company to make more informed financial and strategic decisions based on improved quality inputs and mitigate the risk of PHMSA findings. The probabilistic model will rank the wells in risk-associated dollars making it easier to interpret risk results for the purpose of making business decisions. Furthermore, the Pipeline and Hazardous Materials Safety Administration (PHMSA) has identified the probabilistic risk model as a potential best practice for storage operators over other risk models (PHMSA Pipeline Risk Modeling white paper, dated May 9, 2018), so the project adds value by aligning with industry best practices. The project scope encompasses the implementation of a probabilistic risk model for gas storage wells. The project will: (1) install and configure risk model; (2) configure multiple data sources; and (3) develop reports and dashboards. Alternatives considered include: (1) continue the use of the relative risk model, but invest in substantial effort to continually manually managing data inputs and quality checks; (2) implement a custom, Excel-based probabilistic risk model through a consulting effort; (3) implement an on-premise probabilistic risk model; and (4) implement a cloud-based model. The first alternative was not selected because although the manual effort is possible, it is becoming increasingly difficult to complete as the model utilizes more data sources that need to be annually updated and validated. The second 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". The on-premise solutions analyzed are not mature and have not been widely tested with transmission operators, so alternative three was not selected. The fourth alternative of implementing the cloud-based probabilistic risk model was chosen because it is the most cost-effective long-term implementation approach, providing commercial, off-the-shelf capabilities, industry-proven technology, and an ongoing vendor support and upgraded model.

- The **Gas Compression Historian** project requires $1,661,063 in capital and $133,207 in O&M in the test year. This project will extend the gas historian strategy to standardize historian usage and analytics for compression plants to allow for more timely and accessible operational analytics that will enable better asset management, troubleshooting, and support. Historian usage is inconsistent across the gas compression fleet. Each gas compression location has a unique historian capability and/or vendor platform, and many historian instances do not meet the retention capabilities required nor are many using the standard Company platform. As a result of the inconsistent historian instances, the Company is unable to generate enterprise level analytics to holistically view the compression fleet. This project will add value to the Company through: (1) reducing unplanned outage rate through better visibility into operational data and operational base-lining; (2) improving transparency into demand delivery through modeling requested rate versus available rate; (3) improving predictability for preventive maintenance; and (4) standardizing historian usage and analytics to enable more timely and accessible operational analytics that will allow for better asset management, troubleshooting, and support. The scope of this project includes: (1) implementation of the Company standard historian platform for gas compression; and (2) data integrations with Freedom, Muskegon, Northville, Overisel, Ray, St. Clair, and White Pigeon compressor stations. Alternatives considered include: (1) augmenting existing gas management services staff to manually perform data collection and analysis. This alternative was not selected because it would require a significant increase in resources to perform the work to gather data from each compressor station and perform analysis and reporting using existing desktop tools. Additionally, this alternative would not support the data required for setting system alarms, and data would not be current. (2) Deferring implementation to 2024. This alternative was not selected because it continues to defer value realization and does not provide a timely response to add this capability to support the Natural Gas Delivery Plan. (3) Implement gas compression historian using the Company standard platform. The third alternative was selected because it leverages and extends the existing investment in resources and capabilities.

Q. Does this complete your direct testimony?

A. Yes.

S T A T E O F M I C H I G A N

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter 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-21490

DIRECT TESTIMONY

OF

ERIC J. KEATON

ON BEHALF OF

CONSUMERS ENERGY COMPANY

December 2023

Q. Please state your name and business address.

A. My name is Eric J. Keaton, and my business address is One Energy Plaza, Jackson, Michigan 49201.

Q. By whom are you employed?

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

Q. What is your position with Consumers Energy?

A. I am a Manager of Sales & Revenue Forecasting in the Financial Planning & Analysis Department.

Q. Please state your educational background.

A. I graduated from Auburn University at Montgomery, Alabama, in November 1999, with a Bachelor of Science in Business Administration degree. In addition, I have attended a number of courses on utility ratemaking, load research, and forecasting.

Q. What is your regulatory experience?

A. Prior to joining the Company, from January 1996 through February 2004, I worked in a variety of positions in technical support, systems analysis and design, database management, programming, and business analysis. I joined Consumers Energy in March 2004 as a Rate Analyst in the Rates and Business Support Department. Since joining Consumers Energy, I have been responsible for completing cost-of-service and revenue requirements studies. I joined the Sales Forecasting team in July 2015, and now perform sales forecasting duties.

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

A. Yes, I provided testimony and exhibits in these and other Consumers Energy cases: Case Nos. U-15645, U-16191, U-16794, U-17087, U-17643, U-17943, U-18124, U-18151, U-18411, U-18424, U-20233, U-20322, U-20650, U-21062, U-21148, U-21269 and U-21308.

Q. Please explain the purpose of your direct testimony in this proceeding.

A. I am presenting the Company's forecasted gas delivery and customer count levels used to design test year rates in this case. I will discuss the observed historic gas deliveries, customer counts, and operating revenues. My direct testimony will address the development of the forecasts used in this case.

Q. Are you sponsoring any exhibits in this case?

A. Yes. I am providing the following exhibits:

Exhibit A-5 (EJK-1)	Schedule E-1	Annual Service Area Sales by Major Customer Classes and System Output 5-Year Historical;
Exhibit A-5 (EJK-2)	Schedule E-1a	Summary of 2022 Historical Year Revenues;
Exhibit A-5 (EJK-3)	Schedule E-2	2022 Historical Year Consumption and Customer Counts;
Exhibit A-5 (EJK-4)	Schedule E-3	2022 Historical Year Operating Revenues;
Exhibit A-15 (EJK-5)	Schedule E-1	Market Outlook: 5-Year Annual Calendar Gas Forecast by Class;
Exhibit A-15 (EJK-6)	Schedule E-2	Test-Year Calendar Gas Deliveries Forecast by Class;
Exhibit A-15 (EJK-7)	Schedule E-3	Test-Year Calendar Gas Deliveries by Rate Schedule;

Exhibit A-15 (EJK-8)	Schedule E-4	Test-Year Authorized Tolerance Levels by Rate Schedule;
Exhibit A-15 (EJK-9)	Schedule E-5	Market Outlook: 5-Year Average Customer Forecast by Class;
Exhibit A-15 (EJK-10)	Schedule E-6	Test-Year Customer Count Forecast by Class;
Exhibit A-15 (EJK-11)	Schedule E-7	Test-Year Total Customer Count Forecast by Rate Schedule;
Exhibit A-15 (EJK-12)	Schedule E-8	Calculation of Test-Year Projected Income Assistance Enrollments;
Exhibit A-15 (EJK-13)	Schedule E-9	Calculation of Test-Year Excess Peak Consumption; and
Exhibit A-15 (EJK-14)	Schedule E-10	Transition from 2022 Historic Actuals to 12 Months Ending September 2025 Test-Year Revenues, Deliveries, and Customers.

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

A. Yes.

Q. Please explain the current weather normalization process?

A. The Company contracted with Itron to develop a set of economic models to quantify the weather affects. The models developed by Itron take into consideration the various weather responses by rate class (residential, commercial, and industrial), customer counts, weather trends, billing days, and responses at various temperature levels (55 degrees Fahrenheit versus 65 degrees Fahrenheit).

Q. How well do the econometric models explain the observed variations in gas deliveries?

A. Six main econometric models are used to explain the variation in gas delivery by class (residential, commercial, and industrial) and service type (sales and transportation). For instance, the total variation in residential gas deliveries due to temperature is explained using a residential sales model and residential transportation model. Similar models are used for commercial and industrial gas deliveries. The model is robust and performs well in explaining the variation in gas deliveries.

Q. How accurate was this weather normalization process in 2022?

A. Our weather adjusted calendar deliveries for 2022 totaled approximately 308.7 Bcf, compared to our budgeted calendar deliveries of approximately 310.1 Bcf, or roughly 0.5% below our anticipated deliveries.

Q. Please explain Exhibit A-5 (EJK-1), Schedule E-1.

A. Exhibit A-5 (EJK-1), Schedule E-1, is a summary of the five-year Historical Annual Service Area Sales by Major Customer Classes and System Output. This exhibit is filed in accordance with the Commission's directive in Case No. U-18238.

Q. Please provide a summary of the 2022 operating revenue based on the actual customer and gas delivery levels for the historical year.

A. The 2022 historical operating revenue is presented in Exhibit A-5 (EJK-2), Schedule E-1a, by rate schedule. A detailed summary of customer counts and deliveries is provided in Exhibit A-5 (EJK-3), Schedule E-2, by rate schedule and type of service (sales, customer choice, transportation, and aggregation). The components of the 2022 historical operating revenues are shown in Exhibit A-5 (EJK-4), Schedule E-3. These exhibits are also filed in accordance with the Commission's directive in Case No. U-18238.

Q. Please summarize Consumers Energy's gas forecasting process.

A. In general, the gas forecasts are based on regression analysis, a mathematical and statistical technique that correlates the relationship between dependent variables (deliveries and customer counts) and independent variables (economics and/or weather). Applying these relationships to expected independent variables allows the Company to project the corresponding movements in dependent variables. The four major classes of gas deliveries (sales plus transportation) that are forecast are residential, commercial, industrial, and interdepartmental. For each of these classes, monthly forecasts are developed on a cycle billed (billing month) basis and then adjusted to calendar month amounts using the methodology described later in my direct testimony. Moreover, the impact of exogenous factors – e.g., incremental energy efficiency – is applied ex post.

Q. Please describe the different models used to develop the gas deliveries and customer count forecasts.

A. Regression analysis is used to develop forecast models that estimate numerical coefficients applied to weather and economic indicators to estimate future gas consumption. The regression models were evaluated against various measures to ensure that reasonable forecasts were generated. For instance, each model was reviewed to validate that the drivers were theoretically sound, model coefficients were statistically significant, and model variables explained historical and current market conditions.

Q. Please briefly describe the economic data used in the forecast process.

A. Historical and projected service sector employment and manufacturing employment are included as independent variables in the forecasting process. These indicators are from the forecasts of Michigan economic activity obtained from IHS Markit.

Q. Please briefly describe the weather data used in the forecast process.

A. The gas delivery forecasts assume normal weather based on the 15-year mean. Under this method, the daily temperature is used to calculate monthly heating degree days. The

15-year mean of the monthly heating degree days is then used to represent future expected weather impacts.

Q. Why does the Company use the regression model approach to forecast sales?

A. Regression modeling has been approved by the Commission in Case Nos. U-17643, U-17882, U-18124, U-18424, U-20322, U-20650, U-21148 and U-21308. Regression analysis is a statistical process used to predict an outcome based on the relationship between a dependent variable (deliveries, average usage, or customers) and independent variable(s) (weather and economy). For instance, a regression model is used to predict average residential monthly usage based primarily on future expectations of normal weather occurring during the test year. Each model is evaluated for reasonableness – i.e., is it theoretically logical – and statistical significance as part of the forecasting process. Regression analysis is used to develop gas delivery and customer count forecast models based on weather and economic variables. Each model is selected based on its ability to properly explain variations in historical data – i.e., how well it fits the data – along with the statistical significance of the model coefficients. Particularly, I evaluate regression model performance based on the adjusted coefficient of multiple determination (R_a^2) and Mean Absolute Percent Error ("MAPE"). In addition, I also examine the t-statistics and p-values associated with the model coefficients.

Q. Please explain the use of R_a^2 and MAPE.

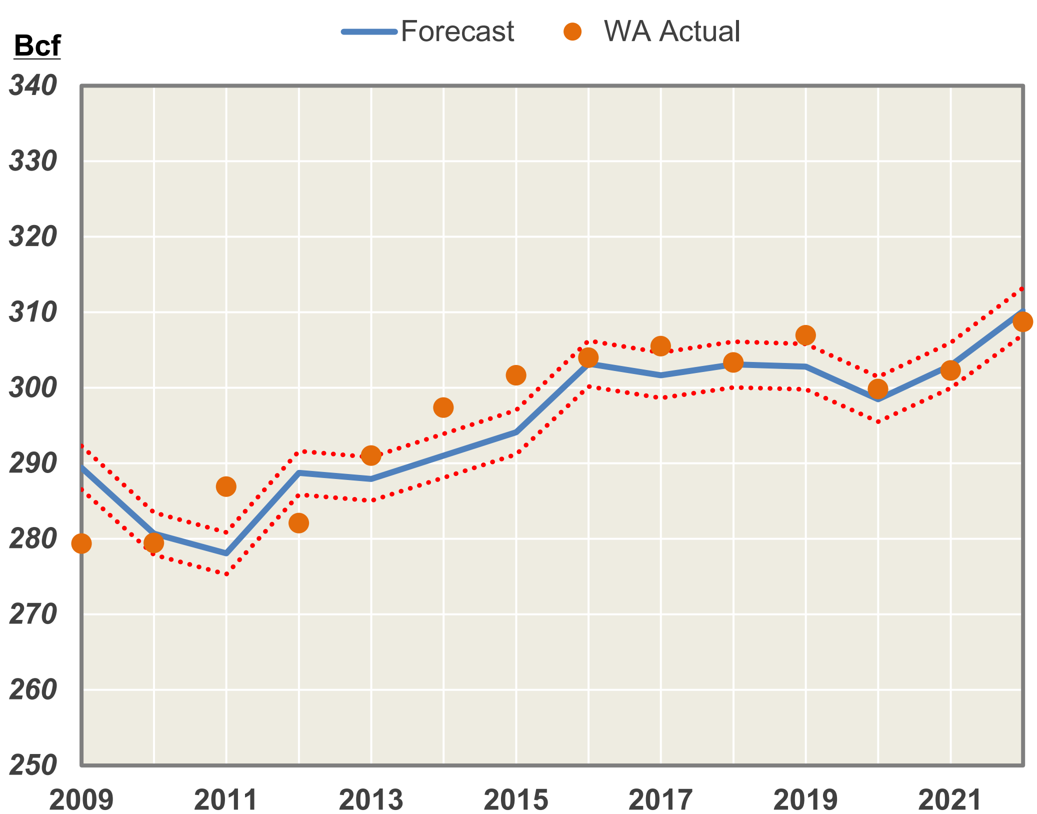
A. Both of these statistical tests are used to evaluate how well the models fit the historical data, and also provide a good indication of how well the models will perform in the forecast period. The R_a^2 measures the ability of the models to explain variations in the historical data. An R_a^2 of unity suggests that a model explains all of the variations in the data whereas an R_a^2 of zero suggests it explains none of the variations. For example, if regression models have R_a^2 values above 0.9, this suggests that at least 90% of the variation in the data is explained by the models. In most cases, the models used in the Company's forecasting process have values in excess of 0.95. In addition, I consider the MAPE values to gauge overall model performance. Essentially, the MAPE is used to measure the model errors in which smaller values suggest better model performance. MAPE values between 5% and 10% are generally considered ideal, although higher values may also be deemed acceptable based on other considerations, such as the R_a^2. The regression models used in the Company's forecasting process generally have MAPE values below 10%.

Q. Please explain the criteria used when considering the t-statistics and p-values associated with the model coefficients.

A. Regression analysis is used to develop models that minimize the variance between the actual data and estimates from the models based on the relationship between dependent and independent variables. A numerical coefficient (β) is estimated for each independent variable in the model and represents the best linear unbiased estimate for that variable's contribution toward explaining the dependent variable. The t-statistics and p-values are used to gauge the relevance of each independent variable in the model. The t-statistics and p-values measure the statistical significance of including a particular independent variable based on a probability distribution. A t-statistic above 2 and p-value below 5% for a particular β suggests the independent variable is statistically significant and is appropriate to include in the regression model. Independent variables with t-statistics below 2 and p-values above 5% suggest the variable should be excluded from the model since it does little to explain the dependent variable. In addition, I also consider the direction (positive or negative coefficient sign) and magnitude of each coefficient when determining to include or exclude variables from the models.

Q. You claim the regression model approach produces superior results. How accurate has the Company's forecast been historically?

A. The Company's forecast accuracy can be seen in the graph below. The standard deviation from 2013 through 2022 is 4.0 Bcf and the MAPE is only 1.0%.



Q. What is the forecast of natural gas deliveries for the test year and five-year outlook?

A. Total calendar deliveries are expected to increase slightly from historic weather normal actuals of 308.7 Bcf in 2022 through the test year. Over the next five years, total deliveries are projected to increase to 311.3 Bcf by 2028. However, the growth or loss in gas deliveries is not symmetric across all classes. The total and class level gas delivery annual forecasts for 2024 through 2028 are provided in Exhibit A-15 (EJK-5), Schedule E-1.

Exhibit A-15 (EJK-6), Schedule E-2, provides the 12 months ending September 2025 test year 15-year calendar weather normalized deliveries on a monthly basis, by class, in accordance with Commission filing requirements.

Q. Please explain the process used to separate the test year deliveries by rate schedule.

A. The test year forecast is allocated to the various rate schedules based on the 2022 historical deliveries. The results of the allocation process are provided in Exhibit A-15 (EJK-7), Schedule E-3, and Exhibit A-15 (EJK-8), Schedule E-4.

Q. Please describe the forecast of customer count levels in the test year and five-year outlook.

A. Total customer counts are projected to increase 1.6% from 1,815,156 in 2022 to 1,844,628 in the 12 months ending September 2025 test year. Over the next five years, the customer level is expected to increase 0.6% per annum with most of this growth occurring within the residential class. The total and class level forecasts are provided in Exhibit A-15 (EJK-9), Schedule E-5, and Exhibit A-15 (EJK-10), Schedule E-6.

Q. Please describe the process used to separate the customer forecasts by rate schedule.

A. The test year customer forecast is allocated to the various rate schedules based on the 2022 historical customer count levels. The results of the allocation process are provided in Exhibit A-15 (EJK-11), Schedule E-7.

Q. Please discuss the process used to forecast the level of consumption and customers enrolled in the Company's income assistance program.

A. The number of expected enrollments is 90,000 customers per month based on the 12-month average of the most recent history. The average residential usage for the test year is applied to this level of customers to develop the consumption set forth in Exhibit A-15 (EJK-12), Schedule E-8.

Q. Please describe the process used to forecast the level of excess peak demand.

A. The test year excess peak demand consumption associated with residential multi-dwelling service is based on the peak month consumption and customer levels in accordance with the Company's natural gas tariffs and is provided in Exhibit A-15 (EJK-13), Schedule E-9.

Q. Please provide a summary of the change in revenues, customers, and gas deliveries from the 2020 historical year to the test year.

A. Exhibit A-15 (EJK-14), Schedule E-10, provides a summary of the change in revenue, customer levels, and gas deliveries from the 2022 historical year to the 12 months ending September 2025 test year.

Q. Does this conclude your direct testimony?

A. Yes.

S T A T E O F M I C H I G A N

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter 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-21490

REDACTED

DIRECT TESTIMONY

OF

YONG F. KEYES

ON BEHALF OF

CONSUMERS ENERGY COMPANY

December 2023

Q. Please state your name and business address.

A. My name is Yong F. Keyes, and my business address is One Energy Plaza, Jackson, Michigan 49201.

Q. By whom are you employed?

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

Q. What is your position with Consumers Energy?

A. I am a Senior Rates Analyst in the Cost and Pricing Section of the Rates and Regulation Department.

Q. Please state your educational background and work experience.

A. I earned the degree of Bachelor of Science in Information Engineering Technology from the University of Cincinnati, graduating Magna Cum Laude in 2002. In April 2002, I joined Consumers Energy as a Programmer Analyst developing Lotus Notes databases. From September 2004 through March 2010, I was a Technical Analyst for Business Services, responsible for managing Real Estate's document management systems and performing System Administrator functions. In December 2009, I earned the degree of Master of Business Administration from Eastern Michigan University with a concentration in Finance. In April 2010, I accepted a position as a Business Support Consultant in the Wholesale Settlement section of Energy Supply Operations, responsible for monthly forecasts for the Company's Transmission and Midcontinent Independent System Operator, Inc. market expenses. In December 2015, I joined the Renewable Energy Section where I was responsible for renewable energy credit ("REC") forecasting, inventory management, and administration. In October 2021, I accepted my current position in the Rates and Regulation Department.

Q. Have you previously filed testimony with the Michigan Public Service Commission ("MPSC" or the "Commission")?

A. Yes. I filed testimony on behalf of the Company in the following proceedings before the Commission:

- Case No. U-18231, Consumers Energy's 2017 Amended Renewable Energy Plan ("RE Plan");
- Case No. U-18241, Consumers Energy's 2016 Renewable Energy Cost Reconciliation;
- Case No. U-20171, Consumers Energy's 2017 Renewable Energy Cost Reconciliation;
- Case No. U-20483, Consumers Energy's 2018 Renewable Energy Cost Reconciliation;
- Case No. U-20722, Consumers Energy's 2019 Renewable Energy Cost Reconciliation;
- Case No. U-20984, Consumers Energy's 2021 Amended RE Plan;
- Case No. U-21009, Consumers Energy's 2020 Renewable Energy Cost Reconciliation;
- Case No. U-21205, Consumers Energy's 2021 Energy Waste Reduction ("EWR") Reconciliation; and
- Case No. U-21308, Consumers Energy's 2022 Gas Rate Case.

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

A. The purpose of my direct testimony is to present the Company's gas Cost-of-Service Study ("COSS") for the 12-month period ending September 30, 2025 ("test year").

Q. Is the Company proposing any changes to the COSS methodologies previously approved by the Commission?

A. Yes. Because the Company is proposing changes to the COSS methodologies approved by the Commission in prior cases, in accordance with the Commission's rate case filing requirements established in Case No. U-18238, the Company is sponsoring two versions of the COSS. The first COSS (Version 1) employs the methodologies previously adopted by the Commission in Case No. U-20650 updated for the financial information and supporting data sponsored by other witnesses in this case. The second COSS (Version 2) starts with the Version 1 COSS and incorporates three Company proposals that are responsive to issues or topics raised in Case No. U-21308. The Company is proposing to: (1) remove Asset Retirement Costs ("ARC" or the Asset Retirement Obligation "ARO") from the calculation of other distribution plant; (2) break out and allocate other distribution plant by FERC account; and (3) breakout and separately allocate Customer Care Center ("CCC") and the Business Customer Care ("BCC") expenses. The Company's proposal to breakout other distribution plant by FERC account complies with the settlement agreement in Case No U-21308.

In addition to COSS Version 1 and COSS Version 2, the Company is presenting two additional COSSs for informational purposes as agreed upon in the Company's settlement agreement in Case No. U-21308. The first replaces Average & Peak ("A&P) methods with Average & Excess ("A&E") as proposed by the Association of Businesses Advocating Tariff Equity ("ABATE") in Case No U-21308 (Exhibit A-86 (YFK-3)). The second uses an allocator developed using the balance of High Pressure ("HP") and Non-High Pressure ("Non-HP") distribution plant to allocate other distribution plant (Exhibit A-87 (YFK-4)). The Company is not advocating that the Commission adopt either of these methods in its final COSS in this case. The Company recommends adoption of COSS Version 2 for setting rates in this case.

Q. Are you sponsoring any exhibits?

A. Yes, I am sponsoring the following exhibits:

Exhibit A-16 (YFK-1)	Schedule F-1	Gas Cost-of-Service Study – Version 1 - Projected 12 Month Period: October 2024 – September 2025; and
Exhibit A-16 (YFK-2)	Schedule F-1.1	Gas Cost-of-Service Study – Version 2 - Projected 12 Month Period: October 2024 – September 2025;
Exhibit A-86 (YFK-3)		Gas Cost-of-Service Study – Average & Excess;
Exhibit A-87 (YFK-4)		Gas Cost-of-Service Study – High Pressure/Non-High Pressure;
Confidential Exhibit A-88 (YFK-5)		Gas Cost-of-Service Study – [redacted];
Exhibit A-89 (YFK-6)		Gas Cost-of-Service Study – ABATE Witness Jonathan Ly's Exhibit AB-15 (Average & Excess) Case U-21308; and
Exhibit A-90 (YFK-7)		Gas Cost-of-Service Study – ABATE Witness Jonathan Ly's Direct Testimony Page 12 (Average & Excess) Case U-21308.

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

A. Exhibits A-16 (YFK-1), Schedule F-1; A-16 (YFK-2), Schedule F-1.1, A-86 (YFK-3), A-87 (YFK-4) and Confidential Exhibit A-88 (YFK-5) were all prepared by me or under my direction and supervision. Exhibits A-89 (YFK-6) and A-90 (YFK-7) were drawn from Company records kept in the ordinary course of business of the testimony and exhibits submitted in Consumers Energy's last gas rate case, Case No. U-21308.

Q. How is your direct testimony organized?

A. My direct testimony is organized as follows:

I. COST OF SERVICE OVERVIEW

Q. What is COSS?

A. A COSS is a three-part analysis that quantifies the utility's cost to serve each rate class. It provides the utility and stakeholders with important information regarding each rate class's contribution to the total revenue requirement and the nature of those costs. Ultimately, the information provided by the COSS is used to guide rate design among other things. The fundamental guiding principle used to assign costs in the COSS is cost causation. In other words, the costs assigned to a customer or group of customers should reflect how those customers drive or influence the utility's costs.

Q. What are the three parts or steps involved in performing a COSS?

A. The first step is functionalization, followed by classification, and finally allocation. Cost functionalization involves the identification and separation of plant and expenses into specific categories based on the activity or "function" that each cost is incurred to provide or support. Consumers Energy's functional cost categories are Transmission, Distribution, and Storage. Cost classification, the second step, involves the categorization of functionalized costs into demand, customer, and energy components according to the primary cost drivers. The final step is cost allocation. Allocation assigns costs to each customer class using a variety of factors that correlate to the identified cost drivers. Common allocation factors include the number of customers, throughput or usage, and peak consumption among others. This process is relatively standard across the utility industry and supported by the National Association of Regulatory Utility Commissioners ("NARUC") Gas Distribution Rate Design Manual.

II. <u>TEST YEAR COST OF SERVICE - VERSION 1</u>

Q. Please describe Exhibit A-16 (YFK-1), Schedule F-1.

A. Exhibit A-16 (YFK-1), Schedule F-1, is a 16-page exhibit that summarizes the results of the Version 1 COSS. As explained earlier in my testimony, the Version 1 COSS employs the methodologies previously adopted by the Commission in Case No. U-20650 updated for the financial information and supporting data sponsored by other witnesses in this case. The Company also made routine updates for historical and test year data that are used to derive COSS cost detail and the various functional, classification, and allocation factors.

Page 1 of the exhibit summarizes the results of the COSS; total Company gas information for the test year is found in column (d) while columns (e) through (l) breakout the cost to serve for each rate class. Total rate base by rate is shown on line 33 with the return on rate base shown on line 37. Adjusted net operating income is shown on line 32 and is calculated by subtracting test year total expenses from revenue, adjusting for Allowance for Funds Used During Construction. The associated income and revenue deficiencies are shown on lines 41 and 42 respectively and are supported by Company witness Heather L. Rayl. The proposed base rate design revenue target for each rate class, which is shown on line 46, is found by removing Cost of Goods Sold and miscellaneous revenue from the total cost of service. Page 2 provides a breakout of the proposed base rate design revenue target by rate class for each functional cost category (transmission, storage, and distribution).

Exhibit A-16 (YFK-1), Schedule F-1, pages 3 through 10, provide detail on rate base, O&M, and revenue that supports the summary information presented on Exhibit A-16 (YFK-1), Schedule F-1, pages 1 and 2. Exhibit A-16 (YFK-1), Schedule F-1, pages 11 through 16, support the functionalization, classification, and allocation factors utilized in the COSS.

III. TEST YEAR COST OF SERVICE - VERSION 2

Q. Please describe Exhibit A-16 (YFK-2), Schedule F-1.1 and explain how it differs from the Version 1 COSS (Exhibit A-16 (YFK-1), Schedule F-1).

A. Exhibit A-16 (YFK-2), Schedule F-1.1 is a 16-page exhibit that starts with the Version 1 COSS (Exhibit A-16 (YFK-1), Schedule F-1) and incorporates the three Company proposals cited earlier in my testimony to: (1) remove ARC from the calculation of other distribution plant; (2) break out and allocate other distribution plant by FERC account, and (3) breakout and separately allocate CCC and BCC expenses. The page and line references in the Version 1 COSS also apply to Version 2. A summary of the results of the Version 2 COSS results and how it compares to Version 1 for each rate class is shown in Table 1.

Table 1: Summary of COSS Impact by Rate ($ in Millions)

Description	Total	Residential	Rate GS-1	Rate GS-2	Rate GS-3	Rate ST	Rate LT	Rate XLT	Rate XXLT
Present Revenue	$ 1,513	$ 1,088	$ 159	$ 119	$ 27	$ 39	$ 31	$ 35	$ 15
Version 1 Update	$ 136	$ 92	$ 31	$ 10	$ 4	$ (2)	$ (3)	$ 1	$ 4
Version 1 COSS	$ 1,649	$ 1,180	$ 190	$ 128	$ 31	$ 36	$ 28	$ 36	$ 19
	9.0%	8.5%	19.4%	8.0%	13.6%	-6.4%	-8.9%	2.0%	27.8%
+Remove ARC	$ -	$ 7.0	$ (0.5)	$ (1.6)	$ (0.4)	$ (0.7)	$ (0.8)	$ (1.8)	$ (1.2)
+Other Dist. FERC	$ -	$ 1.6	$ (0.1)	$ (0.3)	$ (0.1)	$ (0.1)	$ (0.2)	$ (0.5)	$ (0.3)
+BCC/CCC	$ -	$ 3.0	$ (0.1)	$ (1.1)	$ (0.4)	$ (0.5)	$ (0.4)	$ (0.4)	$ (0.2)
Version 2 COSS	$ 1,649	$ 1,192	$ 190	$ 125	$ 30	$ 35	$ 27	$ 33	$ 17
	9.0%	9.6%	19.0%	5.5%	10.4%	-9.8%	-13.4%	-5.7%	16.1%

A) Asset Retirement Costs

Q. Please explain why the Company is proposing to remove ARC from other distribution plant.

A. The Company is proposing to remove ARC from the COSS calculation of other distribution plant because these costs are not included in the distribution plant revenue requirement. The Company made the same proposal in Case No. U-21308 which was not contested by any party in that case and was adopted in the settlement COSS.

As shown in Table 2, removing ARC decreases the percentage of distribution plant categorized as other distribution plant from 8.56% to 5.54% and increases the share of plant in other categories.

Table 2: Comparison of Distribution Plant Major Categories

Distribution Plant Major Categories	Version 1	Version 2
Distribution Plant - Other	8.56%	5.54%
Mains - High Pressure Capable	5.29%	5.47%
Mains - Non-High Pressure Capable	26.68%	27.56%
Services & Meters	59.47%	61.44%

B) Breakout of Other Distribution Plant by FERC Account

Q. Please explain how the COSS has treated other distribution plant in the past.

A. Historically, the Company has allocated other distribution plant using Allocator 105. It includes volumes from customers attached to HP mains and customers attached to non-HP mains with an adjustment that removes volumes that bypass the HP system. In Case Nos. U-21148 and U-21308 the Company proposed using Allocator 104 in place of Allocator 105 since Allocator 104 is based on total annual throughput and peak month throughput.

Q. Please explain why the Company is proposing to break out other distribution plant in this case.

A. In Case No. U-21308 ABATE witness Jonathon Ly argued it is not appropriate for other distribution plant be allocated in aggregate because the accounts included serve different functions. In rebuttal, the Company agreed to breakout other distribution plant costs on a more detailed FERC account basis in the next rate case which was formally reflected in Case No. U-21308 settlement agreement.

Q. What FERC accounts are included in other distribution plant?

A. Other distribution plant includes costs in FERC accounts 374, 375, 377, 378 and 382 where:

- Account 374 Land & Land Rights includes cost of land and land rights used in connection with distribution operations. The attainment of Land and Land Rights (Fee Land or Right of Way Easement) for roads or driveways, regulator stations, and tree rights is the foundation to lay down the Company's distribution system.
- Account 375 Structures and Improvements includes cost of structures and improvements used in connection with distribution operations. Structures and improvements to Gas Boiler Building, Gas Odorizing Station Building, Gas Regulator Building, etc. are critical to the safe and reliable operations of the Company's distribution system. They benefit all customers.

- Account 377 Compressor station equipment includes costs of installed compressor station equipment and associated appliances used in connection with distribution system operations. Air Compressors, Detectors, Sensors, Transformers, Transmitters, Valves, Uninterruptible Power Supplies etc. are critical to the safe and reliable operations of the Company's distribution system. They benefit all customers.
- Account 378 Measuring and regulating station equipment - Generally includes costs of installed meters, gauges and other equipment used in measuring and regulating gas in connection with distribution system operations other than the measurement of gas deliveries to customers. They are critical to the safe and reliable operations of the Company's distribution system. They benefit all customers.
- Account 382 Meter installations includes cost of labor and materials used and expenses incurred in connection with the original installation of customer meters. Examples include installations of meters, rotary meters, meter regulator bypasses, Gas Sampler, etc.

Q. How is the Company proposing to allocate other distribution plant for FERC Accounts 374, 375, 377, and 378?

A. The Company proposes to allocate other distribution plant using Allocator 104 for FERC Account 374, 375, 377, 378. Costs in these FERC accounts, as described above, are incurred to serve all customers. Since Allocator 104 is based on each rate class's respective forecasted total annual throughput and peak month throughput, the Company believes it is an improvement over allocator 105 which excludes volumes that bypass the HP system.

Q. How is the Company proposing to allocate other distribution plant for FERC Accounts 382?

A. The Company proposes to allocate other distribution plant using Allocator 108 for FERC Account 382. Costs in this FERC account, as described above, are incurred in connection with the original installation of customer meters. Since Allocator 108 is weighted by the average residential customer hook up cost and is based on each rate class's respective forecasted average number of customers, the Company believes it is an improvement over allocator 104 which is based on each rate class's respective forecasted total annual throughput and forecasted peak month throughput.

C) Customer Care Center and Business Customer Care Expense

Q. How have CCC and BCC costs been allocated to customers in the past?

A. Historically, CCC and BCC costs were included in the COSS line item "O&M Excluding A&G" which gets divided among several sub-categories using historic ratios and assigned a variety of allocators.

Q. How is the Company proposing to allocate CCC and BCC costs in Version 2 of the COSS?

A. The Company has broken out CCC and BCC costs as separate line items in the COSS and developed two new allocators, allocator 114 which calculates the share of customers (by rate class) using the BCC and allocator 115 which calculates the share of customers (by rate class) using the CCC. Generally speaking, the CCC serves residential and small business customers while the BCC serves commercial and industrial customers. Because business customers may utilize the CCC or BCC, the Company obtained data on the number of customers by rate class served by the BCC as a reasonable measure of resource utilization and cost causation. This data was then used to calculate both allocators 114 and 115. Support for these calculations can be found in WP-YFK-25.

IV. IMPACT OF UTILIZING THE A&E METHOD

Q. Please explain why the Company is presenting the A&E method in this case.

A. In the Case No. U-21308 settlement agreement the Company agreed to provide a COSS that calculated the impact of utilizing the A&E method. The COSS results using the A&E method can be found in Exhibit A-86 (YFK-3).

Q. Please explain how A&E method is calculated.

A. The A&E method is comprised of two components. The first component is based on average annual throughput weighted by a utility's system load factor. The second component only considers the amounts for each classes' load over and above its average demand. To calculate the A&E method in this case, the Company relied on the A&E method developed in ABATE witness Ly's Direct Testimony (specifically at page 12 of his testimony) and Exhibits (specifically ABATE Exhibit No. AB-15) in Case No U-21308. The calculation can be found in WP-YFK-23. Mr. Ly's Direct Testimony from Case No. U-21308 (Page 12) can be found in Exhibit A-90 (YFK-7). Mr. Ly's Exhibit No. AB-15 from Case No. U-21308 can be found in Exhibit A-89 (YFK-6).

Q. What is the impact of utilizing the A&E method on the COSS results?

A. Table 3 shows how the results of the A&E COSS compare to the results of the Version 2 COSS:

Table 3: A&E COSS Impacts by Rate Class ($ in Millions)

Description	Total	Residential	Rate GS-1	Rate GS-2	Rate GS-3	Rate ST	Rate LT	Rate XLT	Rate XXLT
Version 2 COSS	$ 1,649	$ 1,192	$ 190	$ 125	$ 30	$ 35	$ 27	$ 33	$ 17
A&E COSS	$ 1,649	$ 1,207	$ 198	$ 130	$ 29	$ 30	$ 20	$ 26	$ 10
Difference	$ -	$ 15	$ 8	$ 4	$ (1)	$ (5)	$ (7)	$ (7)	$ (7)
	0.0%	1.2%	4.3%	3.6%	-2.0%	-15.4%	-25.6%	-22.5%	-41.4%

Q. Is the Company proposing to adopt the A&E method?

A. No. While the Company believes the A&E method is reasonable and makes some improvements to the A&P method, the Commission has consistently ruled in favor of using the A&P method to allocate distribution mains costs in Case No. U-10150, Case No. U-18124, and Case No. U-20322, to name a few.

V. IMPACT OF ALLOCATING OTHER DISTRIBUTION PLANT BETWEEN HP AND NON-HP

Q. Please explain why the Company is presenting the impact of separately breaking out and allocating other distribution plant between HP and Non-HP.

A. In the Case No. U-21308 settlement agreement the Company agreed to provide a COSS that allocates other distribution plant between HP and Non-HP. The COSS results using this method can be found in Exhibit A-87 (YFK-4).

Q. How did the Company break out other distribution plant between HP and Non-HP?

A. The Company used the method developed by Lansing Board of Water and Light/Michigan State University witness Timothy S. Lyons in Case No. U-21308. Other distribution plant is first functionalized to HP Mains (16.55%) and Non-HP mains (83.45%) based on their relative costs and then allocated to each rate class based on a weighted average of HP Mains Allocator (A&P Allocator 105) and Non-HP Mains allocator (A&P Allocator 106). The result of this calculation is a new allocator 217 that was applied to other distribution plant. Support for these calculations can be found in WP-YFK-24.

Q. What is the impact of using this method to allocate other distribution plant?

A. Table 4 shows how the results of the HP/Non-HP COSS compare to the results of the Version 2 COSS:

Table 4: HP/Non-HP COSS Impacts by Rate Class ($ in Millions)

Description	Total	Residential	Rate GS-1	Rate GS-2	Rate GS-3	Rate ST	Rate LT	Rate XLT	Rate XXLT
Version 2 COSS	$ 1,649	$ 1,192	$ 190	$ 125	$ 30	$ 35	$ 27	$ 33	$ 17
HP/Non-HP COSS	$ 1,649	$ 1,194	$ 190	$ 126	$ 30	$ 35	$ 26	$ 31	$ 16
Difference	$ -	$ 2	$ 1	$ 1	$ 0	$ 0	$ (0)	$ (2)	$ (2)
	0.0%	0.2%	0.3%	0.5%	0.3%	0.5%	-1.0%	-5.8%	-8.8%

Q. Is the Company proposing to adopt the HP/Non-HP method to allocate other distribution cost?

A. No. The Company's Version 2 COSS already breaks out other distribution plant on a FERC account basis and assigns appropriate allocators for each account. The break-out by FERC account is more granular than breaking out by HP versus non-HP Mains in determining the cost drivers for each FERC account.

VI. [redacted]

[redacted]

Q. Does this complete your direct testimony?

A. Yes.

S T A T E   O F   M I C H I G A N

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter 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-21490

REDACTED

DIRECT TESTIMONY

OF

STEVEN Q. MCLEAN

ON BEHALF OF

CONSUMERS ENERGY COMPANY

December 2023

Q. Please state your name and business address.

A. My name is Steven Q. McLean, and my business address is One Energy Plaza, Jackson, Michigan 49201.

Q. By whom are you employed and what is your present position?

A. I am employed by Consumers Energy Company ("Consumers Energy" or the "Company") as the Director of Customer Regulatory and Compliance in the Customer Strategy and Data Analytics Department.

Q. Please review your educational background.

A. I earned a Bachelor of Science in Political Science and Economics from Central Michigan University in May 2003. I earned a Master of Arts in Economics from Central Michigan University in December 2007.

Q. Please review your business experience.

A. In January 2006, I joined the Michigan Public Service Commission ("MPSC" or the "Commission") where I held various positions of increasing responsibility. In 2011, I was promoted to the Manager of the Rates and Tariffs section. The responsibilities of that section included, but were not limited to, analyzing utility reports, financial records, and rate case filings to determine the appropriate level of rates for regulated energy utilities utilizing laws, regulations, and Commission policies. In August of 2014, I was hired by SEMCO Energy Gas Company ("SEMCO") as the Rates and Regulatory Affairs Manager. In December of 2016, I was promoted to Director of Regulatory Affairs. As Director of Regulatory Affairs, I was responsible for all state and federal regulatory matters for SEMCO. In addition, I was responsible for SEMCO's Energy Waste Reduction ("EWR") Program. In September of 2019, I was hired by Consumers Energy as the Director of

Customer Experience Regulatory Strategy, Reporting and Quality within the Clean Energy Department, and in October 2021, I was promoted to Director of Customer Regulatory and Compliance.

Q. What are your responsibilities as the Director of Customer Regulatory and Compliance?

A. In this position, I am responsible for coordinating the regulatory filing and planning processes associated with the Company's EWR Plans, Renewable Energy Voluntary Green Pricing programs, and Demand Response ("DR") programs. In addition, I am responsible for corporate compliance within the Customer Experience and Customer Operations departments.

Q. Have you previously testified before the MPSC?

A. Yes. I testified in the Company's general rate cases, Case Nos. U-20650, U-20697, U-21148, and U-21224; the Company's 2019 and 2020 DR Reconciliations, Case Nos. U-20766 and U-21080, respectively; the Company's 2021 Integrated Resource Plan ("IRP"), Case No. U-21090; and the Company's 2021 EWR Plan, Case No. U-20875. Additionally, I have testified before the MPSC in numerous general rate cases, Gas Cost Recovery cases, EWR cases, and other miscellaneous proceedings on behalf of the MPSC Staff ("Staff") and SEMCO.

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

A. The purpose of my direct testimony is to describe the Customer Experience and Operations ("CX&O") organization and how the work performed within this organization benefits the Company's residential and business gas customers today and into the future. As part of my direct testimony, I will address the operating and maintenance ("O&M")

expenses and capital investments associated with executing this work in the test year ending September 2024. [redacted]

Q. Are you sponsoring any exhibits?

A. Yes, I am sponsoring the following exhibits:

Exhibit A-12 (SQM-1)	Schedule B-5.8	Actual and Projected Capital Expenditures – Customer Experience & Operations;
Exhibit A-91 (SQM-2)		Summary of Actual & Projected O&M Expenses – Customer Experience & Operations; and
Confidential Exhibit A-92 (SQM-3)		[redacted]
Confidential Exhibit A-93 (SQM-4)		[redacted]

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

A. Yes.

Q. Please describe Exhibit A-12 (SQM-1), Schedule B-5.8.

A. Exhibit A-12 (SQM-1), Schedule B-5.8, details the capital expenditures related to direct work within the CX&O organization, which total $501,558 in historical and $275,753 for the projected bridge period ending September 30, 2024. This reflects a financial forecast based on the work plan and designated development activities for each Customer area.

Please note that this testimony also discusses the Customer benefit of the capital spend sponsored by the IT Company witness Stacy H. Baker.

Q. Please describe Exhibit A-91 (SQM-2).

A. Exhibit A-91 (SQM-2) details the O&M expenses related to work within the CX&O organization, which total $33,670,828 for the test year ending September 30, 2025.

Q. Please describe Exhibit A-91 (SQM-2), page 4.

A. Exhibit A-91 (SQM-2), page 4, presents the amounts of the projected O&M expenses that were developed by applying either an inflation rate or a merit increase rate to historical O&M expense. Column (b) shows the historical O&M expense. Column (c) shows the historical amount to which an inflation rate or merit increase rate was applied. Columns (e) and (g) show the amounts to which an inflation rate or merit increase rate were applied for each bridge period, respectively. Columns (d), (f), and (h) show the merit and inflation increases for each respective period. Amounts that were projected using other methods are included in column (i). Column (j) is the projected test year O&M and is the sum of columns (b), (d), (f), (h), and (i).

Q. Please describe Confidential Exhibit A-92 (SQM-3) and Confidential Exhibit A-93 (SQM-4).

A. [redacted]

[redacted]

Q. Please provide a summary of the CX&O O&M expenses and capital investments projected in the test year.

A. CX&O is projecting a total of $777,312 in historical and bridge year capital expense, as mentioned above, and $33.7 million in O&M expense for the test year ending September 30, 2025. This amount comprises $24.1 million of O&M expenses for Customer Interactions, and $9.6 million for Billing and Payment. The CX&O O&M expenses are presented in detail on Exhibit A-91 (SQM-2). The historical and projected capital costs for these programs are included in Exhibit A-12 (SQM-1), Schedule B-5.8.

DEPARTMENT	CAPITAL	O&M
Customer Interactions	$0.692 million	$24.1 million
Billing & Payment	$0.086 million	$9.6 million
Total	**$0.777 million**	**$33.7 million**

The Company is also projecting $1,292,439 dollars for customer capital investments in the test year to support the CX&O IT infrastructure. All IT-related capital costs discussed herein are in the IT budget and discussed by Company witness Stacy H. Baker.

Q. How is the remainder of your testimony organized?

A. My testimony is organized as follows:

I. Customer Experience and Operations

A. Customer Interactions

B. Billing and Payment

II. [redacted]

I. Customer Experience and Operations

Q. Please describe CX&O.

A. The activities of the CX&O organization strive to optimize the positive experience natural gas customers have when interacting with the Company. It has two major segments—Customer Interactions and Billing & Payment. Customer Interactions ensures that customers are equipped to connect with the Company in their preferred channel (phone, Interactive Voice Response ("IVR"), website, mobile app, or digital correspondence—such as text messages). Billing & Payment provides customers with accurate, punctual energy bills and consistent payment processes, and arranges personalized payment plans or settings (e.g., inability to pay arrangements, pay by phone/website, payment alerts, choose your own bill due date) for individual customers.

These two core strategies are fundamental to accomplishing the Company's customer experience goals. The Company relies on its array of customer experience offerings to ensure that customers are satisfied when interacting with Consumers Energy and are, therefore, positively inclined to enroll in its clean energy programs. The Company recognizes the energy industry is increasingly expected and committed to pursuing clean energy and believes that customer engagement and participation is critical to realizing this future.

Q. Is the Company's IT witness sponsoring any Customer projects?

A. Yes. Company witness Baker is sponsoring test year funding for three Customer-related technology projects totaling $1,292,439 in capital expenditures and $297,697 in O&M expenses. Please see Ms. Baker's testimony for additional information.

The IT Department is a critical partner in CX&O's plans and initiatives - relying on the expertise provided by IT to help develop and implement necessary digital solutions as identified in CX&O. IT maintains the Company's technology systems, ensuring they operate efficiently, reliably, and free from cybersecurity risks. IT also supports analytic platforms and solutions that provide deeper insight into customer needs and enables CX&O to establish appropriate targets for metrics, products, and customer programs, which are necessary to allow CX&O to select the most cost-effective and beneficial solutions for customers. Together, these departments ensure customers receive secure, reliable, and positive experiences across all channels of interaction with the Company. Continued investment in technology requires additional ongoing funding to initiate, support and maintain these platforms. Support for the CX&O business technology drivers is documented in the IT Digital Three-Year Plan, which is included as Exhibit A-17 (SHB-1). Cross-references to CX&O projects are noted below.

PROJECT	**CAPITAL**	**O&M**	**SQM-Testimony Reference**
Customer Order Service Tracker	$856,507	$178,155	DCO – page 15
Customer Work Request Web Portal	$435,932	$119,542	DCO – page 16
Total	**$1,292,439**	**$297,697**	

A. <u>Customer Interactions</u>

Q. Please provide an overview of Customer Interactions.

A. Customer Interactions is responsible for the execution and ownership of the various channels of customer interactions as identified above. This work includes the following areas of focus: Digital Customer Operations ("DCO"), Customer Contact Center, Business Customer Care ("BCC"), Credit and Assistance, and Analytics & Outreach. All five are aligned to the larger department goals of: (i) providing customers the opportunity to serve in their channel of choice; (ii) continuously improving the customer experience to allow customers to choose new programs and products to meet their energy needs; and (iii) allowing the Company to achieve its clean energy goals. To effectively perform in these areas, the Company is projecting $24.1 million of O&M expenses for the test year ending September 30, 2025, as shown on Exhibit A-91 (SQM-2).

1. Digital Customer Operations

Q. Please provide an overview of DCO.

A. DCO is responsible for the operation and continuous improvement of the Company's customer-facing digital applications, including the website and mobile application. The DCO team collects over 3,900 points of customer survey feedback every month, which drive the team's priorities in four simultaneous work cycles: (1) small, agile digital changes using available tools; (2) managing the design, development, and launch of monthly releases to add new features or modify user flows; (3) leading major technology projects that add new or modify existing functionality to better serve customers; and (4) executing the implementation of programs online to help accrue energy savings and clean energy opportunities for customers.

To continue this work, the Company is projecting $2.2 million of O&M expenses for the test year ending September 2025. As shown on Exhibit A-91 (SQM-2), this represents a decrease in O&M expenses of $1.5 million from the $3.7 million expended in 2022. Lower contractor costs account for the majority of this decrease.

Q. What types of transactions do customers complete online?

A. The most common reasons customers use the Company's website and mobile app are to check the billing status of their account (13.7 million views in 2022), make payments (14.2 million views in 2022), report an outage, or view the status of an outage (4.1 million outage page views in 2022), check energy usage information (1.2 million page views in 2022), and investigate additional service information—such as auto-pay, eBill enrollment, budget billing, and information on products and services. The Consumers Energy website also serves as the principal vehicle to enable customers to sign up for clean energy program rebates, enroll in energy saving programs, and save money with energy-efficient products.

Q. Please explain why the Company is continuing to invest in multiple digital methods to allow customers to complete transactions or find information in their channel of choice.

A. Customer needs vary widely, whether they are interested in reducing their energy use for environmental reasons, having their billing questions answered, or setting up the right day and time for their move-in. Continued investments are needed to keep pace with changes in customer habits and expectations as use continues trending toward more integrated and sophisticated digital services, as well as ensuring channel parity so that customers can complete all transactions in all channels.

Additionally, expanding the Company's digital channel enables customers to complete a variety of activities on a smartphone or computer at a time that may be more convenient than the limited call center service hours, shifting costs to the more cost-effective channel. Customers paid $2.4 million of bills through the web and $1.4 million via the mobile app daily. Both channels are on track to see $1.4 billion in payments yearly. Online transactions cost approximately $0.11 versus $9.22 per live agent call (utilizing internal contact center resources), making this a cost-effective alternative to expanding the call center service hours. The Company's digital channels are critical systems requiring proper levels of support to ensure they function when and how customers need them.

It is important to note that—like most peer institutions for which this has become the customer expectation - the Company continues to support several channels in response to customer needs and choices for communicating and completing transactions to meet customers where they are. The Company's IVR System currently co-exists in the digital platform space with the website/mobile website and the mobile app. Similarly, the Company maintains call centers and direct payment offices for customers who prefer to communicate or pay face-to-face. Many of these channels are maintained in service of the wide variety of customer needs given generational and socio-economic factors.

Q. Please describe the DCO capital costs included in the historical and bridge period.

A. The capital dollars identified for the bridge period are to support the DCO's data collection automation efforts. It will enable automated data analysis, metric generation, and operational tracking activities used to measure, benchmark, and assess the customer experience, which have up to now been manual. Additionally, automating new data processing from new sources helps avoid the costs of the 2-3 new full-time employees that would otherwise be required to complete the manual processes, and avoid the errors introduced by manual processing.

As the Company continually seeks to further its ability to understand customer demands and more efficiently resolve issues, these efforts require a rich data set that can be utilized to ensure customer offerings effectively and efficiently align to customer needs. The existing customer research system is designed to support these efforts; however, improvements can be made by better utilizing data to supporting new, more targeted, and more cost-effective customer offerings. This continued investment will automate further data collection including vendor and internal systems information, reformat it to conform to data standards, and incorporate it to the existing data repository.

This ensures the customer data available to internal business partners is centralized, streamlined, and visualized, reducing defects and rework, and increasing their ability to make the kind of connections that lower costs (e.g. reducing calls to the Contact Center) and reduce customer pain points (e.g. website speed during an outage) when interacting with the Company. Continuing to refine and add data sources will improve the ability of Customer Experience teams to assess customer sentiment, identifying the best course of action for addressing customer feedback and improving the experience overall.

Completing this automation and integration activity further supports the Company's ability to efficiently identify the right opportunities for customers who may require assistance, such as the Company's low-income demographic. With the robust data set, we can connect with the customer and target the right plan through the preferred communication channel.

Q. Is the CX&O Department proposing test year IT costs related to DCO projects?

A. Yes. Company witness Baker is sponsoring test year capital IT costs for two DCO projects: (i) $1,292,439 in capital and $297,697 in O&M in the test year for the Company's Customer Order Service Tracker and Customer Work Request Web Portal. Please see

Ms. Baker's testimony for additional information. The customer benefit of each project is discussed below.

CUSTOMER WORK REQUEST PORTAL

Q. Please detail the Customer Work Request Portal.

A. The Customer Work Request Web Portal project provides a comprehensive web interface which will allow customers to originate and view the status of new business service and service alteration requests and will provide the ability to obtain information about work orders and status updates at any time of day without having to contact a customer service representative. This project was developed in response to direct feedback from customers collected through Customer Experience data which indicated low scores in the 'Keeping You Updated' and 'Accommodating Your Schedule' categories due to the customer's inability to obtain timely work order status updates.

Q. Is this service already available on any of the Company's other digital channels?

A. No. For most types of customer-initiated work, the customer must contact the Energy Request Center via phone during normal business hours to schedule or reschedule work or to receive status updates. For certain requests (mainly new builds), the Company's website does offer limited self-service options for work order status updates—primarily for the Customer Energy Management ("CEM") team which does not target residential customers.

Q. What are the other benefits this project provides?

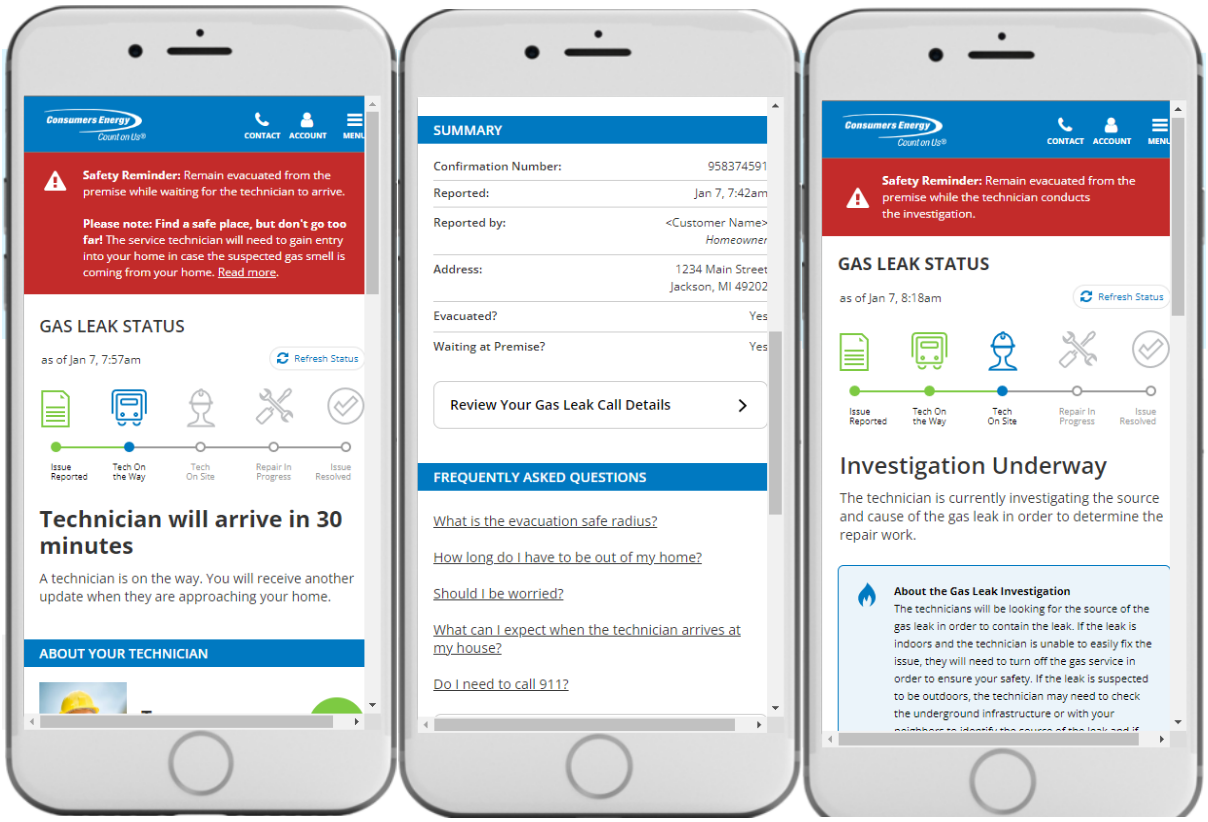
A. This project provides value for the Company and its customers by allowing customers and builders to start and submit new service requests from their web browser, use the submitted information to complete internal forms, pay service invoices, and display status updates for service requests and property restoration items. Today, these actions all must be initiated by the customer through the call center, necessitating customers' manual tracking of various notification numbers during the process. Additionally, today, new service invoices are generated manually and sent by email or postal mail making them difficult to keep track of, resulting in delayed or unpaid invoices.

CUSTOMER ORDER SERVICE TRACKER

Q. Please detail the Customer Order Service Tracker.

A. The Customer Order Service Tracker will implement a service order status tracker to provide both transparency to customers and oversight to internal teams supporting utility service orders across Company service areas. The tracker will provide timely and accurate service order updates, creating a more robust customer experience for tracking service order status and crew location updates, as well as an interactive digital channel for use by dispatch, scheduling, and field crews.

Helping the customer to understand where their request is in the process reduces frustration by providing a clear view into their order. This project seeks to offer a simple, informative option which the customer can easily access and check. The images below are mock-ups of the potential user experience flow, designed around a mobile device user in a gas leak emergency.



Q. Why is this project important in the customer space?

A. "Short cycle" orders include emergencies, forestry, meter services, and new construction, and they account for many of the incoming customer inquiries to the contact centers. Customers have very limited visibility into when Company-assigned crews will be on premise for this work because this information can only be obtained via phone calls to customer service representatives, resulting in approximately 346,000 annual contact center calls related to these short cycle requests. This leads to overall customer dissatisfaction due to lack of visibility into scheduled and ongoing short cycle work.

Current lack of visibility by dispatchers increases truck rolls because they are unaware of crew locations and routes which can cause crews to be assigned improperly. Enabling a digital channel for utility service order communication for both customers and dispatchers will improve customer experience and reduce the waste of repetitive crew dispatching.

Q. Are there additional benefits to the Customer Order Service Tracker?

A. At its fundamental level, this project will provide transparency on the timing and location of the assigned crew completing utility short cycle service orders. As a result, use of the tracker will reduce calls from customers seeking clarification by scheduling and communicating arrival timeframes and providing notifications when crews are in-route; improve resource assignment, decreasing wasted truck rolls; and allow crews to connect with customers through digital channels.

HISTORICAL/BRIDGE YEAR IT PROJECTS

MIMO (Move-In, Move Out) EE

Q. Please provide additional information for the Move in Move Out ("MIMO") – Energy Efficiency ("EE") project.

A. The Company incurred additional costs for the implementation of the MIMO project, as detailed in Company witness Baker's testimony. MIMO offers a customer benefit via extending the Company's customer self-service functionality to customers seeking to transfer or enroll in EE programs during MIMO transactions. Customers can access a digital portal that allows them to transfer or sign up for new programs for which their account remains eligible after their move, select a rate and a bill due date that works best for them, and reschedule a move date if needed. Previously, customers were not able to independently enroll or retain enrollment in EE or demand response programs when moving. Rather, they needed to call the Contact Center, driving up call volume and potentially driving their customer experience down if the Contact Center hours are not convenient for them.

MOBILE APPLICATION

Q. Please describe customer interaction in the Company's Self-Service Mobile Application since its launch.

A. Since the December 2021 launch, there have been over 504,000 downloads of the Company's Self-Service Mobile application, and use of the app has continued to grow, with 1.5 million bill payments, 15,000 outages reported, 18,000 eBill enrollments, 56,000 notification alert signups, 31,200 auto pay enrollments, and 12,125 budget plan enrollments—a feature recently made available on the app. Since adoption, the mobile app has accounted for 18.5% of all customer interactions and ranks as the second (out of 10) most popular customer communication channel. This growth is evidence that customers are swiftly moving toward app utilization as one channel of choice.

Q. Please describe the customer benefits of the Mobile Application.

A. The Mobile App uses a completely separate logic from the legacy digital products to allow for intuitive, quick, and efficient transactions, including simple login, direct access, and faster speed, offering customers a streamlined experience that allows them to complete the most common interactions on their phone. The Mobile App does not include the entirety of the website's information, but neither does it have the website's structural complexity, making it faster and easier to use by putting the most requested, or used, items on another device that most customers have access to 24 hours a day. The Mobile Application can also load without the use of a web browser, making it accessible in situations where web access is not available (e.g. a web outage).

Additionally, having the Mobile App available during potential website downtime or outages provides a consistent and reliable bridge platform for routine customer transactions while events are underway. Customers would have the convenience and simplicity of completing routine transactions, such as bill payment, in the Mobile App in the event unforeseen issues arise.

Q. Why is the Company continuing to pursue further development of the Mobile Application?

A. As detailed above, the Mobile Application is proving to be a popular and useful channel of choice for customers. The Company seeks recovery of funding spent in response to the initial and subsequent launches of the Application, responding to customer feedback, implementing additional usability and reliability, and enhancing the overall customer experience. Please see additional discussion of the related work in Company witness Baker's testimony.

CUSTOMER SELF-SERVICE ONLINE WORK SCHEDULING

Q. Why is the Company continuing to invest in the online work scheduling platform?

A. The Company has incurred additional costs for the implementation of the Customer Self-Service Online Work Scheduling project, as detailed in Company witness Baker's testimony.

Continued investment in the Customer Self-Service Online Work Scheduling Tool helps the Company to maintain a reduced call volume and an increased customer experience for "new business" services and alterations. Customers who require scheduled utility work at their premises for new services are able to self-serve much of the information they wish to provide to or obtain from the Company. The Company has updated the online customer self-service portal to enable online submissions of new requests and forms, which avoids the need for customers to call for information such as scheduled time of work, phase of the process, identifying which forms are required, and status updates.

This project will help to increase the Company's efficiency by reducing the manual work needed to directly communicate with customers. Since the initial launch, the Company has seen a 60% reduction in calls regarding new business services. It is further expected that further updates will provide a technical and business process foundation for other similar initiatives in the future.

BUSINESS CUSTOMER INTERVAL WEB PORTAL

Q. Why is the Company continuing to invest in the Business Customer Interval Web Portal?

A. The Company has incurred additional costs for the implementation of the Business Customer Interval Web Portal project, as detailed in Company witness Baker's testimony. The Business Customer Interval Web Portal project developed an Interval Web Platform for Business Customers to provide insight into their energy usage.

The Energy Dashboard, launched in 2019, is the newer generation of the legacy Interval Web Portal, which was originally developed to provide customers a self-service option for understanding the details of their energy use, including the ability to download usage data. This type of insight tool is a common customer offering within the energy industry and elsewhere, allowing the Company to build trust and transparency with customers.

This project continues to provide value to both the Company and its business customers through increased customer engagement and satisfaction through self-service capability focused on energy use reduction, and reduced calls and contacts with the Company regarding energy usage and energy use reduction options.

CX&O IT ENHANCEMENTS[1]

Q. Please describe how CX&O IT enhancements are identified and implemented.

A. CX&O IT enhancements are technology improvements which benefit customers and are implemented in response to the launch of a channel, customer tool, project completion and/or direct customer feedback. Depending on the need identified, enhancement dollars could be utilized to support the enhancement of any customer supporting feature and/or capability, often as emerging requests. These items are small-scope items with a reduced budget and fewer resource requirements in comparison to larger capital investments. Having the flexibility to implement CX&O IT enhancements enables the Company to meet emerging needs without the longer lead time of rate case submissions.

Examples of enhancements include improving overall functionality of the channel or tool, analytics on platform usage, addressing issues identified internally or via customer feedback, adding relevant or customer-driven capability, and performance monitoring.

Q, How do CX&O IT enhancements benefit the Company's customers?

A. Enhancements assist the Company in providing a better, more optimized customer experience for customers through improved understanding of how they use the channels or tools, which features are important to their experience, and how the channels or tools are performing. Specific enhancements are discussed throughout my testimony in the corresponding business area and IT Company witness Baker's testimony.

[1] For 2021 and 2022 the actual project name was Enhancements-CX&O-Capital and starting in 2023 the project is named **Product Family Enhancements-Customer-Capital**.

2. Customer Contact Center

Q. Please provide an overview of the Customer Contact Center.

A. The Customer Contact Center is responsible for staffing and operating the Company's call centers, which serve all residential and small business customer calls. In 2023 year-to-date ("YTD"), call center representatives have answered 1.88 million customer calls. Likewise, the IVR system addressed 3.8 million calls YTD 2023.

To continue this work, the Company is projecting $14.7 million of O&M expenses for the test year ending September 2024. As shown on Exhibit A-91 (SQM-2), this represents an increase in O&M expenses of $1 million from the $13.7 million expended in 2022. Most of the increase is due to increases in labor costs.

3. Business Customer Care

Q. Please provide an overview of BCC.

A. BCC works directly with the Company's commercial and industrial ("C&I") customers, and includes the Business Center, which is responsible for assisting the Company's larger business customers with support such as phone agents and account management. The organization's main goal is to deliver an exceptional customer experience, while identifying opportunities that provide them with added energy value. Overall, BCC serves approximately 100,000 customers, equating to 200,000 contracts. This represents $2.7 billion to the Company's total annual revenue.

To continue the work in this area, the Company is projecting $1.6 million in O&M expenses for the test year ending September 2025. As shown on Exhibit A-91 (SQM-2), this represents a decrease in O&M expenses of $400,000 from the $2.0 million expended in 2022. Lower contractor costs accounts for most of this decrease. In addition, as shown on Exhibit A-12 (SQM-1), Schedule B-5.8, the Company had $469,668 of capital expenditures in the historical test year. These expenditures were used to develop the infrastructure necessary to compensate sales employees as they drive enrollment in Company programs such as EWR, DR, VGP and others.

4. Credit and Assistance

Q. Please provide an overview of Credit and Assistance.

A. Credit and Assistance consists of: (1) Theft Investigations, (2) Revenue Operations, and (3) Energy Assistance, which collectively manage the Company's collections cycle and support its most vulnerable customers by connecting them with Company-sponsored payment plans and public assistance funding to help customers pay their bills.

The Theft Investigation Team provides the critical service of identifying and ending energy theft in the Company's service territory – important both for maintaining the safety and integrity of the Company's system and minimizing all customers' costs. In 2022, the team identified 1,310 confirmed cases of theft and billed for $672,115.99 in unauthorized use and investigation costs – a decrease of 327 cases and an increase of about $86,000 billed over the previous year.

Revenue Operations addresses past due customer accounts or those involved in bankruptcy. Employees within this area manage the collections cycle, beginning with issuing a notice to customers and ending with visiting their premises to disconnect service. This group also manages contracts with outside collection agencies to recover payments from customers with outstanding balances. In 2022, the Company contracted with outside collection agencies for $2.1 million (covering recovery for both gas and electric accounts). Consequently, the agencies recovered $7.5 million of previously written-off customer balances, of which $2.4 million accounted for *gas-only* recoveries (33% of total). Recovery of these payments directly offsets the uncollectible expense discussed in the testimony of Company witness Matthew J. Foster.

The Energy Assistance team is responsible for administering the Company's Consumers Affordable Resource for Energy ("CARE") Program, which supports low-income customers who may be struggling to pay their monthly energy bills. By coordinating with other organizations in fiscal year 2022 this team obtained $10.28 million of assistance for its customers requested through the Michigan Energy Assistance Program ("MEAP") – which helps provide customers with either a one-time bill assistance payment or on-going support via enrollment into an Affordable Payment Plan. These plans offer customers reduced monthly bills and gradually pays down any arrears brought into the program. In addition to MEAP assistance, customers received $20.3 million in State Emergency Relief payments and $11.5 million in Home Heating Credit assistance.

To continue the work in this area, the Company is projecting $2.7 million in O&M expenses for the test year ending September 2025. As shown on Exhibit A-91 (SQM-2), page 3, this request represents an increase of about $100,000 in O&M expenses from the $2.5 million expended in 2022.

5. <u>Analytics and Outreach</u>

Q. Please provide an overview of the Analytics and Outreach area.

A. The Analytics and Outreach team provides a suite of functions which include customer research, data analytics, and customer outreach. Work performed by this team supports the entire CX&O organization and the Company in general.

By collecting and analyzing data from customers or syndicated and industry sources, the team can provide insights that allow the Company to improve overall customer experience, develop new service options, respond to regulatory reporting, and pursue more effective customer communications—communicating and engaging customers with the right offer, with the right message, and in the right channel.

The Company is projecting $3.0 million of O&M expenses for the test year ending September 2025, as shown on Exhibit A-91 (SQM-2). This represents a decrease of $60,000 from the $3.1 million expended in 2022. This decrease is attributed to the department's expenses now being carried by the teams who request their marketing and market research services (Demand Response, Energy Waste Reduction, etc.) and are reflected on those budgets.

B. Billing and Payment

Q. Please provide an overview of Billing and Payment.

A. Billing and Payment is responsible for leveraging customer feedback to ensure payment processes are consistent and simple, monthly energy bills are accurate and easy to comprehend, and customers receive their bills in a timely fashion. The work in this department is divided between Customer Billing and Customer Payment Programs. The Company is projecting $ 9.6 million of O&M expenses for the test year ending September 2025. As shown on Exhibit A-91 (SQM-2), this represents a decrease in O&M expenses of about $8.0 million from the $17.5 million expended in 2022. This decrease is mainly due to the Company's policy shift in assessing credit card fees.

1. <u>Customer Billing</u>

Q. Please provide an overview of Customer Billing.

A. Customer Billing manages the exceptions process, which is a quality control process designed to review unusual bills (both digital and paper) and bill for unique programs before they are sent to customers. This review may involve contacting customers to gather additional information or to inform them of a potential billing issue. Bills may be corrected through the billing adjustment process, or meters maybe reread as part of the validation process. Rigorous improvement efforts to ensure every customer bill is accurate results in the Customer Billing team continually optimizing its processes and technology to aid in the review of billing exceptions. Ensuring that customers receive the right bill every time is critical. To continue this work, the Company is projecting $8.2 million of O&M expenses for the test year ending September 2025. As shown on Exhibit A-91 (SQM-2), this represents a decrease of $200,000 from the $8.4 million expended in 2022.

Q. Please explain the costs within Customer Billing.

A. The cost for stationery, forms, and postage related to the Company's billing and dunning communication processes is included in Customer Billing. In 2022, the Company mailed nearly 21 million paper bills, and approximately 2.4 million dunning notices. As illustrated in Figure 1 below, the Company has incurred increased postage rates in recent years, and the increased costs of additional dunning notices being mailed.

Figure 1. Current and Projected Dunning and Postage Costs

To mitigate these cost increases, the Company has taken action to increase customer enrollment in electronic billing, or eBill. Consumers has successfully increased eBill participation from <27% in 2017 to 46% as of Q2 of 2023, which is 1st quartile performance.[2] This growth has offset postage costs by over $2.5 million annually by reducing the number of pieces mailed.

However, cost per piece of postage has steadily increased over the past three years (6% in 2022) and is expected to continue to increase due to US Postal Service postage increases, offsetting the savings realized from growing eBill enrollment. Without eBill enrollment increases in the cost for postage would cause cost for customer billing to steadily rise in total. In addition, as shown on Exhibit A-91 (SQM-1) the Company spent $85,753 during the projected bridge period on printers used for customer bills. Two of the

[2] 2022 YE FirstQuartile Consulting

Company's printer reached end of life during 2023 and it was necessary to replace them to continue to be able to bill customers.

2. Customer Payment Programs

Q. Please describe the CX&O Customer Payment Programs group.

A. Customer payments are among the most sensitive and frequent touchpoints the Company has with customers, with approximately 34 million payments made annually. The Company's Customer Payment Strategy focuses on removing payment difficulties, providing payment options that customers expect, and ensuring all customers have the same easy payment experience regardless of how they choose to pay their bill. This has resulted in a significant reduction of payment-related calls and complaints and improvement in customer experience. The Company continues to make it a priority to accommodate customer preferences with a variety of desirable options to meet current customer expectations and to maintain a single set of customer-friendly payment rules that apply across all payment options.

Q. Please describe the costs associated with the Customer Payment Programs.

A. The Company is projecting $1.3 million in 2025 test year O&M expenses shown on Exhibit A-91 (SQM-2). This represents a $7.7 million decrease from the $9.0 million expended in 2022.The decrease is mostly due to ending the socialization of credit card fees. Operating costs associated with customer payments continue to evolve with changes in customer behaviors and preferences.

Q. What are the anticipated payment processing fees costs for the test year?

A. Within the $1.3 million of Customer Payment Programs test year O&M, the Company is projecting $477,507 in payment processing fees O&M expenses for the test year.

Additional payment-related fees over the $477,507 above include bank lock box fees in the amount of $372,499 and approximately $473,662 in Direct Payment Office ("DPO")-related payment fees.

Q. What payment fees are included in the case?

A. Additional payment-related fees over the $1.3 million above include bank lock box fees in the amount of $356,474 and approximately $849,440 in DPO-related expenses.

Q. Are there additional changes to the way the Company collects payment processing fees?

A. The Company has implemented a policy change which asses customers a payment card service fee when paying by debit or credit card.

Q. Are the payment fees recovered from all customers?

A. The various forms of payment the Company accepts include Electronic – Web Banking, Digital – ACH (CE.com, Mobile App, IVR, Text), Electronic – Business eLockbox, C&I Business – Electronic Data Exchange (CTX), Mail (checks), Electronic Business Portal (BillTrust), Digital Card (CE.com, Mobile App, IVR, Text), In Person – Paystations (Authorized Pay Agent), CE Payment Office – Check, CE Payment Office – Cash, and CE Payment Office – Card. All are recovered from all customers except for Authorized Pay Agents and Card Processing. Outside of Direct Payment Offices, these two categories represent the highest per transaction costs for payment processing.

Q. Does the Company anticipate any revenues generated by assessing payment card service fees to customers continuing to pay with a credit/debit card?

A. No, the Company does not anticipate or forecast any revenue being generated from the card payment processing fees.

Q. Please provide an overview of DPOs.

A. Consumers Energy has eight DPOs around the state of Michigan, all located within existing Company facilities, making them a cost-effective option for customers to pay their bills in person. These offices serve some of the Company's most vulnerable customers, such as seniors and low-income customers, providing them with a community resource that can connect them with billing options and assistance opportunities.

Q. Does the Company offer other in-person payment options in addition to the remaining DPOs?

A. Yes. The Company has maintained its relationship with an authorized pay agent, that accepts payments at stations such as Wal-Mart, Kroger, and other associated store fronts. These pay stations serve as de facto DPOs. This provides customers with the continuity and convenience of being able to pay their bill without having to locate a DPO. Customers are charged a fee to pay their bill in these locations, which covers the costs of the processing fee the Company is charged to have this option.

Q. Does the Company itself collect the payment fee?

A. It does not. The authorized pay agent implements and collects the fee from the customer utilizing their services.

Q. Will the fee remain $1.75?

A. No. Going forward the fee will be $1.50 per the agreement between the vendor and the Company.

II. [redacted]

[redacted]

[redacted]

[redacted]

[redacted]

Q. Does this conclude your direct testimony?

A. Yes.

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the application of	)	
CONSUMERS ENERGY COMPANY	)	
for authority to increase its rates for the	)	Case No. U-21490
distribution of natural gas and for other relief.	)	
	)	

DIRECT TESTIMONY

OF

KRISTINE A. PASCARELLO

ON BEHALF OF

CONSUMERS ENERGY COMPANY

December 2023

Q. Please state your name and business address.

A. My name is Kristine A. Pascarello, 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. I am a Senior Strategy Manager in the Gas Strategy department within Gas Engineering and Supply. I have held this position since July 2019.

Q. What are your responsibilities as Senior Strategy Manager?

A. I perform the asset lifecycle oversight, guidance, and leadership of the Natural Gas Delivery Plan ("NGDP") development, implementation, recovery, and verification of results focused on the Distribution assets.

Q. What other relevant experience do you have?

A. I have worked for Consumers Energy for 24 years. I have been a Senior Strategy Manager in Gas Engineering and Supply since 2019. I have also served the Company as a Project Manager, Deployment Lead, Senior Engineer Lead, and Engineer. Prior to becoming a Senior Strategy Manager, I spent 10 years on the Smart Energy Advanced Metering Infrastructure ("AMI") and Gas Automated Meter Reading ("AMR") project teams where I was responsible for leading field implementation activities required to install electric smart meters and gas communication modules. This involved business process redesign and system requirements definition, working with a wide variety of stakeholders including customers, municipalities, and various Company departments such as Field Operations, Supply Chain, Customer Contact Center, Rates, Damage Claims, and Security, and successfully implementing new technology while delivering a high-quality customer experience. I was also the contract administrator and Company supervisor for the meter installation vendor. Before joining the AMI/AMR projects, I was in the Gas Engineering department. I was the Gas Measurement Lead for 2.5 years, the Electrical, Instrumentation, and Controls ("EI&C") Lead for 5 years, and a General/Senior Engineer for 2.5 years. As the Gas Measurement Lead, I led the Measurement Center of Excellence, was responsible for Lost and Unaccounted for Gas ("LAUF") projects including the development of standardized gas measurement processes, and the monitoring of LAUF, including implementation of Flow-Cal gas measurement software. During my 7.5 years as the EI&C Lead/Engineer, I was responsible for project management and electrical design of the Company's natural gas facilities, including managing the Gas Transmission and Distribution Supervisory Control and Data Acquisition ("SCADA") system designs and installations. Prior to joining Consumers Energy, I worked as an Electrical Engineer at Dart Container for four years where I was responsible for machine control design, including PLC programming and variable frequency drives. I started my career as an Electrical Engineer at Florida United Engineers, where I was a contract electrical engineer for Florida Power & Light specializing in generation power distribution processes and power plant control/alarm designs for seven years. I have a total of 35 years of experience, with 31 years in the utility industry.

Q. Are you a member of any professional societies or trade associations?

A. Yes. I am currently a member of the Engineering Society of Detroit. I am also a certified Project Manager through the Project Management Institute ("PMI"). I have represented the Company at the American Gas Association ("AGA") where I served as a Distribution

Measurement Committee ("DMC") officer, chaired the AMI/AMR subcommittee, and delivered presentations during conferences. I have also served on the American National Standards Institute ("ANSI") B109 working committee.

Q. What is your formal educational experience?

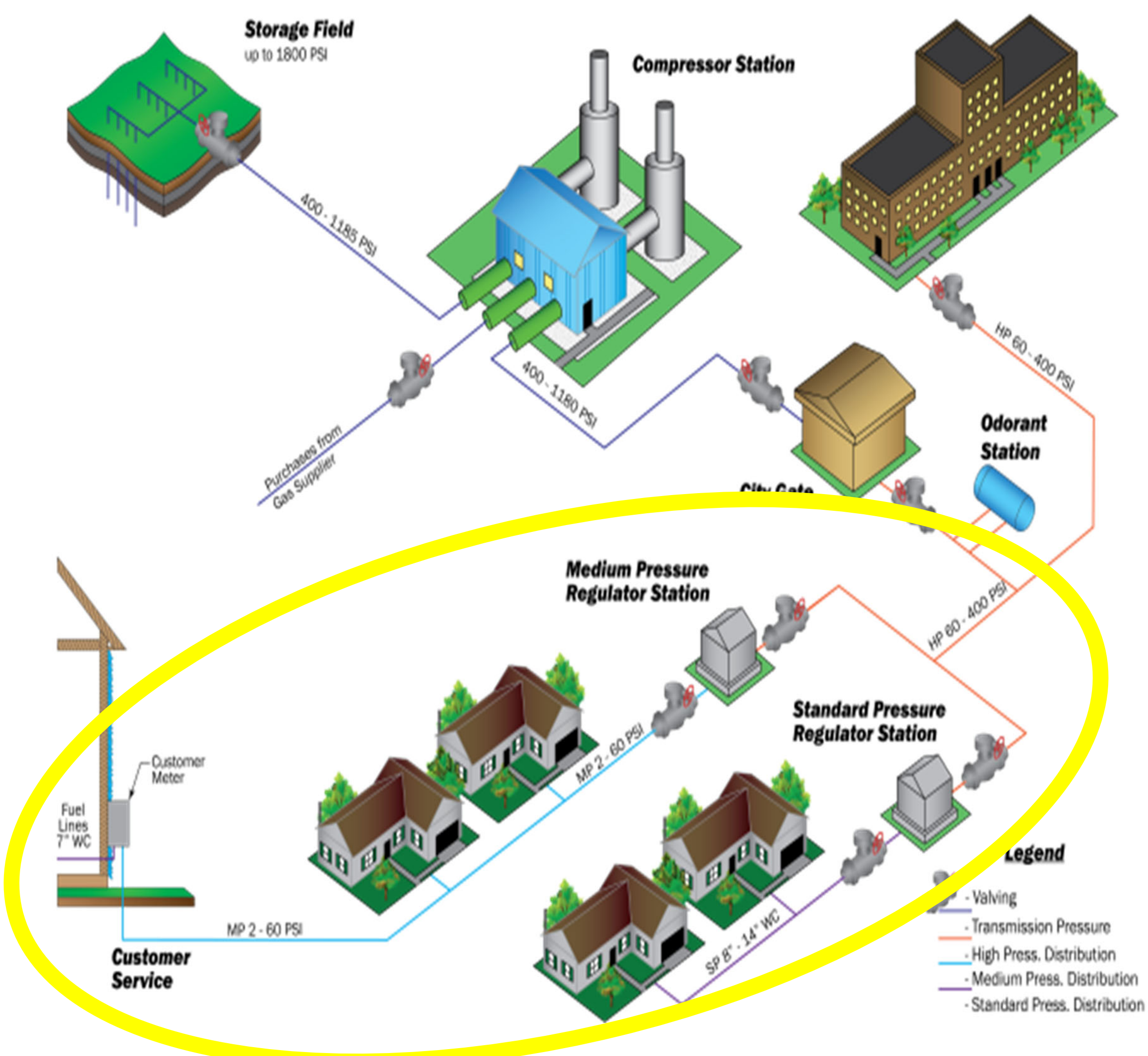
A. I graduated from Lake Superior State University with a Bachelor of Science degree in Electrical Engineering Technology. I graduated with an Associate of Science degree in Electronics from Lansing Community College. I also hold Master and Associate Certificates in Project Management from George Washington University, and Gas Measurement Fundamentals Certification from the Gas Certification Institute. In addition, I passed the Fundamentals of Engineering exam in 2004.

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

A. Yes, I testified in Case Nos. U-20893, U-21148, and U-21308.

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 Gas Engineering and Supply ("GE&S") Operating and Maintenance ("O&M") expenses, and certain gas distribution capital investments that are intended to keep the system safe and reliable while providing affordable and clean energy to customers. This includes engineering, strategy, and gas supply for this system as well as gas control of the transmission system. 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, a portion of which is monitored by Gas Control. In the diagram below, these assets are inside the yellow highlighted section.



These expenditures are primarily related to the operation of the Company's gas mains, services, and meters downstream of the city gates. These investments will ensure the continued safe delivery of gas through this system to customers.

I have divided my direct testimony into two parts: (i) a description of the O&M expenses related to the Company's GE&S department; and (ii) a description of the Company's gas distribution capital expenditures that I am sponsoring for 2022, 2023, the nine months ending September 30, 2024, and for the projected test year 12 months ending September 30, 2025. My direct testimony covers the capital cost for the Material Condition and Gas Operations Other programs. The remaining capital programs for Distribution are sponsored by Company witness Lincoln D. Warriner.

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 GE&S department is responsible for the engineering, design, strategy, project management, construction support, and gas supply and control associated with execution of the NGDP. The distribution capital programs represented in my direct testimony work toward achieving the NGDP's objectives of eliminating vintage materials and leaks, as well as providing safe and reliable service.

Q. Are you sponsoring any exhibits?

A. Yes. I am sponsoring the following exhibits:

Exhibit A-94 (KAP-1)		Summary of Actual & Projected O&M Expenses, Gas Engineering and Supply;
Exhibit A-95 (KAP-2)		Detailed Summary of Actual & Projected O&M Expenses, Gas Engineering and Supply;
Exhibit A-12 (KAP-3)	Schedule B-5.9	Projected Capital Expenditures, Distribution Plant – Material Condition and Gas Operations Other, Summary of Actual & Projected Gas and Common Capital Expenditures;
Exhibit A-96 (KAP-4)		Actual & Projected Gas Capital Expenditures - Material Condition Program;

Exhibit A-97 (KAP-5)	Actual & Projected Gas & Common Capital Expenditures - Gas Operations Other Program;
Exhibit A-98 (KAP-6)	2022 Gas Enhanced Infrastructure Replacement (“EIRP”) Annual Performance Report Attachment 4;
Exhibit A-99 (KAP-7)	Detailed Summary of Actual and Projected Capital Expenses – Enhanced Infrastructure Replacement Program;
Exhibit A-100 (KAP-8)	Projected Capital Expenditures - Distribution Plant - Material Condition and Gas Operations Other, Summary of Actual & Projected Gas and Common Capital Expenditures.

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

A. Yes.

Q. Please summarize your direct testimony.

A. First, I will address the reasonable and necessary O&M expenses for the Company’s GE&S department, which are described on Exhibit A-94 (KAP-1). The total O&M expenses were $13,930,000 in 2022; and are projected to be $17,883,000 for 2023; $22,465,000 for 2024; and $22,036,000 for the test year 12 months ending September 30, 2025, as set forth on this exhibit on line 5, columns (b) through (e).

Second, my direct testimony also represents certain Gas Distribution capital investments through September 30, 2025, which are described on Exhibit A-12 (KAP-3), Schedule B-5.9. The total Gas Distribution capital expenditures represented by this direct testimony were $347,150,000 in 2022 and are projected to be $291,668,000 for 2023; $223,675,000 for the nine months ending September 30, 2024; and $350,845,000 for the projected test year 12 months ending September 30, 2025; as set forth on this exhibit on line 3, columns (b), (c), (d), and (f), respectively.

Q. How has the Company projected its O&M expenses for 2023, 2024, and the test year 12 months ending September 30, 2025?

A. The Company has projected its O&M expenses for 2023, 2024, and the test year 12 months ending September 30, 2025, to the level that is reasonable and necessary to meet customer service and safety requirements. This projection is based upon multiple factors, including annual merit increases for the GE&S department, a 2023 Company reorganization that increased the personnel level from the 2022 historic period, and projected O&M expenses for individual programs necessary to ensure customer safety, meet regulatory requirements, and provide reliable service to customers. First, for the O&M expenses representing the 2022 GE&S employee salaries and expenses, the Company projected the amount of the O&M expenses by applying either an inflation rate or a merit increase rate, or both to historical 2022 O&M expense. The Damage Claims/Prevention, Enterprise Corrective Action Program ("ECAP"), and Advanced Methane Detection personnel were added to GE&S in 2023 as part of a Company reorganization. The Company projected the O&M expenses for these departments in the same manner as 2022 GE&S employees. The 2022 historical O&M information for these departments is included in Company witness James P. Pnacek's Exhibit A-104 (JPP-4) page 3, line 1, Compliance and Controls. The test year projections are included in Exhibit A-95 (KAP-2). The test year salaries and expenses were projected to account for staffing levels resulting from the Company reorganization and are described within each respective section later in this direct testimony. Lastly, the projection methodologies vary among the different O&M programs and are described within each respective section later in this direct testimony.

Q. Please describe the methodology 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 programs, using historical costs and adjusting for market conditions impacting areas such as materials and outside services, necessary to ensure customer safety, meet regulatory requirements, and provide reliable service to customers. The projection methodology is based on the monthly cash flow average percentage, using the three-year historical period of 2020 through 2022.

<u>GAS ENGINEERING AND SUPPLY DEPARTMENTS O&M EXPENSES</u>

Q. Please explain the source of the 2022 actual O&M expenses for the GE&S department expenses shown on Exhibit A-94 (KAP-1), line 5.

A. The 2022 actual O&M expense amount of $13,930,000 for the GE&S department was taken from Consumers Energy's internal reporting records. This total amount includes both labor and non-labor O&M expenses for this department, and the labor, material, contractor, non-labor overheads, and other non-labor expenses are detailed on Exhibit A-95 (KAP-2), pages 1 through 4. The 2022 level of expense allowed the Company to provide the engineering and support needed to serve 1.8 million natural gas customers and complete reasonable and necessary investments in 2022. The projected expenses for 2023 are $17,883,000, for 2024 are $22,465,000, and for the test year 12 months ending September 30, 2025, are $22,036,000 as shown on Exhibit A-94 (KAP-1), line 5, columns (c), (d), and (e), respectively. The calculation of expenses in the test year of this case is further described below.

Q. Please explain the derivation of the GE&S department O&M expenses for the test year as shown on Exhibit A-94 (KAP-1), line 5, column (e).

A. First, the Company has projected expenses for engineering and supply personnel, including departmental changes resulting from Company reorganizations, to implement the investment in the gas system replacement as described in the NGDP. The departmental reorganizations included the following changes:

- The Customer Energy Management ("CEM") department moving from GE&S to Operations Performance. The 2016 through 2021 historical expenses for this department are included in Exhibit A-95 (KAP-2), page 10, line 14. The 2022 historic expenses, 2023, 2024, and the test year ending September 30, 2025, projected expenses are included in the Operations Performance department shown on Exhibit A-101 (JPP-1), page 1, line 4 sponsored by Company witness Pnacek.
- The transition of the Operations Compliance and Controls ("OC&C") department into other departments enabling these groups to integrate to the areas they support and to optimize efficiencies. The OC&C departments that transitioned to GE&S include the Advanced Methane Detection ("AMD") team, moving to the Regulatory and Compliance department, and the addition of the Damage Prevention/Claims and ECAP departments.

The OC&C reorganization added 57 to the 2022 GE&S staffing level, with 2023 then being reduced by vacated positions that are not projected to be refilled. The result is an overall reduction in GE&S staffing for 2023, 2024, and the test year ending September 30, 2025.

The total staffing level represented by this direct testimony for year-end 2022, and the projected year-end for years 2023, 2024, and 2025, are 567, 582, 587, and 587 respectively. Each affected department within GE&S analyzed the work activities and factored in productivity improvements to project the number of employees necessary to complete the work for the NGDP. This staff will be responsible for engineering planning, engineering design, permitting, and construction support for the gas system enhancements as well as gas compliance, geospatial management, strategy, damage claims/prevention, enterprise corrective action, gas control, supply, transport and customer choice, and system and operations planning.

Secondly, the Company has projected O&M expenses for the Storage Integrity Management Program ("SIMP"), the AMD Program, and the Geospatial Inventory and Modeling Program. The details of these programs and the associated O&M expenses are described later in this testimony.

The expense levels for the GE&S department represented in Exhibit A-94 (KAP-1) were derived by starting with the 2022 level of actual O&M expenses. These expenses are further detailed on Exhibit A-95 (KAP-2) pages 1 through 4. As shown on Exhibit A-95 (KAP-2), pages 5 through 7, the 2022 actual O&M expenses were $13,930,000 as shown on line 15, column (b). The test year expenses were then derived by applying the respective inflation percentages to the 2022 actual expenses for each respective time period. The annual inflation rates used are shown on Exhibit A-95 (KAP-2) page 7, line 16. Added to this total is the O&M projected expenses for the OC&C departments, using the same process and inflation factors described above and is shown on Exhibit A-95 (KAP-2) pages 6 and 7, lines 9, 12, and 13. The remaining increase in the projected O&M

expenses is due to increased expenses in the O&M programs listed above and is shown on Exhibit A-95 (KAP-2) page 6, lines 7, 9, and 11. The resulting projected costs for the 12 months ending September 30, 2025, are $22,036,000, and can be found on Exhibit A-95 (KAP-2), page 7, line 15, column (j). These expense levels for the GE&S department will allow the Company to meet customer service, deliverability, and safety requirements in the test year.

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

A. No, there are not. The direct testimony and exhibits of Company witness Amy M. Conrad contain the EICP O&M expense dollars.

Q. Please briefly describe each of the departments within GE&S, as listed on Exhibit A-95 (KAP-2).

A. Gas Engineering and Supply is described in four major departments:

- Gas Project Management and Quality Lean;
- Gas Asset Management – Consists of Gas Engineering - Distribution, Gas Engineering – Transmission, Gas Engineering Asset Planning, System Integrity, which includes SIMP, and Gas Compression Engineering;
- Gas Engineering Support – Consists of Gas Strategy, Gas Regulatory and Compliance, which includes the AMD Program, Geospatial Management and Data Quality, which includes the Geospatial Inventory and Modeling Program, Damage Claims/Prevention, and ECAP; and
- Gas Management Services.

Q. Please briefly describe pages 5 through 7 of Exhibit A-95 (KAP-2).

A. Pages 5 through 7 of Exhibit A-95 (KAP-2) present the amounts of the O&M expenses by applying either an inflation rate or a merit increase rate, or both to historical O&M expense. Column (b) shows the historical O&M expense. Column (c) shows the historical amount to which an inflation rate or merit increase rate is applied. Columns (e) and (g) show the amounts when an inflation rate or merit increase rate is applied for the 2023 and 2024 bridge periods, respectively. Columns (d), (f), and (h) show the merit and inflation amounts for each respective period. Amounts that were projected using other methods are included in column (i). Column (j) is the projected test year O&M and is the sum of columns (b), (d), (f), (h), and (i); column (j) is aligned with the Company's projected expenses for each sub-program for the test year, as shown in Exhibit A-95 (KAP-2), pages 1 through 4. Therefore, column (i) represents the increase (or decrease) in O&M expenses that is not due to inflation; in other words, this represents where O&M expenses are changing due to some other factor than inflation. Where column (i) indicates a significant difference between O&M expense increases that are due to inflation as opposed to some other factor, it will be addressed as I describe each department's expenses.

Q. Please describe the activities of the Gas Project Management and Quality Lean departments.

A. Gas Project Management provides project oversight and management for certain programs and projects that are required by the business or directly for a customer. These programs and projects are usually large or complex in nature and require project management methodology to ensure predictable results. The Gas Project Management team includes Company-employed and contract project managers who oversee projects and ensure that each project meets the intended scope, schedule, and cost projection.

The Quality Lean department assists in evaluating current enterprise-wide process improvements through Value Stream Assessments. After which, continuous improvement opportunities are identified and solved using the CE Way Lean Toolbox. Continuous improvement opportunities increase the value proposition for the co-worker and for customers.

The projected O&M expenses for the Gas Project Management and Quality Lean department for the 12 months ending September 30, 2025, is $1,635,000, as shown on Exhibit A-95 (KAP-2), page 1, line 1, and consists of the O&M portion of the salaries and expenses for project managers, performance managers, and their Company-employed and contracted support staff. The support staff for Gas Project Management ensures project schedules are produced, tracks project expenses, provides construction oversight and inspection, and ensures appropriate resources are available for the project. The Quality Lean support staff ensures quality management implementation in planning and execution of work.

Q. What operating sections are included in the Gas Asset Management department?

A. The Gas Asset Management department consists of all engineering and technical support for planning, designing, performing risk assessment, and construction support of the transmission mainlines, distribution mains, storage laterals and wells, service lines, meter installations, regulating stations, compressor stations, and other infrastructure involved in delivering natural gas to customers safely and reliably. Gas Asset Management consists of five sub departments that I will describe more fully below. They are:

- Gas Engineering – Distribution;
- Gas Engineering – Transmission;
- Gas Engineering Asset Planning;
- System Integrity; and
- Gas Compression Engineering.

The employees within Gas Asset Management provide gas engineering and asset planning for the compression, storage, transmission, and distribution pipelines, large metering, regulation, and measurement assets, along with directing compliance-related programs such as System Integrity, supporting the Company objectives of supplying safe, reliable, affordable, and clean energy to customers. Gas Asset Management provides necessary expertise and services in the areas of distribution and transmission system risk, engineering, and technical design standards, performs system load studies, and initiates augmentation projects to ensure the capacity of the gas distribution system can meet projected customer demands. Additionally, this area provides the technical expertise and coordination for public infrastructure projects initiated by third parties, such as cities, Michigan Department of Transportation ("DOT"), and large new industrial customers. Gas Asset Management includes System Integrity, which implements the SIMP, and is responsible for the storage wells and pipelines within the storage fields. Gas Compression Engineering is also a part of Gas Asset Management and is responsible for engineering of the Company's compressor station assets. The salaries and expenses of all the Gas Asset Management teams described above and the expenses for the SIMP for the 12 months ending September 30, 2025, are represented on Exhibit A-95 (KAP-2), pages 1 and 2, lines 2 through 7.

Q. Please describe the activities of the Gas Engineering - Distribution department.

A. The Gas Engineering - Distribution department consists of four sections. The Distribution Pipeline Engineering team is responsible for the design of all new and replacement gas mains across the Company's distribution system. In 2023, the Company also consolidated designs of customer-requested service work into this team as well, meaning that all main and service design performed by the Company is now done within the Distribution Pipeline Engineering team. The Gas System Engineering team is responsible for emergent engineering projects and operational support across the Company's distribution system. The Design Quality and Contracts team is responsible for ensuring consistent and high-quality designs through review and coaching for the design technicians in Distribution Pipeline Engineering. The Design Quality and Contracts team also works on process development and technology improvement projects to make design teams more efficient. Additionally, this team owns the contracts for any outside engineering services needed to support the Distribution Engineering team. The Distribution Engineering Services team is responsible for field support and field GPS data collection on installed gas distribution assets. The projected O&M expenses for the Gas Engineering – Distribution department for the 12 months ending September 30, 2025, is $738,000, as shown on Exhibit A-95 (KAP-2), page 1, line 2, and consists of the O&M portion of the salaries and expenses for engineers, designers, analysts, and other support staff needed to meet the design and planning needs of the NGDP.

Q. Please describe the activities of the Gas Engineering - Transmission department.

A. The Gas Engineering - Transmission department contains two sections. First, the Transmission Pipeline Engineering section is responsible for the engineering and design of the Company's transmission and storage pipeline facilities and supports the following transmission pipeline capital programs: Asset Relocation-Transmission, Deliverability Base Pipeline, Maximum Allowable Operating Pressure ("MAOP") Pipeline, MAOP Transmission (O&M), and Transmission Enhancements for Deliverability & Integrity ("TED-I"). The Transmission Engineering employees have responsibility for improving the pipeline system and ensuring compliance with applicable regulations. The second section is the Metering, Regulation & Controls Engineering ("MR&C") team. MR&C is responsible for the engineering, design, and technical support of the Company's regulator stations, city gates, odorizers, and large customer meters through the following capital programs: Transmission City Gates, Distribution Regulator Stations, MAOP Metering & Regulation, and Deliverability Based Field Measurement. My testimony covers the labor and expense costs for staffing of the Gas Engineering - Transmission department. The capital programs described above are sponsored by Company witness Michael P. Griffin. The projected O&M expenses for the Gas Engineering – Transmission department for the 12 months ending September 30, 2025, is $1,432,000, as shown on Exhibit A-95 (KAP-2), page 1, line 3, and consists of the O&M portion of the salaries and expenses for engineers, designers, analysts, and other support staff needed to meet the design and planning needs of the NGDP and the O&M expense for the purchase of odorant.

Q. Please describe the activities of the Gas Engineering Asset Planning department.

A. Gas Engineering Asset Planning is responsible for the development of long-range engineering programs, such as Gas Enhanced Infrastructure Replacement Program ("EIRP") and Vintage Service Replacement ("VSR"), as well as coordination of annual projects across engineering organizations. Gas Engineering Asset Planning partners with Gas Operations and Gas Distribution Engineering to develop long-range projects. In addition, Gas Engineering Asset Planning partners with Gas Strategy to develop the NGDP. Gas Engineering Asset Planning is responsible for securing Right-of-Way permits for current Gas Distribution construction projects and works to negotiate favorable permitting requirements for future work. Gas Engineering Asset Planning is responsible for aligning project schedules and outages across asset classes, such as transmission and distribution, to create efficiencies and reduce the impact on customers. Gas Engineering Asset Planning is also responsible for the engineering and coordination of the Asset Relocation – Civic Program as well as, Distribution – Augment, and Distribution – Compliance Base. Finally, Gas Engineering Asset Planning is involved with research of new technologies including, but not limited to, renewable natural gas and hydrogen. The projected O&M expenses for the Gas Engineering Asset Planning department for the 12 months ending September 30, 2025, is $409,000, as shown on Exhibit A-95 (KAP-2), page 1, line 4, and consists of the O&M portion of the salaries and expenses for engineers, designers, analysts, and other support staff needed to complete the necessary engineering planning and permitting of projects outlined in the NGDP.

Q. Please describe the activities of the System Integrity department.

A. System Integrity is responsible for the integrity management programs for the Company. This includes the following programs: Transmission Integrity Management Program (“TIMP”), Distribution Integrity Management Program (“DIMP”), and SIMP. These programs ensure the integrity of the Transmission, Distribution, and Storage Assets. My testimony covers the labor and expense costs for staffing of the System Integrity department and the O&M expenses for the SIMP. The other System Integrity programs described above are sponsored by Company witnesses Michael P. Griffin and Timothy K. Joyce. The projected O&M expenses for the System Integrity department for the 12 months ending September 30, 2025, is $1,958,000, as shown on Exhibit A-95 (KAP-2), page 2, line 5, and consists of the O&M portion of the salaries and expenses for engineers, designers, analysts, and other support staff needed to meet the design and planning needs of the NGDP including the implementation of the Transmission and Storage Probabilistic Risk Models and meeting compliance requirements of the Company's integrity management programs.

In addition to the System Integrity staffing requirements, the SIMP was created in response to a new Pipeline and Hazardous Materials Safety Administration ("PHMSA") final rule issued on February 12, 2020. The SIMP O&M expenses for the 12 months ending September 30, 2025, are shown on Exhibit A-95 (KAP-2), page 2, line 7.

Q. What is the basis for determining the $5,341,000 in SIMP O&M expenses in the test year 12 months ending September 30, 2025, for this program?

A. On December 9, 2016, PHMSA issued an Interim Final Rule ("IFR") titled "Pipeline Safety: Safety of Underground Natural Gas Storage Facilities." This IFR included a new Rule 192.12 Underground Natural Gas Storage Facilities ("UNGSF") and was enacted as a congressionally mandated response to the natural gas leak incident at the Aliso Canyon facility on October 23, 2015. Rule 192.12 became effective January 18, 2017, and was incorporated by reference in the consensus document American Petroleum Institute Recommended Practice ("API RP") 1171: Functional Integrity of Natural Gas Storage in Depleted Hydrocarbon Reservoirs and Aquifer Reservoirs. On February 12, 2020, PHMSA issued a Final Rule reinforcing its minimum safety standards for underground natural gas storage facilities and including additional requirements and clarifications. The effective date of this Final Rule was March 13, 2020.

As a result, Consumers Energy has developed the SIMP to comply with the federal regulations. The Company owns and operates approximately 826 gas storage wells that fall under the scope of SIMP. The SIMP has several O&M components necessary to execute the program. The O&M components address the expenses required for the well plugging program, atmospheric corrosion protection (painting) of rehabilitated wells, risk reduction, annular pressure remediation, well re-assessment, and gas storage field analysis. The projected O&M costs for the SIMP in the test year total $5,341,000.

Q. Please describe the well plugging portion of the SIMP funding requirements.

A. To comply with PHMSA Regulation 192.12 and API RP 1171, Consumers Energy has created a program to perform baseline assessment of well integrity as part of the Well Rehabilitation Program sponsored by Company witness Joyce. For all plugged wells within the storage reservoir boundary, the Company must further comply with plugged well monitoring requirements including plugged wells owned by the Company and plugged wells owned by other operators or producers. The monitoring of plugged wells requires visual and instrumented observation of the plugged well sites for any indication of methane leaks. The field monitoring will include 86 plugged wells in the test year. The O&M costs associated with the well plugging portion of the SIMP in the test year total $233,351 and are based on historical cost of performing monitoring including the additional cost for access to third-party wells.

Q. Please describe the well rehabilitation atmospheric corrosion portion of the SIMP funding requirements.

A. The well rehabilitation portion of the SIMP performs baseline assessment and remediation of Consumers Energy's natural gas storage wells. The O&M funding requirement is for painting of above-grade equipment associated with the rehabilitated wells to provide atmospheric corrosion protection upon completion of the assessment and remediation of a well where an asset is not intended to be retired or replaced. The projected cost is derived from the configuration of the well for applied corrosion control measures such as paint applied by contractors and inspection to ensure applied coatings meet the application specifications. The O&M costs associated with the well rehabilitation atmospheric corrosion portion of the SIMP for the projected test year totals $374,540.

Q. Please describe the risk reduction portion of the SIMP funding requirements.

A. The risk reduction portion of SIMP is to address facilities and piping that have compliance and safety risks associated with them. These facilities are associated with the storage system and include sections of the storage pipelines, well lines, and farm tap setups that fall outside of the ability to replace as a part of the capital SIMP programs due to being typically short sections of pipe or fittings installed as part of the original installation. The risk reduction portion will be used to investigate, evaluate, replace, or retire facilities to reduce risk on the storage system. The projected cost addresses one third of the risk on the system that does not fall into other areas of SIMP and includes approximately 60 farm tap facilities, short sections of transmission piping, and well lines. The costs include records validation, field research and physical verification, piping and equipment upgrades, replacements, repairs, and other associated charges. The O&M costs associated with the risk reduction portion of the SIMP for the projected test year is $2,265,000.

Q. Please describe the gas storage annular pressure diagnostics and remediation portion of the SIMP funding requirements.

A. The annular pressure diagnostics and remediation portion of SIMP is the cost of diagnosing and remediating wells that have annular pressures trending toward or exceeding threshold pressures. Annular pressure is monitored as part of SIMP, and is a method to ensure integrity of the wells. Annular pressure outside of and trending toward threshold limits can indicate a loss of mechanical integrity or other failure requiring intervention. The repair funds are estimated based on historical spend for remediation of annular pressures, which typically requires testing, replacement of wellhead seals, replacing or adding a well packer, or similar material replacements or repairs. The O&M costs associated with the annular pressure diagnostics and remediation portion of the SIMP for the projected test year totals $478,934 and is based on historical cost.

Q. Please describe the well re-assessment portion of the SIMP funding requirements.

A. The well re-assessment portion of SIMP is initiated seven years after the initial baseline assessment has occurred, in accordance with PHMSA Regulation 192.12 and API RP 1171. The well re-assessment portion starts in 2024 for the wells that were baseline assessed in 2017, and in 2025 for the wells that were baselined assessed in 2018. The re-assessment will consist of well logging and Mechanical Integrity Testing ("MIT") of the subject wells based on the configuration of each well and well history, and includes any remedial and necessary actions. There are a total of 111 wells to be re-assessed in 2025, and all of them will be inspected and will incur costs in the test year. The O&M costs associated with the well re-assessment portion of the SIMP for the projected test year totals $1,775,175.

Q. Please describe the gas storage field analysis portion of the SIMP funding requirements.

A. The gas storage field analysis portion of the SIMP is an analysis used to model the storage system deliverability, considerate of all SIMP programs, and other related integrity programs. The purpose of the analysis is to better model the capability and needs of the existing storage system to enable right-sizing of the system and necessary equipment upgrades, including but not limited to: well deliverability, field deliverability, pipeline replacements/retirements, liquid separation, and gas conditioning equipment. The analysis will support system risk reduction through optimization by matching existing and future system needs with the capabilities and future capabilities of the gas storage system. The gas storage field analysis portion of the SIMP for the projected test year totals $214,000.

Q. Please describe the activities of the Gas Compression Engineering department.

A. Gas Compression Engineering is responsible for the engineering, design, and technical support of the Company's compressor station assets. This team is also responsible for asset planning for all capital investments within the existing compression fleet. These capital investments are sponsored by Company witness Joyce. The projected O&M expenses for the Gas Compression Engineering department for the 12 months ending September 30, 2025, is $845,000, as shown on Exhibit A-95 (KAP-2), page 2, line 6, and consists of the O&M portion of the salaries and expenses for engineers, designers, analysts, and other support staff needed to meet the design and planning needs of the NGDP.

Q. What operating sections are included in Gas Engineering Support?

A. Gas Engineering Support consists of five departments which I will describe more fully below. They are:

- Gas Strategy;
- Gas Regulatory and Compliance;
- Geospatial Management and Data Quality (which includes the Geospatial Inventory and Modeling Program);
- Damage Claims/Prevention; and
- Enterprise Corrective Action Program.

Q. Please describe the activities of the Gas Strategy department.

A. Gas Strategy provides asset strategy, business support, financial analysis, and business performance measurement for the Company's compression, storage, transmission, and distribution facilities. This department is responsible for the development, implementation, and support of the long-term strategy for the natural gas system, and the development of the NGDP. This department ensures the overall goals and outcomes developed in the NGDP align with the Company's strategy. Gas Strategy includes the individuals responsible for ensuring that financial analysis aligns with the portfolio planning services, including long-term financial planning and long-term strategy. The projected O&M expenses for the Gas Strategy department for the 12 months ending September 30, 2025, is $89,000, as shown on Exhibit A-95 (KAP-2), page 2, line 8, and consists of the O&M portion of the salaries and expenses for strategy managers and analysts needed to support the financial analysis and business performance measurements necessary to ensure implementation of the NGDP as well as the long-term strategy development for the natural gas system.

Q. Please describe the activities of the Gas Regulatory and Compliance department.

A. Gas Regulatory and Compliance interfaces with the MPSC Gas Safety Staff and the Federal Office of Pipeline Safety on regulatory compliance matters. This includes regulatory audits, inspection activities, gas standards work, and submission of periodic and incident reports in accordance with both federal and state requirements. Gas Regulatory and Compliance supports compliance-related programs and documents, including Transmission Integrity Management, Distribution Integrity Management, Gas Operations Procedures, Public Awareness, and Damage Prevention. Effective September 1, 2023, the

AMD team was integrated into the Gas Regulatory and Compliance department from the Operations Compliance and Controls department. The Gas Regulatory and Compliance department is managing the Company's implementation of the API RP 1173 – Pipeline Safety Management Systems which is the Company's Gas Safety Management System ("GSMS") and the AMD Program. The salaries and expenses associated with the Gas Regulatory and Compliance department for the 12 months ending September 30, 2025, is $967,000 as shown on Exhibit A-95 (KAP-2), page 3, line 9. The 2023 projected expenses for this department, shown on Exhibit A-95 (KAP-2), page 3, column c, line 9, include the September through December 2023 addition of the AMD team. The 2022 historic year actual and the January through August 2023 projected expenses for the AMD team are included in Company witness Pnacek's Exhibit A-104 (JPP-4) page 1, line 1, Compliance and Controls.

Q. Please describe the activities of the Geospatial Management and Data Quality department.

A. The Geospatial Management and Data Quality department is responsible for creating and maintaining the Geospatial Information Systems ("GIS") & Service Information Management System ("SIMS") databases for gas distribution, transmission, storage, service, and regulation systems, and for supporting strategic and operating capacity planning, performance, asset management, and regulatory reporting requirements.

The Geospatial Management and Data Quality department also supports the Company's gas technical records, working closely with operations and engineering teams to store, protect, retrieve, and, when appropriate, destroy records according to operational and regulatory requirements. In alignment with the above scope, the team has dedicated roles to manage system administration of Consumers Energy's Gas Engineering Content Management software. The O&M expenses for the Geospatial Management and Data Quality department for the 12 months ending September 30, 2025, is $765,000, as shown on Exhibit A-95 (KAP-2), page 3, line 10, and consists of the O&M portion of the salaries and expenses of managers and their Company-employed and contracted staff needed to support the increased asset records management to meet the compliance workload driven by the NGDP, and to ensure Company records are compliant and current, enabling employees and other end users to have comprehensive access to current and accurate mapping and correct information in a timely and cost-effective manner, all contributing to increased pipeline safety.

Additionally, this department is responsible for the Geospatial Inventory and Modeling Program, which includes the Gas Compliance Code Program – Service Information Mapping System ("GCCP - SIMS") project, and the Utility Network implementation. The O&M expenses for the Geospatial Inventory and Modeling Program within the Geospatial Management and Data Quality department for the 12 months ending September 30, 2025, is $2,681,000, as shown on Exhibit A-95 (KAP-2), page 3, line 11.

Q. What is the basis for determining the $2,681,000 of projected O&M expenses in the test year 12 months ending September 30, 2025, for the Geospatial Inventory and Modeling Program?

A. The Geospatial Inventory and Modeling Program includes the GCCP - SIMS project and the Utility Network project. This program was created to modernize and transform the Company's GIS records and systems. These projects have a capital and O&M component. The projected capital expenditures and project benefits are described in further detail in the

Gas Operations Other Program later in my testimony. The O&M expenses for the GCCP - SIMS project is $754,555 and for the Utility Network project is $1,715,258 in the test year 12 months ending September 30, 2025. The projected costs for the GCCP - SIMS project were determined based on information provided to the Company in response to a Request for Proposal that was performed with several vendors in 2017, along with contracts put in place in 2022. The projected costs are updated annually as more work is defined and developed for the future state of the end-to-end solution. The migration of gas service information to GIS is projected to be complete in 2025. Total Utility Network transformation costs were estimated through an assessment performed in 2019 and 2020 in collaboration with Esri Professional Services ("Esri"). Esri prepared a high-level Utility Network migration strategy through a series of workshops in which the Company's business requirements, processes, and technical infrastructure were assessed to determine the scale and complexity of the migration. Upon completion of the workshops, Esri provided the Company with a written planning strategy along with a project schedule and cost estimate. In 2022 and 2023, the Company executed a Request for Proposal to further develop a business plan. The Company's current and future state was assessed along with performing a GIS data analysis to aid in further refining the projected costs, resource requirements, project timeline, and overall transformation strategy. Due to the high level of impact and complexity of the change to people, processes, and technology, the Gas Utility Network transformation is planned to be complete in 2026.

Also included in the Geospatial Inventory and Modeling Program is the Gas Compliance Code Program – IT Enhancements, which are updates to compliance software required to meet regulatory requirements. This project does not have a capital component and will require O&M funding in the amount of $211,000 in the test year 12 months ending September 30, 2025.

Q. Please describe the activities of the Damage Prevention and Claims department.

A. Effective September 1, 2023, the Damage Prevention and Claims department was integrated into the Gas Engineering and Supply department from the Gas Operations Compliance and Controls department. The Damage Prevention and Claims department provides oversight of the Company's staking and locating of underground facilities in accordance with 811 MISS DIG regulations. This includes the Company's Gas Public Awareness Program. The O&M expenses for the Damage Prevention and Claims department for the 12 months ending September 30, 2025, is $1,001,000, as shown on Exhibit A-95 (KAP-2), page 3, line 12, and consists of the O&M portion of the salaries and expenses for roles needed to support damage prevention/claims activities and liaison with external agencies and excavators, and the public promoting of education and awareness to proactively prevent and reduce third-party damages. The 2023 projected expenses for this department shown on page 3, column (c), line 12 of the exhibit, represent expenses from September through December 2023. The 2022 historic year actuals and the January through August 2023 projected expenses are included in Company witness Pnacek's Exhibit A-104 (JPP-4) page 1, line 1, Compliance and Controls.

Q. Please describe the activities of the ECAP department.

A. Effective September 1, 2023, the ECAP department was integrated into the Gas Engineering and Supply department from the Operations Compliance and Controls department. The ECAP was initiated at Consumers Energy in 2020 as an enterprise-wide issue management and compliance program supporting safe and excellent operations. The structured platform and methodology allow for transparency in reporting issues, identifying trends, and closing compliance and safety gaps through corrective actions and controls, based upon associated risk thresholds. ECAP's functionality for managing processes and performance, as well as analyzing data, focuses risk reduction efforts, informs operational business decisions, and promotes the integrity and deliverability of the energy infrastructure. Starting in 2022, ECAP supported stakeholders in Gas Operations and Engineering to maintain adherence to GSMS standards established in API RP 1173. ECAP is responsible for the management of an integrated safety assurance approach to proactively sustain and assess the needs of the Company's operational compliance performance. The program implements a common process and technology that fully integrates corrective and preventative action ("CAPA") management. The O&M portion of the salaries and expenses associated with the ECAP department is $205,000, for the 12 months ending September 30, 2025, as shown on Exhibit A-95 (KAP-2), page 4, line 13. The 2023 projected expenses for this department shown on page 4, column (c), line 13 of this exhibit, represent September through December 2023. The 2022 historic year actuals and the January through August 2023 projected expenses are included in Company witness Pnacek's Exhibit A-104 (JPP-4) page 1, line 1, Compliance and Controls.

Q. What operating sections are included in Gas Management Services?

A. Gas Management Services is responsible for four major functions:

- Gas Control;
- Gas System and Operations Planning;
- Gas Supply; and
- Gas Transportation, Customer Choice, and Measurement.

Gas Control is responsible for:

- The centralized Gas Control Room operation, which monitors and controls the gas transmission system and monitors key points on the distribution system on a 24/7 basis, following PHMSA Title 49 CFR 192.631 (control room management);
- Monitoring scheduled third-party pipeline supply; and
- Dispatching compression and storage assets to ensure customer supply is met within the Transmission system's design limits and monitoring portions of the Distribution system.

Gas System and Operations Planning is responsible for:

- Transmission and storage capacity studies;
- Facility and operational improvements to meet changing supply and customer loads;
- Reporting operational data;
- Assisting in development of business cases for major system modifications related to the Company's gas transmission, storage, and compression system;
- The preparation of natural gas supply and storage dispatch plans;
- The coordination of the Gas Cost Recovery ("GCR") plan and GCR Reconciliation with the Company's operational plans; and
- Administration of interconnect agreements.

The Gas Supply section is responsible for:

- Obtaining reliable and reasonably priced gas supply for the Company's GCR or Sales customers;
- Negotiation and administration of all related gas supplier, transportation, and Buy/Sell agreements, and Asset Management contracts; and
- Tracking and projecting the cost of gas and related inventory valuations, Gas Supply coordinates the gas purchase planning related to GCR plans and reconciliations.

The Gas Transportation and Measurement section is responsible for:

- The management of the Company's Gas Customer Choice ("GCC") Program, including preparation of required deliveries for GCC Suppliers, and monthly GCC remittance statements and annual reconciliations;

- The daily management of the gas transportation activity at the Company, including the daily balancing and confirmation of gas nominations and gas transportation contract administration; and

- The preparation of the Gas Control Operations Summary and various internal and external reports, all of which make up the foundation of volumetric accounting on the Company's gas transmission and storage system.

The salaries and expenses associated with the Gas Management Services department for the 12 months ending September 30, 2025, is $3,969,000, as shown on Exhibit A-95 (KAP-2), page 4, line 14 and consists of the O&M portion of the salaries and expenses for engineers and gas control staff needed for outage coordination, scheduling, and system planning activities necessary to support the capital, O&M, system control, and system analytics plans in the NGDP.

GAS DISTRIBUTION CAPITAL EXPENDITURES

Q. Please describe the Company's projections of capital expenditures for Gas Distribution – Material Condition.

A. As shown on Exhibit A-12 (KAP-3), Schedule B-5.9, the Gas Distribution capital expenditures I am sponsoring were $347,150,000 in 2022, and are projected to be $291,668,000 in 2023; $223,675,000 for the nine months ending September 30, 2024; and $350,845,000 for the 12 months ending September 30, 2025, as set forth on this exhibit on line 3, columns (b), (c), (d), and (f), respectively. These projections are based upon the necessary requirements to meet the Company's objectives of operating a system that is safe, reliable, affordable, and clean.

Q. Please list the major programs within the Gas Distribution capital expenditures.

A. The major programs, as shown on Exhibit A-12 (KAP-3), Schedule B-5.9 and Exhibit A-12 (LDW-1), Schedule B-5.10, are:

- New Business;
- Asset Relocation;
- Regulatory Compliance;
- Material Condition;
- Capacity/Deliverability; and
- Gas Operations Other.

Several of these major programs have a gas distribution and a gas transmission component to them. My direct testimony represents only the gas distribution portion of the Material Condition and Gas Operations Other programs. The direct testimony of Company witness Warriner represents the gas distribution portion of the remaining programs listed above. The direct testimony of Company witnesses Griffin and Joyce represent additional components of the gas transmission system as well as distribution regulating stations, compression, and storage systems.

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.

1. <u>Material Condition</u>

Q. Please describe the capital expenditures relating to the Material Condition Program set forth on Exhibit A-12 (KAP-3), Schedule B-5.9, line 1.

A. Material Condition Program expenditures are used to improve the natural gas distribution system integrity, reduce service interruptions impacting customers, and replace leaking and vintage gas distribution facilities. Reducing the number of leaks improves reliability, reduces methane emissions to the atmosphere, and enhances public safety. The expenditures in this program include the EIRP, the VSR Program, and system enhancements that are prioritized by risk to improve safety and gain operational efficiencies through replacement of lower performing gas distribution assets.

The expenditures in this program also include capital replacements due to leaks and system damages, represented by the Material Condition Renewals Program, as well as emergent gas service and main replacement projects driven by conditions observed in the field, represented by the Material Condition Non-Modeled Program, and business customer capital meter and meter stand replacements represented by the Commercial and Industrial Meters Program. The projects and expenditures for these five programs are described in more detail below. As shown on Exhibit A-12 (KAP-3), Schedule B-5.9, line 1, the capital expenditures for these five programs were $331,003,000 in 2022, and are projected to be $283,297,000 in 2023; $214,479,000 for the nine months ending September 30, 2024; and $330,947,000 for the test year 12 months ending September 30, 2025, as set forth on this exhibit on line 1, columns (b), (c), (d), and (f), respectively. The expenditures for the Material Condition Program are further detailed in Exhibit A-96 (KAP-4).

Q. Please describe the EIRP.

A. Beginning in 2012, the Company implemented the EIRP to ensure continued customer safety and reliable system operation as part of the DIMP. The EIRP replaces the Company's highest risk materials as classified by PHMSA, including all cast iron, wrought iron, Threaded and Coupled ("T&C"), oxyacetylene welded, copper, and bare steel distribution main with more reliable, lower maintenance plastic and steel main, and replaces (in the case of older metallic materials) or ties-over (plastic) services to the new main.

The program scope includes the following:

- Replacement of all cast iron main;
- Replacement of all bare, oxyacetylene welded, T&C, Xtrube, and cathodically unprotected steel main;
- Replacement of all copper main;
- Replacement of metallic service materials associated with the main replacement projects;
- Replacement of approximately 100 miles of transmission pipeline located in high consequence areas and transmission pipelines operated on the Distribution System;
- Replacement of approximately 70 miles of low frequency electric resistance weld pipe in the Company's Transmission and Storage fields; and
- As included in the Company's NGDP, replacement of approximately 108 miles of pipe at Standard Pressure on the Company's gas system that is not covered in the vintage main miles. The Company intends to complete this work and include it as part of planned EIRP work.

In addition to safety and reliability improvements, replacement of cast iron piping will enable the reduction and eventual elimination of the standard pressure system, allowing these areas to operate at higher, more efficient pressures while lowering gas losses, reducing the potential for water infiltration, and reducing greenhouse emissions. Upgrades to more efficient pressures may require modifications to regulator facilities under this program. Eliminating standard pressure also allows for the elimination of certain regulating stations that feed the standard pressure system, which lowers operating costs for those systems.

EIRP projects are selected by the gas engineering teams using a risk model that assesses the risks and threats of each pipe segment, according to the Company's DIMP. The risk model helps prioritize system replacements to eliminate the highest risk distribution pipe first, to maximize the system risk reduction in any given year. The

Company uses this risk-based approach, combined with subject matter expert input, to select EIRP replacement projects that eliminate vintage mains and standard pressure systems. The EIRP investment ensures reliability and the safety of customers and the public. The well-planned, thoughtful execution of the EIRP is a more cost-effective approach than being forced into replacement under emergent conditions. The Company continues to evaluate the risks to the distribution system along with the overall timeframe projected to replace higher risk pipe.

Q. Please describe the progress of the EIRP.

A. Since the EIRP began in 2012 through the calendar year ended 2022, the program has retired 703 miles of the vintage gas pipe identified for replacement as shown in Table 1. In addition to the EIRP, other programs, like Asset Relocation – Civic Improvement and Material Condition Non-Modeled, also eliminate vintage pipe. In any given year, the number of miles retired for each material will vary based on the mix of investment between steel and plastic projects. The Company uses a risk model to optimize the investment to eliminate higher risk gas mains first. At the end of calendar year 2022, the status for each of the main types is detailed in the following bullets:

- Copper main – Eliminated the last known copper main segments in 2018;
- Xtrube main – Eliminated the last known Xtrube main segments in 2018;
- Cast iron main – Eliminated 254.0 of 580.0 miles by the EIRP through 12/31/2022;
- Wrought iron main – Eliminated 5.1 of 21.6 miles by the EIRP through 12/31/2022;
- Bare steel main (including oxyacetylene welded bare steel) – Eliminated 264.3 of 1033.4 miles by the EIRP through 12/31/2022; and
- T&C main – Eliminated 119.1 of 1061.7 miles by the EIRP through 12/31/2022.

Per the Company's NGDP, the EIRP is currently planned to be completed by the end of 2035.

See Table 1 below for a summary of pipe retired each year by the EIRP Program and the cumulative pipe retired by other programs.

Table 1: Miles of EIRP Main Pipe Retired by Year

MILES OF EIRP CLASSIFIED MAIN PIPE REPLACED BY YEAR								
PIPE TYPE:	Miles of Pipe by Pipe Type in EIRP Program Scope	EIRP Actuals (2012 - 2019)[1]	EIRP 2020 Actuals[1]	EIRP 2021 Actuals[1]	EIRP 2022 Actuals[1]	Cumulative EIRP Retired as of 12/31/22[1]	Estimated Cumulative Retired by Other Programs as of 12/31/22	Est. Miles Remaining as of 12/31/22
TOTAL:	2869.2	437.2	62.5	119.1	84.3	703.0	367.2	1,799.0
Cast Iron	580	166.5	13.9	50.6	23.0	254.0	99.1	226.9
Bare Steel	1033.4	135.2	26.6	46.4	56.1	264.3	107.2	662.0
Threaded & Coupled	1061.7	80.3	19.8	14.9	4.2	119.1	154.8	787.8
Wrought Iron	21.6	4.7	0.0	0.4	0.0	5.1	5.6	11.0
X-trube	0.9	0.9	0.0	0.0	0.0	0.9	0.0	0.0
Copper	1.6	0.6	0.0	0.0	0.0	0.6	0.5	0.0
Coated & Wrapped on Standard Pressure[3]	108.35	0.0	0.0	2.2	11.3	13.5		
TOD	100	10.6	2.3	6.7	1.1	20.6		
LFERW	70	38.4	0.0	0.0	0.0	38.4		
Additional Pipe Replacement:								
Plastic[2]		8.4	1.7	3.2	6.6	19.9		
Coated & Wrapped[2]		76.1	7.4	12.4	39.5	135.3		

Notes:

1) Does not include miles of EIRP pipe type that were replaced as part of other programs like Civic Improvement or Emergent CE Initiated.
2) It is necessary to replace some coated and wrapped steel and plastic pipe as part of EIRP projects due to the configuration of the system, project constructability code 3 condition, but coated and wrapped and plastic are not EIRP targeted pipe type.
3) Coated & Wrapped steel pipe on standard pressure does qualify under ERIP while Coated & Wrapped steel pipe on medium pressure does not qualify under EIRP

In 2022, the Company completed nine projects using the grid approach, which plans for and constructs large scale EIRP projects (typically 15 to 25 miles of distribution pipeline). Opportunities to use the grid approach for future projects are decreasing due to the location of higher risk pipe. A shift back to more segment projects will begin in 2025. The Company will continue to apply efficiencies achieved through prior years (described later in this testimony) to mitigate unit costs.

Q. Please explain the difference between replaced or retired pipe and installed pipe for the EIRP and why cost is based on installed pipe.

A. Replaced or retired pipe refers to the amount of vintage pipe existing on the Company's gas system prior to EIRP project construction that will be replaced by new installed pipe and retired (abandoned in place) upon completion of the EIRP project construction. Miles of replaced or retired pipe by the EIRP is included in Table 1 above and as part of the Company's annual performance report filings. Installed pipe refers to the amount of new pipe that is added to the Company's gas system to replace the vintage material pipe being retired upon completion of the EIRP project construction. The EIRP project cost is based on installed pipe, as the EIRP project activities are related to the planning, design, and construction for the new pipe installation. There is a small amount of construction time related to the retirement activity to safely cut and cap off the old vintage pipe to retire the pipe (abandon in place). The Company charges 2% of EIRP project cost to cost of removal ("COR") to cover the cost related to the retirement activities, which is included in the Company's depreciation rate cases, and not included as part of the EIRP project cost in this testimony. The EIRP project cost provided in this testimony are without COR and related to the project planning, design, construction, and other activities to support the new pipe installation.

Q. What were the results of the 2022 EIRP projects?

A. In 2022, the Company constructed nine EIRP projects using the grid approach, and one project using the Segment approach. See Table 2 below for a summary of the scope of the 2022 EIRP project work completed.

Table 2: 2022 EIRP Program Completed Project Work

Project Type	# Projects	Installed Pipe (miles)	Service Counts
Grid Projects	9	161.1	14,025
Segment Projects	1	1.0	49
Steel/TOD Projects	0	0	0
Total	**10**	**162.1**	**14,074**

As shown in Exhibit A-98 (KAP-6), the 2022 EIRP total spend was $248.149 million. Program costs include previous year projects carryover expenses, current year project expenditures, and future year project expenditures. The previous year project carryover expenses include activities such as pipe installation, pipe retirement, and surface restoration that could not be completed during the prior construction year. In addition to new pipe installation, the current year project expenditures include standard pressure system conversions and meter move out activities, which have no attributed miles or service counts. However, these activities are necessary for project completion. The future year project expenditures include activities such as engineering, survey, and construction mobilization that must be completed prior to the start of construction. Like standard pressure system conversions and meter move-outs, these necessary activities result in additional project expenditures with no associated installed miles, increasing the total EIRP average cost per mile in a given year. As shown in Exhibit A-98 (KAP-6), for 2022, a total of 162.1 miles were installed which calculates to an average cost per mile of $1.53 million per mile. The 2022 cost per mile represents a 4% increase over the 2021 EIRP cost per mile of $1.47 million and is below the 5-year average unit cost of $1.57 million per mile installed. The data for 2018 – 2022 is shown in Exhibit A-99 (KAP-7).

Q. What factors influence the installed cost per mile for EIRP distribution projects?

A. There are many factors that can influence the installed cost per mile of EIRP distribution projects. When looking at unit cost data, it is important to consider these factors to help understand the complexity and variability of costs incurred in performing the project work. Some of the key factors to consider are listed below.

- Location – The urban density of the area where a project is executed has a significant influence on the cost of that project. Some of the differences include:
  - Rural projects – Little or no hard surface (sidewalks), few obstacles in the ground, typically lower permitting costs and requirements;
  - Suburban projects – Mostly residential and some commercial services, moderate hard surface with potential for installation under sidewalks or streets, moderate traffic control and safety services cost, low to moderate obstacles in the ground (other service provider wires, pipes, etc.), moderate permitting cost and number of requirements;
  - Urban projects – Commercial and residential buildings and services, significant hard surface requiring installation under sidewalks and streets, high traffic control and safety services cost, high obstacles in the ground (other service provider wires, pipes, etc.), moderate to high permitting cost and number of requirements; and
  - Inner city projects – Buildings and commercial services, significant hard surface requiring installation under sidewalks and streets, high traffic control and safety services cost, significant obstacles in the ground (other service provider wires, pipes, etc.), high permitting costs and number of requirements.
- Number of associated services – The average number of services to be renewed with the installed main is a significant driver of project cost, as every service renewal requires material and labor time, and contributes to the required support services needed for a project (such as sewer locates, hydrovac excavation, aggregates, and soft and hard surface restoration). A project with 50 services per mile will contribute less cost related to service renewals than a project with 100 services per mile.
  - Additional considerations include if the services are long side (crossing the road from the installed main location) or short side (same side of the road as the installed main), the number of services on a project that are tie-over (connecting a previously installed plastic service line to the new installed main) versus renewal (replacing vintage service pipe), and whether a service is residential or commercial (requires a different meter and larger service pipe diameter than residential).
  - Completion of long side services typically takes longer and costs more than short side, renewals typically take longer and cost more than tie-overs, and commercial services typically take longer and cost more than residential services.

   - Commercial services require more costly equipment and material, a higher skilled employee, and more coordination with the business owner.
   - Exhibit A-99 (KAP-7) provides data on services worked on through the EIRP Program for 2018 - 2022 and a projection of 2023 through 2025 sorted by Michigan regional locations where the work is located (SW is primarily the Jackson, Lansing, Kalamazoo areas; NE is primarily the Flint, Saginaw, Midland, and Bay City areas; and SE is primarily the Royal Oak, Macomb, Livonia areas).

- Pipe type – High pressure steel segment and Transmission Operated by Distribution ("TOD") pipe installation is significantly more complex and expensive than plastic pipe installation. In addition, pipe being retired may cause cost variations as well. For example, steel pipe may require end caps and pressure control fittings to be installed before retiring, whereas cast iron requires less resources to retire.

- Pipe size – As the size of installed pipe increases, the cost of material, labor, and associated supporting services also increase due to additional time, and in some cases, higher skilled labor, required to install the larger size pipe.
   - The most common main pipe size installed on EIRP projects is 2-inch plastic; however, a large amount of 4-inch and 6-inch plastic is also installed.
   - For larger plastic pipe, typically 8-inch and larger (but also some 6-inch), the pipe to be installed is not in coil form (typically 500 ft in length) but is in individual segments or "sticks" (typically 40 ft). This requires more fusing time for these lengths as well as a more complex fusing process and equipment (hydraulic fusing).
   - Steel pipe size installed varies based on the design requirements of the project and is typically 10-inch or larger.
   - Tables 3 and 4 below provide data on the feet of pipe installed through the EIRP Program for the years 2017 through 2022.

Table 3: EIRP Feet of Pipe Installed by Size, Type, Year

Year/Size	2"P	4"P	6"P	8-12"P	2-6"S	8"S	10"S	12"S	16"S	Total
2017	344,644	44,231	11,768	3,231	700	0	0	225	0	**404,799**
2018	195,527	25,216	30,939	2	129	0	10,057	546	16,685	**279,101**
2019	192,783	32,619	32,535	1,526	386	0	8,121	12	0	**267,982**
2020	303,001	34,612	18,831	3,572	0	4,127	7,637	4,371	0	**376,151**
2021	698,773	44,554	52,279	10,620	922	428	100	22,426	0	**830,102**
2022	699,278	62,528	76,995	9,360	1,283	6,503	2	0	0	**855,949**
Total	**2,434,006**	**243,760**	**223,347**	**28,311**	**3,420**	**11,058**	**25,917**	**27,580**	**16,685**	**3,014,084**

Table 4: EIRP % of Pipe Installed by Size, Type, Year

Year/Size	2"P	4"P	6"P	8-12"P	2-6"S	8"S	10"S	12"S	16"S	Total
2017	85.1%	10.9%	2.9%	0.8%	0.2%	0.0%	0.0%	0.1%	0.0%	**100%**
2018	70.1%	9.0%	11.1%	0.0%	0.0%	0.0%	3.6%	0.2%	6.0%	**100%**
2019	71.9%	12.2%	12.1%	0.6%	0.1%	0.0%	3.0%	0.0%	0.0%	**100%**
2020	80.6%	9.2%	5.0%	0.9%	0.0%	1.1%	2.0%	1.2%	0.0%	**100%**
2021	84.2%	5.4%	6.3%	1.3%	0.1%	0.1%	0.0%	2.7%	0.0%	**100%**
2022	81.7%	7.3%	9.0%	1.1%	0.1%	0.8%	0.0%	0.0%	0.0%	**100%**
Total	**80.8%**	**8.1%**	**7.4%**	**0.9%**	**0.1%**	**0.4%**	**0.9%**	**0.9%**	**0.6%**	**100%**

- Permitting requirements – These vary from community to community and have the potential to significantly impact project costs. Municipalities have expanded the scope of permitting requirements, moving to more specific permitting (by address / premises), permitting fees have increased, and the more detailed requirements result in increased cost to projects. Also, some communities have placed permit conditions that required dual mains be installed on projects, resulting in significant increases to the cost of those projects.

- Time of year – Challenging weather conditions in the winter, spring, and late fall (such as cold, snow, thunderstorms, heavy wind and rain, and poor ground conditions) can slow production and lead to increased project cost. Additionally, to reduce customer outages during critical heating seasons, the Company transitions into "winter operations" typically in early November (temperature dependent), which requires customer appointment and presence to perform the work. This adds costs as it can require labor resources to work during non-regular time, resulting in overtime and premium time.

Some additional drivers of costs include:

- Sewer location services – As with all utilities, Consumers Energy locates underground facilities in advance of construction work. Locating sewer mains, laterals, and services helps to protect those facilities from damage such as cross-bores and leaves customer sewer lines intact. Sewer locating services are contracted to third-party vendors for this work and are primarily performed for the location of sewer mains at the onset of the program.

- Increasing permitting cost – Over time, municipalities have expanded the scope of permitting requirements within jurisdictions. This includes moving to more specific permitting (by address/premise) as opposed to "blanket permitting." In addition, permitting fees are increasing in general. The detailed requirements to obtain permits are also more stringent, leading to higher costs to meet these requirements.
- Dual main installation - Some communities have placed conditions in the permits for projects that require the Company to install main on both sides of the road when replacing and retiring the existing vintage main, which historically was only required to be installed on one side of the road. This requirement in effect doubles the footage of main pipe installation for a project, increasing the cost of materials, labor, and the supporting services for the project.
- Cross bore inspections – This work helps ensure that Company Gas facilities were not installed through sewer lines or other utilities while using horizontal directional drilling pipe installation techniques. Given the potential risk with cross bores, the Company is inspecting for them after construction work is completed (though all other underground facilities are now being located and marked) to ensure public safety, which is adding to costs.

Q. Will all the remaining EIRP Program work be completed using the grid approach?

A. No. It will always be necessary to have certain project work completed using the segment project approach. The grid approach can be used in areas where the Company has a high concentration of EIRP vintage main distribution pipe to be replaced, allowing for the design and planning of large projects. As EIRP work is completed in the high concentration areas, it will be necessary to complete the replacement of vintage main distribution pipe in areas where the Company only has a small amount of EIRP pipe to replace. The Company also considers pipe risk in its planning and project selection criteria, which will result in some amount of segment projects to be completed each year based on risk selection. The Company is also replacing high pressure steel pipe and TOD pipe as part of the EIRP, and that work is planned as segment projects. For the test year of October 1, 2024, through September 30, 2025, a significant amount of the planned project work to be completed by the EIRP will be using the segment project approach and that is the basis for the Company's current test year cost projection.

Q. Is the Company planning to complete high pressure steel and other pipe replacement work within the EIRP Program?

A. Yes. The Company is also planning to complete high pressure steel and TOD steel pipe project work in 2023, 2024, and 2025. In 2023, this includes 6.8 miles of TOD high pressure steel pipe project work in the ALM3 project, and 1.2 miles of high-pressure steel segment pipe replacement included as part of the MAC3 grid project. In 2024, the GVL1 segment project includes 8.7 miles of high-pressure steel pipe installation and 6.1 miles of plastic pipe. In 2025, the Company is planning several projects with varying lengths of high-pressure steel segment pipe replacement which totals 20.8 miles.

Q. Has the Company taken actions to improve the cost per mile in the EIRP since the filing of MPSC Case No. U-21308?

A. Yes, the Company has implemented changes expected to maintain and potentially decrease the cost-per-mile for EIRP projects. The Company has taken the following actions:

- Engineering design timing – the Company has advanced the engineering design process so that EIRP project designs are completed the year prior to construction. This provides partnering teams such as Supply Chain, Permitting, and Operations more time to focus on planning the execution phase of the project, including materials management, sequencing of the construction phases, aligning workforce resources, arranging outside services, and other activities.

- Engineering designs – the Engineering team has implemented design checkpoints at thirty, sixty, and ninety percent completion milestones. The checkpoints provide opportunities for analysis, evaluation, and feedback by stakeholders, allowing the Engineering team to alter designs, if necessary, throughout the design process.

- Redistributed Company headquarters for the Gas Construction Workforce – the Company has redistributed the Gas Construction headquarters to move the workforce closer to the projects based on the updated work plans. This allows the workforce to be repositioned closer to the worksite, thereby reducing travel and other related costs.

- Gas Construction workforce stabilization – the workforce capacity is enhancing due to stability in the project layout, ability to pre-plan the work because of earlier designs, and productivity learnings from the EIRP grids.

Q. What cost per mile is the Company currently projecting for the EIRP projects?

A. The 2022 overall project cost-per-mile for installed plastic pipe was $1,394,223. For 2023, the EIRP is projecting an overall project cost-per-mile for installed plastic pipe of $1,680,794. The increased unit cost for 2023 is primarily driven by standard pressure conversion work in Flint, Lansing, and Bay City. This conversion work is necessary and requires additional hours to complete to ensure system integrity, employee and public safety, and regulatory compliance. The additional hours result in additional project expenditures with no associated installed miles, increasing the average cost per mile. For example, in 2023 the LAN5 project has a total of 75 conversions, compared to the 2022 LAN3 project which had no conversions. Included in the LAN5 conversion work is 3,700 feet of 8-inch pipe that required a five-hour pressure test to meet regulatory requirements. In addition to the standard pressure conversions, 2023 work scope includes larger diameter pipe size installations along busy multi-lane roads. As described earlier in my testimony, pipe size and location are factors that influence cost-per-mile. The larger diameter pipe installation and increased traffic controls and safety precautions needed due to the location increase the installation time required, which also increases the average cost-per-mile. Based on the process improvements described above, the Company is not escalating the cost-per-mile of plastic pipe for 2024 and 2025 for each region as shown on Exhibit A-99 (KAP-7), lines 47 and 56, respectively. Using the regional costs and the projected miles shown on Exhibit A-99 (KAP-7), lines 48 and 57, results in 2024 and 2025 projected cost-per-mile of $1,710,726, and $1,715,065, respectively. For 2023, 2024, and 2025, the Company is currently projecting per mile cost of pipe installed for high pressure steel segment projects and TOD projects of $3.80 million for each year. The projected cost is based on project scope and schedule information for 2023, 2024, and 2025, and is detailed in Exhibit A-99 (KAP-7).

Q. What is the Company's projected EIRP cost for the test year 12 months ending September 30, 2025?

A. The capital expenditures for EIRP were $248,149,447 in 2022 and are projected to be $208,232,000 for 2023; $157,943,000 for the nine months ending September 30, 2024; and $235,344,000 for the test year 12 months ending September 30, 2025, respectively. The costs for the EIRP are set forth on Exhibit A-96 (KAP-4), line 1. As shown below in Table 5, the test year projects 113.1 installed miles and renewal of 9,294 services.

Q. How many miles of distribution main installation and associated services does the Company plan to complete for the $235.2 million investment for the test year?

A. The Company prepares its estimates and projections based on calendar years running from January 1 through December 31. For the test year of October 1, 2024, through September 30, 2025, the Company combined a prorated projection for three months of 2024 and a prorated projection for the nine months of 2025 to provide the projected miles installed and service figures. The computation of the test year projection is based on a proration of 25% of the 2024 projection and 75% of the 2025 projection.

- The Company's projection for the calendar year 2024 includes 115.2 miles of main installation and 10,561 associated services. There is one segment project for 14.8 miles that includes 8.7 miles of high-pressure steel installation and 6.1 miles of plastic pipe installation and 478 associated services. The remaining 2024 projects include an additional 100.5 miles of plastic pipe installation.
- The Company's projection for the calendar year 2025 includes 112.4 miles of main installation and 8,888 associated services. This includes 91.6 miles of plastic pipe and 20.8 miles of high-pressure steel installation.
- While total miles and services are subject to final project designs and construction schedule, based on the current projections the test year is estimated to include approximately 113.1 miles of main installation and 9,294 associated services.

- Table 5 below provides a summary for the years 2022 through 2025 and the test year.

Table 5: EIRP 2022-2025 Scope and Cost

	Actual	**Projected**	**Projected**	**Projected**	**Projected**	**Projected**
Year	**2022**	**2023**	**2024**	**2025**	**9 months 1/1/24-9/30/24**	**Test Year 10/1/24 - 9/30/25**
Installed Pipe (Miles) [1]	**162.1**	**118.8**	**115.2**	**112.4**	**86.4**	**113.1**
Service Counts [1]	**14,074**	**9,241**	**10,561**	**8,888**	**7,921**	**9,294**
Capital Cost ($Millions) [2]	**$248.1**	**$208.3**	**$219.3**	**$241.6**	**$157.9**	**$235.3**

1 Includes total figures for all EIRP Program pipe installation and service counts for a year

2 Includes total EIRP capital spend without COR (cost of removal) for a year

Q. Please highlight the customer benefits of the vintage main distribution pipe and services replacement.

A. Major gas utilities throughout the country are embarking or undergoing major replacement projects, and some utilities are undertaking these projects under urgent timeframes due to incidents on their systems. The well-planned, thoughtful execution of the EIRP is a more cost-effective approach than being forced into replacement under emergent conditions. The Company continues to evaluate the risks to the distribution system along with the overall timeframe projected to replace higher risk pipe. Through December 31, 2022, the Company has replaced 703 miles of high-risk pipe identified for replacement through the EIRP, including 254 miles of cast iron and nearly 73,000 services replaced and retired to improve reliability and customer safety.

Q. Does the Company expect to meet the spending and installed miles requirements for EIRP from the MPSC Case No. U-21308 settlement agreement?

A. Yes, the Company expects to spend at or less than $214 million and install at least 110.8 miles of main replacement in the EIRP for the 12 months ending September 30, 2024.

Q. What is the purpose of the Material Condition Non-Modeled Program?

A. The projects in the Material Condition Non-Modeled Program are Company-initiated replacements to address emergent issues that must be resolved to comply with regulations or to ensure public and/or employee safety, and to target certain assets which may not rank as highly in the Company's risk modeling but whose replacements offer operational advantages to the Company and customers. Projects include issues associated with:

(i) Emergent Replacements / Leak Mitigation (i.e., main or service replacements due to active gas main damages, leaks, or temporary repairs that need to be resolved within the year);

(ii) Safety situations (i.e., saddle tee replacements);

(iii) Cathodic issues (i.e., cathodic shorts and atmospheric corrosion);

(iv) Company-initiated work to resolve standards discrepancies or customer issues (i.e., obsolete fittings or materials); and

(v) Projects based on operational improvements that may not be represented effectively in risk model results (and therefore are not EIRP projects).

The combination of these items results in hundreds of small replacements annually that are emergent in nature. The Company's capital expenditures for this program were $40,995,000 in 2022 and are projected to be $29,899,000, $23,306,000, and $34,695,000 for the year 2023; the nine months ending September 30, 2024; and the test year 12 months ending September 30, 2025, respectively. The costs for the Material Condition

Non-Modeled Program are set forth on Exhibit A-96 (KAP-4), line 2, and are further detailed later in this direct testimony.

Q. What is the impact of the NGDP on the Material Condition Non-Modeled Program?

A. The acceleration of vintage main replacement would have a significant impact on the Material Condition Non-Modeled Program, allowing the expenditures in this program to be reduced over time. However, with the current NGDP plans reflecting a lower investment in the EIRP Program, as adjusted in response to the Settlement Agreement in MPSC Case No. U-21148, the Company expects that the benefits of the EIRP replacement will take longer to be realized in the Material Condition Non-Modeled Program. Therefore, expenditures in this program are expected to remain consistent for the foreseeable future.

Additionally, the objectives outlined in the NGDP moves the Company toward finalizing EIRP project areas earlier to complete design, and align with affected municipalities and stakeholders, increasing the overall timeline allowed for design and construction planning. While this is beneficial overall, and will positively impact the Company's EIRP, it reduces the flexibility of the EIRP to add projects to address emergent issues on the system. This approach allows for a balanced mix of EIRP and Non-Modeled work to continue with the long-term plan and address system issues as they arise. Therefore, the Company is expecting a sustained level of Material Condition Non-Modeled spending to address emergent issues for the test year. Even though vintage infrastructure is being replaced, what remains continues to deteriorate. In the long-term, enough vintage material will be replaced to allow for reductions in this program, but with the extension of the EIRP to 2035, the Company expects that reduction to occur beyond the test year in this case.

Q. Please describe the importance of replacing the Company's standard pressure system through projects in the Material Condition Non-Modeled Program.

A. The Company's standard pressure system, also called utilization or low-pressure system, is made up primarily of cast iron main. In most instances, cast iron main was installed from the early 1900s through the 1920s. Due to the vintage and the construction method used when the cast iron gas mains were installed, the joints between each segment of main will leak if the pressure is too high. These same connection points allow water to infiltrate the gas main when the pressures in the ground are higher than the pressure of the gas inside the gas main. This causes customer interruptions and other operating problems.

Within a standard pressure system, some meters have a regulator on them but not all do, meaning that if an overpressure situation were to occur on the gas main, there is not a device at each home or business preventing that higher pressure from reaching the customer's equipment. There are several areas of the state where there are very few miles of cast iron main remaining in that area or system. Replacing these sections allows the operating pressure in that entire area to be increased, providing more reliable gas service to the customers in that area. Additionally, with elimination of the standard pressure system, each home or business will also now have a regulator installed, ensuring a consistent delivery pressure, and reducing the risk of higher pressures entering the premise. There were no large, planned cast iron elimination projects in this program in 2022, but in 2023 the Company completed the elimination of the Plymouth cast iron system. This was the last cast iron system within the Livonia headquarter area. Eliminating this standard pressure system will ensure a higher level of reliability for the customers in the area. Customers will benefit from a higher level of reliability with no water infiltration, and improved safety due to regulated meters and elimination of these vintage, more leak-prone facilities.

Q. Are there additional standard pressure replacements in the Company's future plans for the Material Condition Non-Modeled Program?

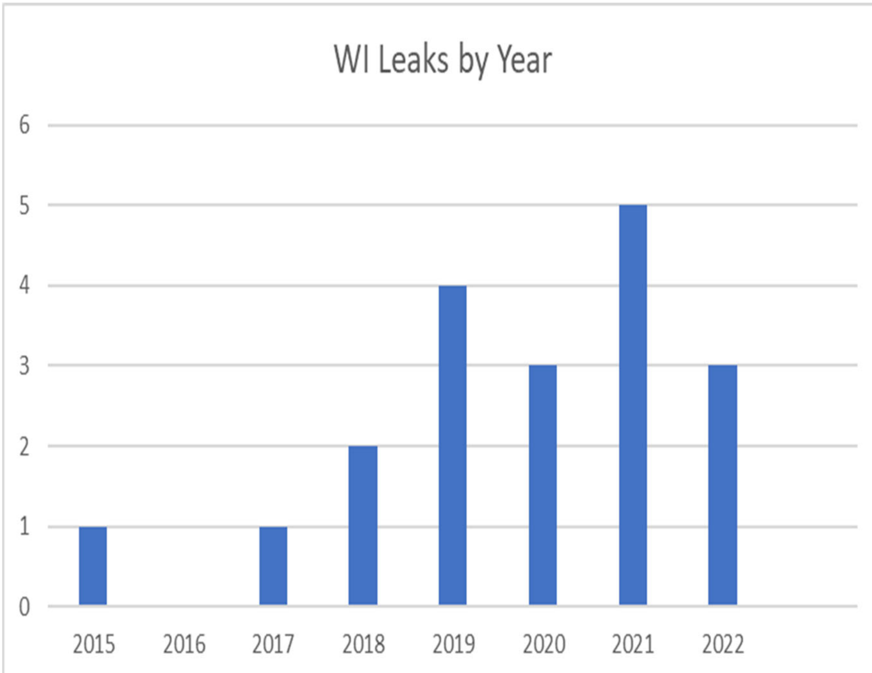
A. Not at this time, however, the Company will continue to evaluate risks across the gas system and prioritize as necessary, which may result in additional standard pressure replacement projects.

Q. Please describe the importance of replacing the Company's wrought iron gas main in the Material Condition Non-Modeled Program.

A. Wrought iron gas main was generally installed in the 1920s and 1930s. The annual DOT report combines cast iron and wrought iron together in a single line item, which indicates similar treatment and characteristic in the gas industry. Cast iron mains are only operated at low pressures, specifically less than 1 psig. Wrought iron mains, however, are part of the Company's medium pressure system, with MAOPs of up to 60 psig. Due to the way wrought iron was manufactured, its material properties are inconsistent and contains inclusions of lower quality materials. Therefore, it is not possible to choose a welding procedure that ensures the quality of the finished weld is adequate for use on the gas system. This leaves the Company with limited options for coupling or compression-style fittings when a leak or damage occurs on the wrought iron system, none of which are considered permanent repairs by the manufacturers of those fittings. The other alternative is replacement of the leaking main on an emergent basis.

Additionally, the Company has experienced an increasing number of leaks on the wrought iron system. Given that there are only 12 miles of this pipe material on the gas system, and the inability to make a permanent repair, the increasing leak rate is impactful.

Figure 1: Wrought Iron Pipeline Leaks Found 2015 – 2022



With only 12 total miles of wrought iron left on the entire system, it is prudent to prioritize the replacement of these 12 miles and eliminate this issue from the system altogether. Most of this material (11 miles) is found in the smaller cities west and south of Kalamazoo, but there are small pockets in other areas of the state that make up the remaining mile. The Company plans to replace the wrought iron mains, and any intermingled other vintage material mains, under the Material Condition Non-Modeled Program over the next four years.

Q. Please describe the Line 1010 project in the Material Condition Non-Modeled Program.

A. The Company plans to replace sections of Line 1010, which will remove them from the TIMP cycle. Between 2021 and 2026, various segments of Line 1010, a line that was purchased from another utility, will be replaced or retired due to incomplete pressure test documentation to establish a traceable, verifiable, and complete ("TVC") record. The various projects will retire approximately 79,000 feet of existing main. The Company plans to install approximately 21,200 feet of new 8" S-HP main. The Company will also convert three services from high pressure to medium pressure. Additionally, the Company will install a 200-foot bypass near the Coolidge City Gate. The projected total cost to replace/retire the Line 1010 pipeline is $22,000,000, with $2,500,000 projected for 2024 and $9,000,000 projected for 2025. Any new main installed as part of this project section will not operate at a pressure that creates a hoop stress greater than 20% of the specified minimum yield strength of the pipe, meaning it will not need to be inspected every six years as part of TIMP. The decision to replace the pipeline was made after exploring the option to repressure test the existing pipeline. A cost and risk analysis was completed and it was found that it was not feasible to retest all of Line 1010 while serving the customers on the system. There is a level of impracticality and risk that is not reflected in the cost estimate for re-testing a distribution line of this length, especially when it comes to the customer meter stands. To test a segment, it is necessary to isolate each meter, and for high pressure ("HP") customers, each HP regulator stand. These customers would be without gas for the duration of the test prep, the actual test, and the reinstatement of that section of pipe. Test durations could vary from several hours to several days based on multiple factors including the length of pipe being tested and the type of testing required. Additionally, the testing would have to be performed in rolling segments, which would require additional work to be able to isolate individual test segments.

Q. Please describe the Material Condition Commercial/Industrial Meters Program.

A. The Material Condition Commercial/Industrial Meters Program includes the replacement of several commercial and industrial meter stands due to corrosion of the stand, obsolete regulation equipment, or excessive maintenance requirements. Replacement of obsolete equipment that the Company can no longer acquire parts for is prudent to ensure reliability for these large customers. Replacement of the stands that have excessive corrosion developing or excessive maintenance requirements is reasonable for both safety and reliability for that customer. These replacements are prioritized each year through collaboration between the Gas Commercial and Industrial Service team within Gas Operations, and the Metering and Regulation Engineering team within Gas Asset Management.

Q. Can you please explain the expenditures in the Material Condition Commercial/ Industrial Meters Program?

A. In 2022, the Company worked to resolve an issue with liquids in the gas supply at a customer's generation facility. Supply chain issues prevented the completion of the project in 2022, which moved the project completion into 2023. The 2022 capital expenditures of $1,363,000 for this program were devoted entirely to this project. In 2023, an additional $1,863,000 was spent to complete the project in addition to the replacement of four meter stands for other customers. The projection is to replace four stands in 2024 and eight additional in 2025. The Company's capital expenditures for this program were $1,363,000 in 2022 and are projected to be $3,000,000 for 2023; $503,000 for the nine months ending September 30, 2024; and $1,966,000 for the test year 12 months ending September 30, 2025, respectively. The costs for the Material Condition Commercial/Industrial Meters Program are set forth on Exhibit A-96 (KAP-4), line 5.

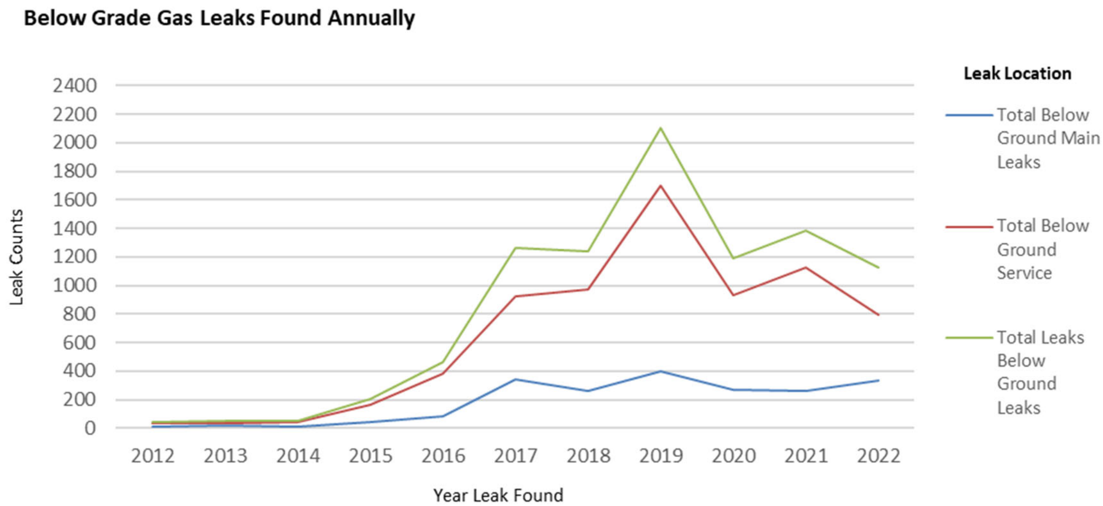
Q. Can you explain the purpose of the Material Condition Renewals Program?

A. The Material Condition Renewals Program expenditures are part of a Company initiative to reduce actionable leaks through full-service replacement versus repair or reclassification of leaks. The distinction between the Material Condition Non-Modeled Program and the Material Condition Renewals Program is that the decision to renew the facility is done by field personnel on an immediate, emergent basis in the Material Condition Renewals Program. The program orders are created and completed in the field, are not contained within the Non-Modeled program database, and are directly related to active gas leaks on gas main and/or services. The capital expenditures for the Material Condition Renewals Program were $23,331,000 in 2022 and are projected to be $29,784,000 for 2023; $18,363,000 for the nine months ending September 30, 2024; and $30,446,000 for the test year 12 months ending September 30, 2025, respectively. The historical and projected expenditures are detailed on Exhibit A-96 (KAP-4), line 3.

Q. Can you please explain the expenditures in the Material Condition Renewals Program?

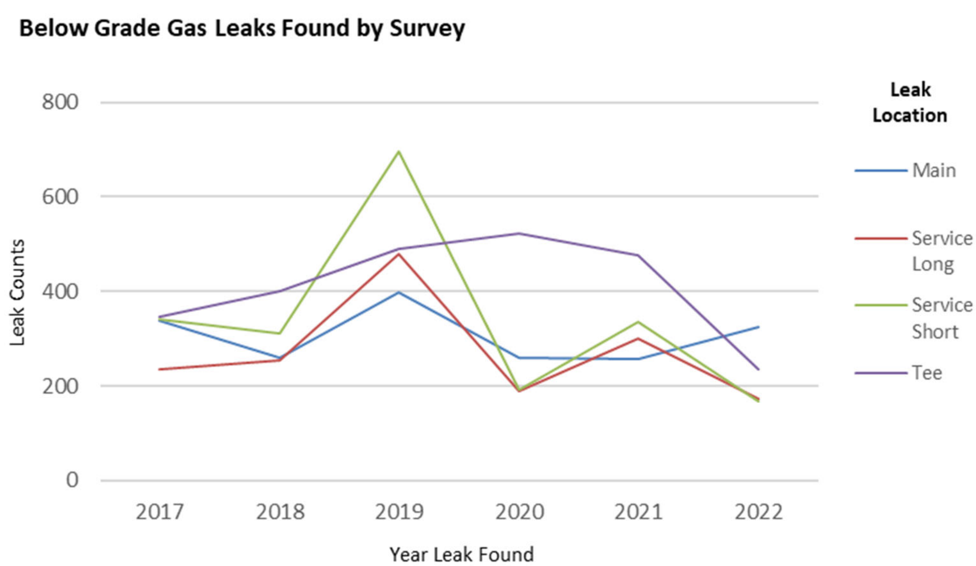
A. The Company has focused on many initiatives to reduce actionable leaks over the past few years. The graph below shows the below-grade leaks found from 2012 through 2022.

Figure 2: Below Grade Leaks Found 2012 – 2022



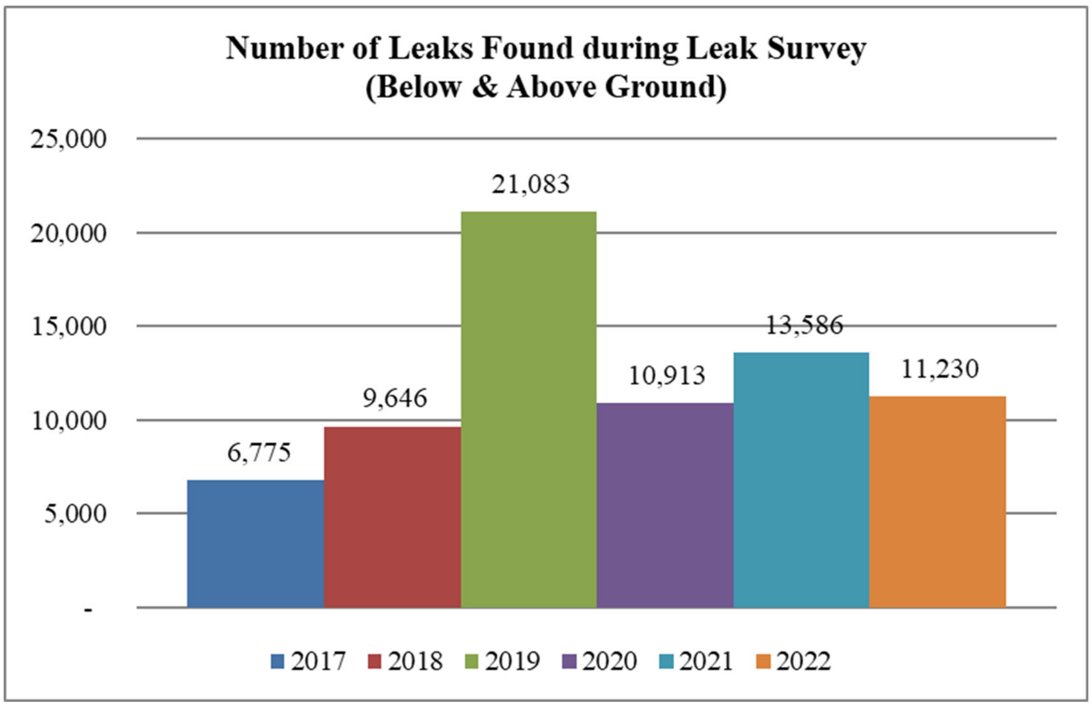
The majority of new leaks are found during Leak Survey. Each year different sections of the system are inspected, which drives fluctuations in the number of leaks found annually. Figure 3 below shows the breakdown of below grade leaks found on survey by location through 2022.

Figure 3: Below Grade Leaks Found by Survey



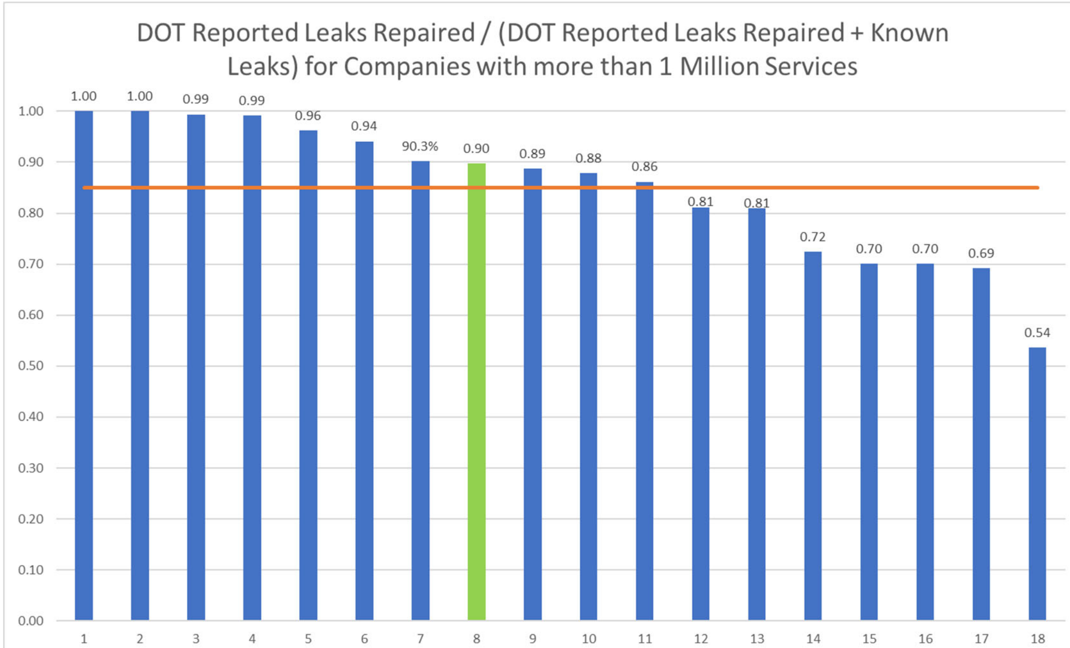
This demonstrates there is more work to be done on vintage facility replacement before a long-term, sustainable reduction in leaks is observed. As shown in Figure 4, the Company has also observed an increase in the number of leaks found by annual survey since 2017. In 2017, 6,775 leaks were found, compared to 9,646; 21,083; 10,913; 13,586; and 11,230 in 2018, 2019, 2020, 2021, and 2022, respectively. As of August 2023, the number of leaks found year-to-date is 5,894 and is on pace with the numbers seen in 2018.

Figure 4: Total Number of Leaks Found During Leak Survey



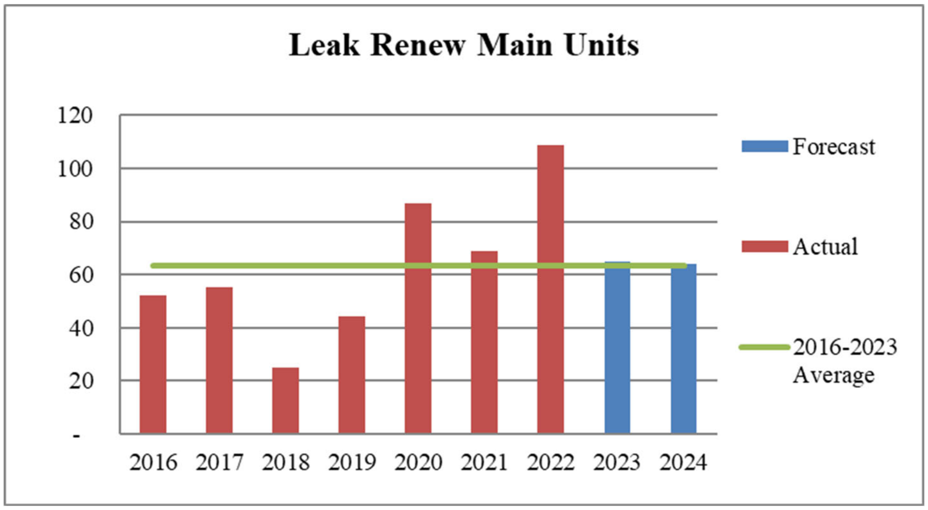
Additionally, Figure 5 below depicts a comparison of the percentage of leaks repaired for similarly sized gas companies, those with more than 1 million customers, and is based on the annual Federal DOT report information. This graph depicts the ratio of leaks repaired to the sum of leaks repaired and open leaks at year end for companies with vintage main as part of their system.

Figure 5: Industry Comparison of Leaks Repaired to Total Leaks



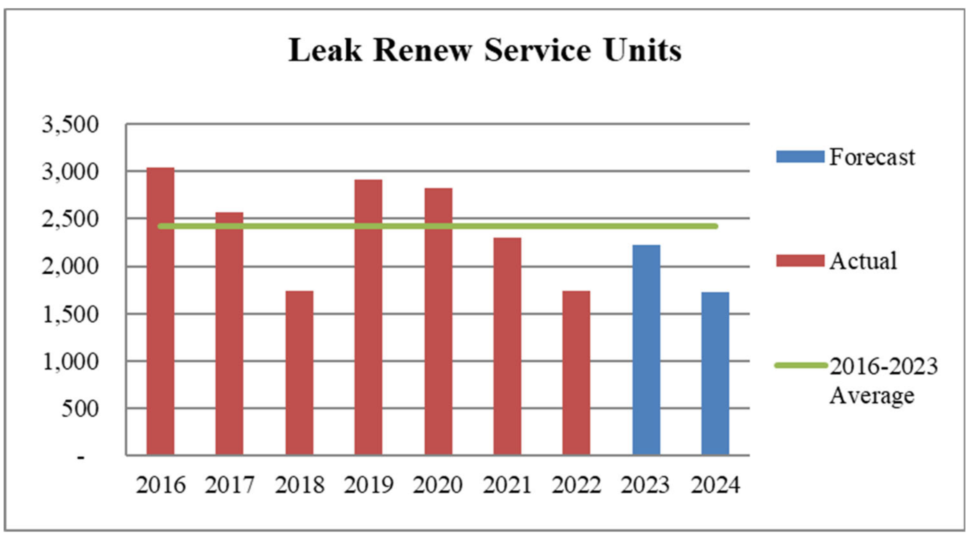
Consumers Energy is depicted in green (column 8) and was at 90.3% as of December 2022, which is above the industry average of 85%. The Company will continue to replace leaking metallic services and mains rather than repair them, which avoids the potential for future leaks on that same service or main. This replacement work will reduce the number of leaks being managed by the Company at any given point in time, as well as eliminate the possibility for a return trip to repair a service or main that has already leaked (at least) once in the past. Figures 6, 7, and 8 below demonstrate the historical and projected unit counts for gas main, service, and meter stand replacements under the Material Condition Renewals Program.

Figure 6: Gas Main Renewal Projects



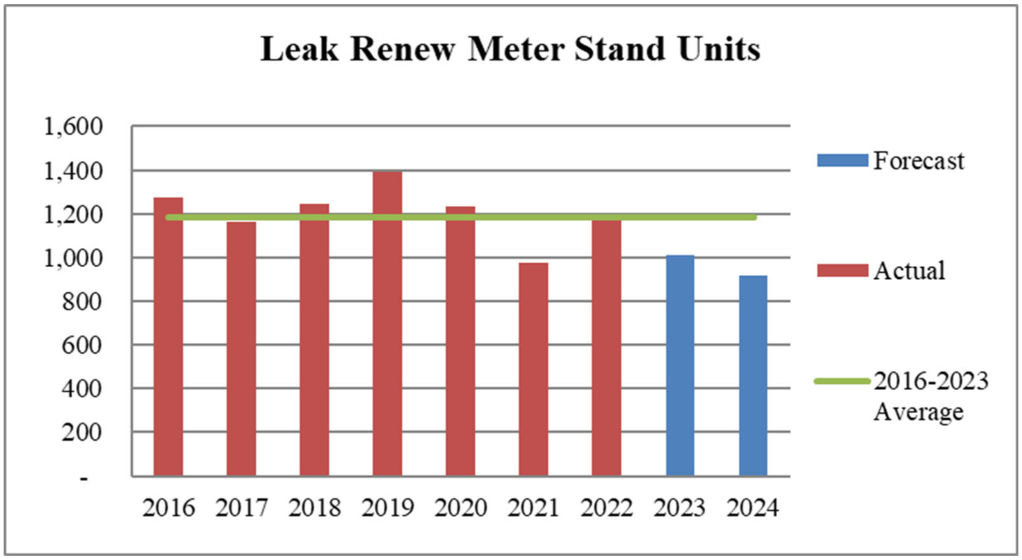
Leak Renew Main	2016	2017	2018	2019	2020	2021	2022	2023	2024
Actual	52	55	25	44	87	69	109		
Forecast								65	64

Figure 7: Gas Service Renewal Projects



Leak Renew Service	2016	2017	2018	2019	2020	2021	2022	2023	2024
Actual	3,043	2,571	1,740	2,918	2,824	2,302	1,732		
Forecast								2,218	1,721

Figure 8: Gas Meter Stand Renewal Projects



Leak Renew Mtr/Stand	2016	2017	2018	2019	2020	2021	2022	2023	2024
Actual	1,274	1,163	1,246	1,393	1,231	974	1,195		
Forecast								1,012	916

This program also contains funding to replace obsolete regulated meter stands. As described in the Customer Metering section of the NGDP, the Company received notification in 2020 that our sole sourced Regulated Meter ("RM") residential gas meter was being discontinued. This meter style is the most prevalent meter on our gas system. As the Company's remaining RM inventory reduces, meter stand replacements will be necessary to convert RM meter stands to an industry standard meter stand, with a temperature compensated top connect gas meter and separate pressure regulator. As described in the NGDP, the two types of meters have different connection methods, which require an RM meter stand to be rebuilt to accept a top connect meter. To meet meter exchange requirements and reduce extended customer outage risks related to emergent meter exchanges, the Company will continue to convert meter stands in 2023. The projected cost of $4.87 million includes 10,000 units of single meter stand rebuilds at $3.65 million and 2,000 units of multiple meter set rebuilds at $1.22 million.

Lastly, the Company is also reviewing a PHMSA Notice of Proposed Rule Making ("NPRM") issued on May 4, 2023, titled Gas Pipeline Leak Detection and Repair[1]. The publication outlines proposed revisions to numerous rules in the Minimum Federal Safety Standards for Pipelines, including Rule 192.723 and Rule 192.763 requirements for advanced leak detection equipment, enhanced leak detection practices, increased leak survey frequency, and defined repair timing for all leaks, which could increase spending in the future. The timing, if approved, of the new rule is anticipated in September 2024, with compliance by March 2025, which would fall within the test year for this case.

Q. What impact does the NGDP have on the Material Condition Renewals Program?

A. As outlined above, the Company is targeting the replacement of leaking facilities through the Material Condition Renewals Program to ensure a safe and reliable gas system. These efforts, combined with the planned replacement of vintage facilities through the NGDP, Asset Relocation – Civic Improvement, and other Material Condition programs will result in a reduction in the number of leaks on the Company's system, leading to a reduction of methane emissions and an improvement to public safety. Replacing these facilities when responding to the leak that has occurred prevents a return trip for future additional leaks on the same vintage facility and works in conjunction with the goals of the NGDP to eliminate vintage materials. Facilities replaced under the Material Condition Renewals Program will not need to be replaced again through the EIRP or VSR Program. As stated above, in relation to other programs, the Company needs to achieve a sufficient level of replacement

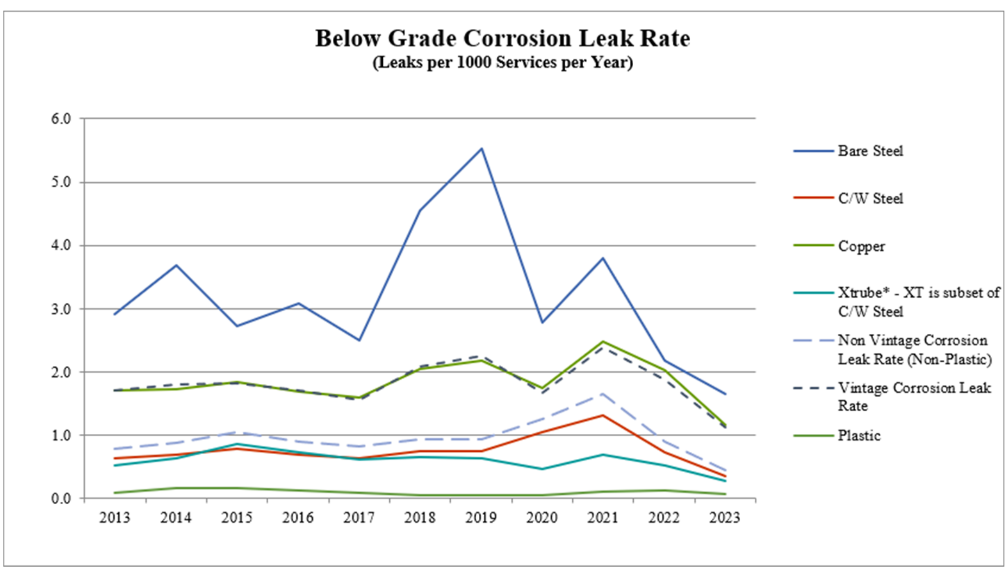
[1] PHMSA NPRM on Gas Pipeline Leak Detection and Repair publication: https://www.phmsa.dot.gov/sites/phmsa.dot.gov/files/2023-05/Gas%20Pipeline%20Leak%20Detection%20and%20Repair%20NPRM%20-%20May%202023.pdf

before the number of leaks found is expected to decrease. As more vintage facilities are replaced, the Company expects to be able to reduce expenditures in the Material Condition Renewals Program as well.

Q. Please describe the VSR Program.

A. The VSR Program began in 2017 and is a comprehensive approach to replacing all the Company's copper and bare steel vintage service materials, along with services for which the material type is unknown. The Company's goal is to programmatically replace all these service pipe types not replaced under the EIRP Distribution, Material Condition Renewals, Material Condition Non-Modeled, and Asset Relocation programs. These vintage service materials have a higher corrosion leak rate than current materials. Copper services make up approximately 85.5% of all vintage services. Figure 9 below demonstrates the corrosion leak rate on bare steel and copper services, compared to that of coated and wrapped steel and Xtrube steel services, as well as the average leak rate for vintage and non-vintage services:

Figure 9: Below Grade Corrosion Leak Rate (As of 9/1/2023)



Q. Should the duration of the VSR Program be aligned with the timeline of the EIRP?

A. The Company has reviewed the vintage service leak information and believes that there are operational advantages to aligning the VSR Program timeline with the EIRP. Aligning the overall program duration with the EIRP also allows the Company to exclude any services that are on a vintage (EIRP-type) gas main in the proactive VSR Program, because those services will be replaced when the EIRP replaces the gas main. To prioritize replacement within this timeframe, the Company will target those services outlined below with the highest potential for future leaks. The Company will continue to monitor leak, age, and soil information and will adjust future vintage service replacement plans if the data demonstrates additional trends.

The VSR Program classifies vintage services into four categories- “In-Grid VSR,” “Proactive In-Grid VSR,” “Proactive Out-of-Grid VSR,” and “Other Programs.” When a vintage service is connected to a vintage EIRP main gas distribution pipe that is being replaced, and construction crews working on the EIRP project upgrade the service(s) along with the main, the program classifies these services as In-Grid VSRs. The VSR Program proactively replaces vintage services that are not included as part of a gas distribution main pipe replacement. When these vintage material services are replaced within an EIRP project geographic footprint, they are known as Proactive-In Grid VSRs. When these vintage material services are located outside of the planned geographic footprint of an EIRP project and the service replacement is not completed with a gas distribution main pipe replacement, they are known as Proactive Out-of-Grid VSRs. Vintage services are also replaced through other programs, including Material Condition Renewals, Material

Condition Non-Modeled, Asset Relocation programs, and others. These vintage service replacements are classified as Other Programs.

Q. How does the Company determine the order in which proactive vintage services will be replaced?

A. Risk and location are the primary factors that determine prioritization. For VSRs selected through 2024, the Company used a manual analysis process that examines the leak rate along with other factors such as soil conditions and material age, of each distribution service material to prioritize replacement in accordance with the Company's DIMP. For 2025 VSRs, the Company will transition from the manual process to running the analysis in the Distribution Risk Analysis Model ("DRAM"). The DRAM was implemented in 2019, and is used primarily to analyze distribution pipelines, which supports the identification of EIRP projects. The Company has gained enough experience using the DRAM to apply the model to services as well. This aligns our approach to an industry standard model and will create efficiency within our engineering team.

Q. Does the approach for prioritizing EIRP work impact the selection process for vintage services?

A. The EIRP approach plans for the replacement of all vintage services within the EIRP project's geographic footprint, allowing the Company to gain efficiency in the field. This approach enables the Company to eliminate all vintage distribution facilities in the project footprint in one trip, which reduces impacts to customers and municipalities. However, not all vintage services fall within an EIRP project where there is vintage main, and thus the Company still requires a risk-based selection process to prioritize these services.

For 2024 and 2025, the Company plans to replace 5,182 and 6,908 total vintage services, respectively. A breakdown of these services is described below.

- In-Grid: The Company's forecast includes the replacement of 2,258 vintage services in 2024 and 2,244 vintage services in 2025 from In-Grid as part of the EIRP project work. The costs of these VSRs will be charged to the EIRP Program.
- Proactive In-Grid: The Company will also proactively replace vintage services within the projects targeted by the EIRP that are not connected to a vintage main pipeline. These projects will be selected for replacement based on the risk associated with the gas main in that area, but once a project is selected, all vintage facilities in that area will be replaced. For 2024 and 2025, the Company expects the selected EIRP projects to contain approximately 1,994 and 1,400 proactive vintage services, respectively. As these services are not connected to a vintage main, the costs for these VSRs will be charged to the VSR Program.
- Proactive Out-of-Grid: For 2024 and 2025, there are a total of 430 and 2,764 vintage services, respectively, that do not fall within an EIRP project, and therefore would not be prioritized in the EIRP. The costs for these VSRs will be charged to the VSR Program.
- Other Programs: For 2024 and 2025, the Company is forecasting 500 vintage service replacements each year from Other Programs.

Q. How many services will be replaced under the VSR Program?

A. To date, the Company has removed approximately 65,000 vintage services. At the start of 2023 there were 116,691 vintage services remaining on the Consumers Energy gas system. Table 6 below outlines the actual vintage services replacement figures as well as the projections for 2023, 2024, and 2025, including the test year.

The Company will continue to replace vintage services as part of EIRP Distribution, Material Condition Renewals, Material Condition Non-Modeled, and Asset Relocation programs. This combined approach will continue to eliminate the highest risk services on the Company's distribution system, which increases safety for customers and the public. Additionally, eliminating the highest risk vintage services will reduce the number of future gas leaks on those services and reduce greenhouse gas emissions. This approach is consistent with the Company's DIMP plan, and per that plan, will be monitored regularly for effectiveness.

Table 6: Vintage Services Replacements

	Actual 2017	Actual 2018	Actual 2019	Actual 2020	Actual 2021	Actual 2022	Projected 2023	Projected 2024	Projected 2025	Projected 12 Mos Ending 9/30/2025
VSR Program Units	6,307	9,381	5,571	5,456	5,056	2,176	1,519	2,424	4,164	3,729
VSR Unit Cost	$5,322	$6,037	$7,260	$7,848	$6,518	$7,888	$8,151	$7,496	$7,501	$7,642
VSR Program Spend ($000)	$33,564	$56,634	$40,443	$42,818	$32,955	$17,165	$12,381	$18,171	$31,233	$28,496
EIRP/Other Programs	5,169	4,042	4,064	4,291	5,245	8,235	2,741	2,758	2,744	2,748
Total Services Replaced	11,476	13,423	9,635	9,747	10,301	10,411	4,260	5,182	6,908	6,477
Total Services Remaining	170,478	157,055	147,420	137,673	127,372	116,961	112,701	107,519	100,611	102,338

The capital expenditures for the VSR Program were $17,165,000 in 2022 and are projected to be $12,381,000 for 2023; $14,363,000 for the nine months ending September 30, 2024; and $28,496,000 for the test year 12 months ending September 30, 2025, respectively. The historical and projected expenditures are detailed on Exhibit A-96 (KAP-4), line 4.

Q. Does the replacement of aging pipeline facilities through the Material Condition programs have the potential to reduce emissions into the atmosphere?

A. Yes. By replacing aging materials with the potential for increased leak rates, the Company is reducing the future methane emissions into the atmosphere.

2. <u>Gas Operations Other</u>

Q. Please list the programs within Gas Operations Other capital expenditures.

A. The five programs, as shown on Exhibit A-97 (KAP-5), page 1, are:

- Routine Computer and Equipment;
- Tools;
- Land and Right of Way ("ROW");
- Compliance and Controls; and
- Geospatial Inventory and Modeling Program.

Q. Please describe the capital expenditures relating to the Gas Operations Other Program as shown on Exhibit A-12 (KAP-3), Schedule B-5.9, line 2.

A. Capital expenditures in the Gas Operations Other Program that the Company experienced in 2022; and is projecting for the year 2023; the nine months ending September 30, 2024; and the test year ending September 30, 2025, are $16,147,000; $8,372,000; $9,196,000; and $19,898,000, respectively, as set forth on Exhibit A-12 (KAP-3), Schedule B-5.9 on line 2, columns (b), (c), (d), and (f), respectively. The Gas Operations Other Program includes the following programs:

- Routine Computer and Equipment: Computer equipment includes printers, plotters, and other technical equipment. Desktop and laptop computers for existing employees are not included in this program as they are purchased through the Information Technology ("IT") department.
  - In 2022, in addition to computer equipment, this program funded two software projects totaling $5,000,000. First, was $1,078,825 for vendor software for the ECAP Program described later in my testimony. Second, was $4,000,000 for the Company's Scheduling Optimization project. The purpose of the Scheduling Optimization project was an expansion of the Work Management Scheduling, Analytics, and Reporting project to optimize how work is scheduled and executed. In 2022, the Company developed and deployed a new digital tool called "iSchedule" as a part of this effort. This digital tool uses machine learning to optimize field work schedules.
  - The Routine Computer and Equipment Program expenditures were $5,115,000 for the year 2022; and are projected to be $332,000 for 2023; $2,000 for the nine months ending September 30, 2024; and $50,000 for the test year ending September 30, 2025, as detailed on Exhibit A-97 (KAP-5), line 1.
- Tools: Tools for field employees are purchased as part of this program. The purchase of new tools will replace tools that are worn, broken, or outdated. Tools purchased due to safety issues that come up throughout the year that meet capitalization criteria are also part of this program. The program also includes ergonomic tools that will prevent or lower the risk of employee injury.
  - As described in the Material Condition Renewals Program section earlier in my testimony, the PHMSA issued NPRM – Gas Pipeline Leak Detection and Repair which proposes new Rule 192.763 to require that leak surveys be performed using advanced technology and practices consistent with the proposed Advanced Leak Detection Program ("ALDP") performance standard. The proposed new rule will

impact the leak detection tools purchased for employees when implemented, which the Company expects will occur within the test year of this case. However, since the NPRM is under review, the Company has not included additional tool costs for complying with the new rule in this case.

- The Tools program expenditures were $4,550,000 for the year 2022; and are projected to be $5,964,000 for 2023; $1,809,000 for the nine months ending September 30, 2024; and $4,555,000 for the test year ending September 30, 2025, as detailed on Exhibit A-97 (KAP-5), line 2.

- Land and ROW: This program includes costs associated with Land and ROW specialists supporting gas distribution projects. The Land and ROW program expenditures were $1,023,000 for the year 2022; and are projected to be $749,000 for 2023; $610,000 for the nine months ending September 30, 2024; and $849,000 for the test year ending September 30, 2025, as detailed on Exhibit A-97 (KAP-5), line 3.

- Compliance and Controls Projects: These investments are made up of eight projects as listed in Table 7 below. The Compliance and Controls program expenditures were $5,459,000 for the year 2022; and are projected to be $873,000 for 2023; $2,151,000 for the nine months ending September 30, 2024; and $5,142,000 for the test year ending September 30, 2025, as detailed on Exhibit A-97 (KAP-5), line 4.

- Geospatial Inventory and Modeling Program: I will further describe this program later in my testimony. The description of how the projections were developed for this program are included in the O&M section of my testimony. The Geospatial Inventory and Modeling program expenditures were $0 for the year 2022; and are projected to be $454,000 for 2023; $4,625,000 for the nine months ending September 30, 2024; and $9,302,000 for the test year ending September 30, 2025, as detailed on Exhibit A-97 (KAP-5), line 5.

Q. Please describe the capital projections for the Compliance and Controls projects.

A. These investments are made up of eight projects with the capital projections as listed in Table 7 below.

Table 7: Compliance and Controls Project Detail

	2022 Actual	2023 Projected	2024 Projected	2025 Projected
Advanced Methane Detection	$4,635,000	$0	$1,539,370	$4,771,746
Management Action Plan technology		$52,278	$100,000	$102,500
Enterprise Contractor Oversight Dashboard	$118,126	$35,942	$0	$0
Sewer/Crossbore Program Expansion		$417,000	$100,000	$0
Remote Inspection Expansion		$80,000	$0	$0
Field Compliance Corrective Action technology solutions		$37,696	$48,630	$49,846
Enterprise Corrective Action Plan - Gas	$126,333	$34,000	$125,000	$125,000
Damage Prevention and MISS DIG	$150,268	$58,536	$400,000	$0
Other	$429,176	$157,617	$0	$0
Total Compliance and Controls	**$5,458,903**	**$873,069**	**$2,313,000**	**$5,049,092**

Q. Please describe Advanced Methane Detection.

A. Consumers Energy currently conducts leak surveys with handheld instrumentation through foot patrol of gas service lines and infrastructure. These devices read methane indications in parts per million and lack geospatial and verification capabilities. AMD is the utilization of higher sensitivity instrumentation (parts per billion), that also captures information like breadcrumbing and geospatial locations of potential methane indications, through time-stamped datalogging.

Q. How will this technology improve the Company's capability to find leaks on the system?

A. This technology will enable the Company to find and prioritize the higher risk leaks to improve public safety. When used with risk-based and algorithm capabilities, it will deliver increased safety to customers while also delivering higher quality, tracking, and cost management.

Q. Please explain the benefit to the customer delivered through the AMD.

A. AMD will improve data and understanding of system risk, target higher risk areas for system improvements, and improve detection of methane. AMD will improve safety and reliability by aiding in a strategic and data driven approach to higher-risk leak identification and remediation. The use of AMD to increase the Company's knowledge through direct measurement of system conditions to prioritize projects with greatest impact on the resolution of potential safety risks and/or methane emissions will benefit customers through cost effective improvements to system safety and emission performance. Additionally, with increasing sensitivity for methane detection, the Company will have improved capabilities to detect, classify, and remediate emissions to improve public safety. AMD also supports the Company's goal of net zero methane emissions by first time quantification and identification of large volume emission locations leading to prioritized remediation.

Q. What solution is the Company implementing?

A. The Company is currently using a third-party vendor to develop its AMD capabilities. This decision was made after careful consideration of industry offerings, and peer-to-peer conversations and communications with utilities across the United States. The vendor is known as an industry leader in Ring-Down Spectroscopy and has many years of experience deploying this technology to solve gas utility problems, such as leak survey and emission quantification. This expertise will assist in the Company's deployment of AMD in a thoughtful and progressive way to lower risk and increase safety for customers.

Q. Did the Company consider other industry offerings and equipment for comparison and testing of outputs?

A. Yes, other options were evaluated for both capabilities and costs. The Company evaluated an option that it ultimately eliminated due to the cost of that solution exceeding the estimated cost to operate the selected units, which are installed in vehicles dedicated to methane detection. Another option that detects methane and ethane using a "Middle InfraRed Analyzer" instead of a "Ring-Down" sensor was not selected as it was newer to the market and there was little industry information available, particularly for large-scale implementation. The Company will periodically review the industry and market for AMD best practices and technologies.

Q. How is Consumers Energy planning on implementing this technology?

A. Consumers Energy planned a two-phased AMD implementation, with methane emission, risk modeling, and super emitter work activities planned as part of Phase 1. Phase 2 of the AMD technology implementation looks to use AMD for compliance-based leak survey, and as a result of the higher quality data, analytics and algorithms can modernize and enable risk-based leak surveys. This phase will be supported by the GCCP - SIMS Conversion project described in the Geospatial Inventory and Modeling section later in my testimony.

Q. Please explain the learnings from Phase 1.

A. The Company conducted a number of case studies during Phase 1 to learn the technology and identify areas of value beyond compliance leak survey. One case study focused on the DIMP Risk Model analysis process. Emissions data was collected and linked to pipe segments, helping with pipe identification and selection for replacement. Below are learnings from that study and others that were conducted during Phase 1.

- **Emission Quantification:** Emissions Quantification is a drive mode that is used to identify Super Emitters, or any large leak over a set flow rate threshold. Consumers Energy drove in this analytics mode and selected emissions reporting to evaluate emissions, or Super Emitters, set at a threshold of 10 SCFH or greater. In the Company's studies, it was determined that Super emitters account for only 2.82% of the incidents detected, but account for 41.4% of the total emissions.

- **Source Discrimination:** It was determined that source discriminations work with AMD devices to assist in pinpointing hard-to-locate leaks or to rule out bio-gas methane that could produce false positives through current leak survey methodologies.
- **Pre/Post Construction drives:** The Company was able to drive pre-construction collecting data to determine the emissions being released and then drive again after construction to determine whether the replacement projects reduced emissions.
- **Known Leak Prioritization:** Incorporating this data in leak repair prioritization enables the Company to see which leaks are higher emitting and prioritize those leaks. The 97 leaks analyzed in the case study were reprioritized in a way that greatly reduced methane emissions from the repairs. Using this approach eliminated 4.5 metric tons of emissions.

Q. Please explain the transition from Phase 1 to Phase 2.

A. In addition to the Phase 1 studies cited above, compliance leak survey testing was performed in parallel with current methodologies to prepare for Phase 2, and to determine differences in output and quality, while also identifying needed changes in standards and practices for future implementation. Traditional leak survey inspectors walked each location as the unit drove the same area, followed up by investigation of any suspected leaks, and then compared the data. On average, AMD found one indicator of a possible leak for every mile of distribution main investigated. In 2023, the Company entered Phase 2 to further develop AMD capabilities for performing Compliance Leak Survey. In this phase, the Company will continue to refine its detection capabilities with more parallel testing and procedure refinement through 2024 to ensure it is focusing its investigations on true gradable leaks. The new AMD application hardware and software will be complemented by current asset management, work management, and analytics platforms - including the GIS; Inspection Manager; Systems, Applications, and Products (“SAP”); Service Suite; and Distribution Risk Analysis Model.

Q. Please further explain the planned implementation for Phase 2.

A. In 2023, AMD drove sections that were due for compliance while traditional leak survey inspectors continued their normal walking survey to get a baseline. In 2024, AMD will continue to expand its scope within the compliance leak survey process as procedures continue to be refined and adjusted to scale. AMD will then be used to survey about 20% of the gas territory in 2025, and about 20% of the gas territory every year for the next four years (2026-2029). Traditional leak survey will be used for those areas not part of the AMD schedule in these years to fulfill any compliance leak survey requirements. Additionally, the Company will continue the Phase 1 emission surveys, project prioritization input, and pre/post constructions and emergency drives.

Q. How will the Company procedures be updated when a potential leak is found by AMD?

A. The Company's current processes for leak investigations and classification will remain the same. What will change is the leak identification process. The unit will drive an area three (or more) times, which is the recommended number of drives to get coverage, and the data will be sent in for analysis. At the conclusion of the final drive, the leak detection team will run reports and create a schedule for investigation. Leak indication search areas will be identified, and qualified individuals will be sent to those areas to perform a leak investigation.

Q. What costs are associated with Phase 1 testing and Phase 2 rollout?

A. Table 8 below provides the capital investment and O&M expenses for the AMD Program. The 2021 actuals and 2022 actual and projected amounts were for Phase 1 testing. The 2023 and 2024 capital costs are associated with the purchase of one additional unit in 2024.

As the Company expands Phase 2 to statewide leak survey, the Company anticipates the need for three additional units in 2025 as well. The O&M expenses will continue to be license fees and costs associated with performing compliance leak survey, emissions studies, and other activities. Effective September 1, 2023, the AMD team was integrated into the Gas Regulatory and Compliance department described above from the Gas Operations Compliance and Controls department. The projected O&M expenses for September through December 2023, 2024, and 2025 are included in Exhibit A-95 (KAP-2), page 3, line 9.

Table 8: AMD Actual and Projected Costs

	2021	2022	2023	2024	2025	Total
O&M	$ 122,874	$ 102,706	$232,834	$ 199,596	$ 432,834	$ 1,090,844
Capital	$2,400,000	$4,635,000	$ -	$1,539,370	$4,771,746	$13,346,116

Q. Is the Company expecting to see an increase in leaks and associated leak repairs using this new technology?

A. The technology is more sensitive and can detect smaller amounts of gas release than traditional tools. As a result, the Company is expecting that as it deploys this technology for its compliance leak survey, indicators of possible leaks will be detected three times more often than previously detected for the first few cycles based on thresholds set on the unit for reporting.

Q. Does Consumers Energy's AMD deployment support any regulatory requirements not already discussed?

A. Yes. The PHMSA Advisory Bulletin 2021-0050 requires pipeline facility operators to update their inspection and maintenance plans to address the elimination of hazardous leaks and minimization of releases of natural gas. Additionally, as described in the Material

Condition Renewals Program section earlier in my testimony, the PHMSA issued NPRM – Gas Pipeline Leak Detection and Repair which proposed new Rule 192.763 to require that leak surveys be performed using advanced technology and practices consistent with the proposed Advanced Leak Detection Program ("ALDP") performance standard. The Company is currently reviewing the proposed new rule and expects it to be issued within the test year of this case. The Company has built its AMD Program to further its leak and methane detecting capabilities in accordance with this and other laws, codes, and guidelines.

Q. Please describe how the implementation of AMD impacts Consumers Energy's stated goals in the NGDP.

A. AMD is described in the NGDP under the digital capabilities and supports the Company's stated goal to provide a safe, affordable, reliable, and clean natural gas system for Michigan. The implementation of this technology also supports the Company's GSMS as it is part of the recommended practice to evaluate new platforms that can further enhance the Company's capabilities in alignment with API RP 1173, which provides, "11.2 – *Management shall also periodically evaluate new technology that may enhance pipeline safety*."

Q. Please describe the Enterprise Corrective Action Program.

A. The ECAP was initiated at Consumers Energy in 2020 as an enterprise-wide issue management and compliance program supporting safe and excellent operations. The structured platform and methodology allow for transparency in reporting issues, identifying trends, and closing compliance and safety gaps through corrective actions and controls, based upon associated risk thresholds. ECAP's functionality for managing processes and performance, as well as analyzing data, focuses risk reduction efforts, informs operational business decisions, and promotes the integrity and deliverability of the energy infrastructure. Starting in 2022, ECAP supported stakeholders in Gas Operations, Engineering, and Regulatory maintaining adherence to GSMS standards established in API RP 1173.

Q. What costs are associated with the ECAP implementation?

A. ECAP will use a phased implementation approach:

- Phase 1 (Go Live 2022) – Gas Operations, Regulatory, and Engineering;
- Phase 2 (Go Live 2023) – Electric Operations and Engineering;
- Phase 3 (Go Live 2024) – Generation Operations and Electric Supply Engineering; and
- Phase 4 (Go Live 2025) – Corporate Safety and Health (Gas, Electric, and Generation).

The actual and projected capital expenditures included in this case represent the gas portion of ECAP only.

Table 9: ECAP Actual and Projected Capital Costs

2021 Actual	$1,226,304	Vendor software to acquire licensing, service, and project support to implement ECAPs system of record into the Enterprise
2022 Actual	$1,204,618	ECAP expense was $126,333 for the closeout of Phase 1 project implementation. Additionally, $1,078,285 was expensed in the Computer and Equipment program to advance the purchase of the Environmental Health and Safety Suite of software related to Phase 4 of the project.
2023 Projected	$ 34,000	Projected expenses for ECAP platform modifications to support Phase 3
2024 Projected	$ 125,000	Projected expenses for ECAP platform modifications to support Phase 4
2025 Projected	$ 125,000	Projected expenses for ECAP project closeout

Q. Please describe the GCCP – SIMS project funding requirements within the Geospatial Inventory and Modeling Program.

A. The GCCP – SIMS project will convert and migrate the SIMS gas service asset data into the gas distribution GIS and reconfigure application and technical integrations, creating a single system of record for both gas service and distribution asset records. This program includes O&M and capital funding requirements as shown in Table 10. For the GCCP - SIMS project, the projected O&M expense is $754,555 and the capital expenditure is $480,796 for the test year 12 months ending September 30, 2025.

Table 10: GCCP - SIMS Actual and Projected Costs

GCCP-SIMS							
	2017 - 2021 Actual	2022 Actual	2023 Projected	2024 Projected	2025 Projected	Project Total	Test Year
O&M	$ 1,808,123	$ 564,000	$ 2,526,171	$ 3,134,724	$ -	$ 8,033,018	$ 754,555
Capital	$ -	$ -	$ 454,000	$ 2,939,740	$ -	$ 3,393,740	$ 480,796

The existing gas service records have no spatial data, and the database is limited in its ability to store all required service attributes, which create inaccuracies in U.S. DOT reporting, System Planning gas load analysis, and Distribution Risk Models. Tabular data is manually linked between the SIMS and the GIS, which causes incomplete and inconsistent data. Gas data must be queried from two independent systems and pieced together to get a complete picture of the distribution network, which limits the Company's ability for data analytics, creates operational complexities, adds risk to damage prevention efforts, and increases response time during safety emergencies. The existing systems use vastly different data formats and technologies for maintaining and accessing this data, therefore creating two overlapping and sometimes conflicting systems of record. The project will provide value by:

(1) Establishing a single gas distribution system of record within GIS that represents the gas distribution main and services from the customer's meter stand to the city gate;

(2) Creating an enhanced GIS connectivity model with spatial placement of gas services over an ortho-photo grid, which is essentially digital imagery of an aerial photograph;

(3) Improving the ability to identify data gaps and inconsistencies systematically;

(4) Strengthening the data required to support advanced risk analysis; and

(5) Creating the foundation required to enable future asset maintenance tools, including tools that allow the Company to track gas distribution assets, and to develop Global Positioning System leak survey routes to facilities.

Without this support, there is increased safety risk associated with the inability to provide accurate and real-time data to end users to support planned and emergent operational activities, incident response, and predictive analysis that requires more accurate data analytics to support compliance reports.

Q. Please describe the Utility Network project and its funding requirements within the Geospatial Inventory and Modeling Program.

A. The Utility Network project will transform the Company's current GIS platform to the Esri Utility Network Model, and establish a unified gas transmission, distribution, and stations data model in support of optimizing the core engineering and operational processes, technologies, and data. This project is an important part of the Company's GSMS and will support continuous improvement for data gathering processes governed by the Risk Management element of the GSMS. This program requires both capital and O&M funding as shown in Table 11. For the Utility Network project, the O&M projected expense is $1,715,258 and the projected Capital expenditure is $8,821,233 for the test year 12 months ending September 30, 2025.

Table 11: Utility Network Actual and Projected Costs

Utility Network							
	2022 Actual	2023 Projected	2024 Projected	2025 Projected	2026 Projected	Project Total	Test Year
O&M	$ -	$ -	$ 947,781	$ 1,971,084	$ 196,068	$ 3,114,933	$1,715,258
Capital	$ -	$ -	$ 2,888,200	$ 10,798,910	$ 4,593,866	$ 18,280,976	$8,821,233

The growing business requirements for advanced analytics and business challenges presented from regulatory mandates and requirements to support a strong pipeline safety management system necessitate geospatial insight on a more granular asset level than what is currently available. Managing the distribution and transmission data in different models continues to be a challenge. The Company's current GIS platform will become unsupported as Esri's product development focus is shifting to the components that support the ArcGIS Utility Network Management extension, ArcGIS Enterprise, and ArcGIS Pro. Esri's development team has taken the existing core technology of ArcMap and the geometric network for managing gas and electric networks to the limits of its capabilities and will no longer build additional functionality. Esri utility solution partners, including several currently in use at the Company, are also moving their product lines away from the geometric network and will soon only support their solutions on the Utility Network. The project adds the following value:

(1) Mitigates risks associated with product support end of life;

(2) Enables detailed asset management and location-based analytics to bring clearer understanding around the assets that support energy delivery;

(3) Enables real-time GIS with ArcGIS Event Server (via ArcGIS Enterprise);

(4) Increases productivity through use of shortcuts, templates, and streamlined workflows within the software;

(5) Provides extensive, out-of-the-box tracing tools;

(6) Provides 3D visualization functionality;

(7) Enables users with editing tools, giving them guidance at every step of the process for developing workflows and enforcing stronger data integrity;

(8) Continues to support the concept of long transactions, enabling users to create future changes to the network model that go into effect after a certain time;

(9) Offers views of the up-to-date network in a map or schematic diagram with the ability to quickly toggle back and forth between them; and

(10) Enables archiving and historical snapshots to view the state of the gas network over time.

All these capabilities will result in greater insight and efficiency that improves the safety and delivery to customers in Michigan.

Q. Please describe Exhibit A-100 (KAP-8).

A. Exhibit A-100 (KAP-8), 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 that I am sponsoring compared with the Company's most recent general gas rate case, Case No. U-21308.

Q. Can you explain why columns (c), (d), (e), and (f) of Exhibit A-100 (KAP-8) do not contain any data with the exception of the EIRP?

A. The information for column (c), the "Last Rate Case Approved Spending Plan Case No. U-21308," cannot be provided because Case No. U-21308 resulted in a settlement agreement that did not state approved capital spending amounts for the programs I am representing except for the EIRP. Thus, column (c), the "Last Approved Spending Plan" cannot be calculated for most 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. 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-21308, which was the 12 months ending September 30, 2024, is a time period that has yet to transpire as of the filing of this case.

Q. Please summarize your direct testimony.

A. My direct testimony describes the Gas Engineering and Supply O&M expenses and capital investments 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, modernize the system, and protect public safety. The Company's NGDP will work to enhance the Company's gas distribution system and offer additional opportunities for collaboration with municipal partners. Through the implementation of the NGDP and the execution of the projects outlined in my direct testimony above, 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.

S T A T E O F M I C H I G A N

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the application of	)	
CONSUMERS ENERGY COMPANY	)	
for authority to increase its rates for the	)	Case No. U-21490
distribution of natural gas and for other relief.	)	
	)	

DIRECT TESTIMONY

OF

JAMES P. PNACEK, JR.

ON BEHALF OF

CONSUMERS ENERGY COMPANY

December 2023

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 the Gas Customer Choice 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 September 30, 2025. 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-101 (JPP-1)	Summary of Actual & Projected O&M Expenses: Operations, Maintenance & Metering, Field Services, Other Operations;
Exhibit A-102 (JPP-2)	Summary of Actual & Projected O&M Expenses: Operations, Maintenance & Metering Programs;
Exhibit A-103 (JPP-3)	Summary of Actual & Projected O&M Expenses: Field Operations Services; and
Exhibit A-104 (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.

<u>GAS OPERATIONS O&M EXPENSES</u>

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. Operations Performance
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 Compliance and Controls program that was formerly part of the Gas Operations Division testimony is no longer being utilized effective month ending August 2023, and has been reorganized into other Company divisions. The portion of the Compliance and Controls program that was reorganized into the Gas Operations Division was incorporated into the existing Supervision/Admin Staff sub-programs.

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 that are 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 Gas Operations O&M 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 12 months ending September 30, 2025?

A. The Company has identified the O&M expenses for the test year 12 months ending September 30, 2025 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 $106,612,000 as shown on Exhibit A-101 (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 2022 actual and derivation of the projected test year O&M expenses for the Gas Operations expenses shown on Exhibit A-101 (JPP-1).

A. The 2022 actual O&M expense amount of $130,251,000 as shown on Exhibit A-101 (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 12 months ending September 30, 2025 were calculated using a weighted average of the 2024 and 2025 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 $106,612,000 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-102 (JPP-2), page 2; Exhibit A-103 (JPP-3), page 2; and Exhibit A-104 (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. Column (b), which is titled "Actual 12 Mos Ending Dec 31, 2022" shows the historical O&M expense. Column (c), which is titled "Base O&M for Merit and Inflation 12 Mos Ending Dec 31, 2022" 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. Therefore, column (i) represents the increase (or decrease) in O&M expenses that is not due to inflation; in other words, this represents where O&M expenses are changing due to some other factor than inflation. The projected increases from 2022 to the test year period ending September 30, 2025 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.

Operations, Maintenance, and Metering

Q. Please describe the O&M expenses related to the Operations, Maintenance, and Metering sub-programs shown on Exhibit A-102 (JPP-2).

A. The Operations, Maintenance, and Metering sub-programs includes the operation and maintenance of the Transmission and Distribution system. Major assets in this sub-program includes mains, services, pipelines, storage fields, meters, city gates, valves, and regulators. The sub-program also includes 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 are primarily focused 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 $1,997,000 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 3,193 bi-monthly reads at rectifiers and designated bond points. The annual test point reads by Headquarters for this sub-program is summarized in the following table:

Table 1

2024 Annual Reads Per Headquarters	
Work Headquarters	**Annual Read at Designated Test Points Complete 100% of These Reads Impacts Year 2025**
Adrian	429
Alma	945
Bad Axe	617
Bay City	1,996
Cadillac	94
Flint	4,910
Greenville	606
Groveland	2,715
Hastings	575
Howell	1061
Jackson	1,686
Kalamazoo	3,375
Lansing	3,795
Livonia	6258
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 49,000 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 3,193 bi-monthly reads at rectifiers and designated bond points. The overall number of reads has reduced as the Company installs remote monitoring units ("RMUs") which 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 is summarized in the following table:

Table 2

2024 Bi-monthly Reads (Includes Rectifiers and Bond Points)							
Work Headquarters	**Jan**	**Mar**	**May**	**Jul**	**Sep**	**Nov**	**Total**
Adrian	1	13	1	1	1	1	
Alma	18	41	18	18	18	18	
Bad Axe	6	14	6	6	6	6	
Bay City	5	41	5	5	5	5	
Cadillac	3	10	3	3	3	3	
Flint	84	87	84	84	84	84	
Greenville	11	15	11	11	11	11	
Groveland	14	79	14	14	14	14	
Hastings	13	27	13	13	13	13	
Howell	1	33	1	1	1	1	
Jackson	18	64	18	18	18	18	
Kalamazoo	89	164	89	89	89	89	
Lansing	67	88	67	67	67	67	
Livonia	11	68	11	11	11	11	
Macomb	7	38	7	7	7	7	
Marshall	7	16	7	7	7	7	
Midland	6	31	6	6	6	6	
Owosso	2	29	2	2	2	2	
Royal Oak	25	89	25	25	25	25	
Saginaw	51	51	51	51	51	51	
Total	**439**	**998**	**439**	**439**	**439**		**3,193**

In addition to the annual reads, the O&M expenses include dollars to complete three-year atmospheric above grade inspections at 2,103 locations in 2025. This includes zero bridge inspections. The atmospheric above grade and bridge inspection by Headquarters for this sub-program is summarized in the following table:

Table 3

2024 – 3 Year Inspections Including Contractor Bridge Inspections			
Work Headquarters	**Atmospheric Aboveground Corrosion Inspection (every 3 years) Impacts 2025**	**3 Year Bridge Inspections Impacts 2025**	**Total**
Adrian	22	0	22
Alma	35	0	35
Bad Axe	35	0	35
Bay City	103	0	103
Cadillac	6	0	6
Flint	194	0	194
Greenville	25	0	25
Groveland	62	0	62
Hastings	30	0	30
Howell	47	0	47
Jackson	142	0	142
Kalamazoo	231	0	231
Lansing	204	0	204
Livonia	128	0	128
Macomb	263	0	263
Marshall	20	0	20
Midland	38	0	38
Owosso	61	0	61
Royal Oak	233	0	233
Saginaw	224	0	224
Total	**2,103**	**0**	**2,103**

For the test year, the Company will have approximately 10 bridge locations to complete repairs based upon its 2023 bridge inspection results. The Company will not have any three-year atmospheric above ground inspections during the test year, as it plans to have the 2024 inspections completed by September 2024.

It is anticipated 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 2022 and 2023 Downed Sectors	
2022	**2023**
2,158 downed sectors	2,217 downed sectors

In addition to the annual reads, inspections, and diagnosis work, the O&M expenses also include dollars to complete approximately 600 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 includes 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	**2022 Actual**	**Test Year**
Distribution Cathodic Protection – Non WBS	$241,499	$244,887
Cathodic Protection – Contractor; Material and Other Expenses	$528,196	$227,009
Cathodic Repairs	$207,420	$215,102
Sector Diagnosis	$265,679	$234,232
Annual Pipe to Soil Survey	$1,146,006	$799,252
Riser Wraps – Non-Leak Maintenance	$46,224	$49,106
Bi-Monthly Survey	$242,540	$227,411
Total Program	**$2,677,564**	**$1,997,000**

Q. What is the basis for determining the $1,997,000 of projected O&M expenses in the test year 12 months ending September 30, 2025 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 Projected	34,387	8,920	$2,269,486
2024 Projected	41,750	8,734	$1,993,000
Projected 12-Mos Ending Sep 30, 2025	41,750	8,734	$1,997,000

The Company's projection for Distribution Cathodic Protection test year spending is based on a weighted average of the 2024 (20%) and 2025 (80%) forecast amounts, which reflects the Company's historical experience of program expense timing.

<u>Pipeline – Distribution</u>

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 $6,931,000.

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 gas mains and services, including new business branch services and meter and service relocations (where the entire service from the main to the meter is not installed or replaced). 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, non-leaking maintenance activities such as repairing or replacing lockwing valves to allow emergency shut-offs, installing meter protection bollards, lowering facilities if grade has changed, installing drips on the standard (low) pressure system to allow the water to be pumped out of the drip 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 that 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. The electric usage utility costs for gas distribution regulation facilities and inspections at the Huron Compressor Station are also 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	**2022 Actual**	**Test Year**
Material Condition Emergent	$929,610	$600,017
Material Condition	$4,318,096	$2,787,114
Huron Compressor Station	$138,571	$89,441
Main & Services Alterations	$2,210,852	$1,426,994
Property Restoration	$1,232,645	$795,610
Site Checks	$268,695	$173,429
Pre-fabrication Costs	$877,965	$566,682
Other including utilities	$554,855	$491,712
Total Program	**$10,531,290**	**$6,931,000**

Q. What is the basis for determining the $6,931,000 of projected O&M expenses in the test year 12 months ending September 30, 2025, for this sub-program?

A. Projected test year spending reductions are driven by project work reducing the number of non-leak maintenance orders, aligning customer requested workorders and managing third-party contractor costs such as temporary traffic control and hydrovac. The 2023 and 2024 projections anticipate reduced levels of workload completion, efficiencies, and increased labor rates. This historical and projected activity in this sub-program is summarized in the following table:

Table 8

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 Projected	6,336	28,413	$7,132,903
2024 Projected	6,173	27,610	$6,931,000
Projected 12-Mos Ending Sep 30, 2025	6,173	27,610	$6,931,000

The Company's projection for the Operations and Maintenance Pipeline – Distribution sub-program test year spending is a weighted average of the 2024 (23%) and 2025 (77%) forecast amounts, which reflect the Company's historical experience of program expense timing.

<u>Pipeline – Transmission</u>

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 $3,165,218.

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 9

Operation & Maintenance – Pipeline- Transmission Projection Breakdown by Activity Type		
Work Type	**2022 Actual**	**Test Year**
Non WBS	$1,119,088	$549,504
Contractor; Materials, Credits and Other Expenses	$336,987	$321,858
Code Inspections	$892,032	$637,534
Preventive Maintenance & Operations	$286,134	$300,120
Demand Maintenance	$604,432	$416,296
Facilities Locating for Third Parties (PA 174))	$983,300	$939,905
Total Program	**$4,221,974**	**$3,165,218**

Q. What is the basis for determining the $3,165,218 of projected O&M expenses in the test year 12 months ending September 30, 2025, 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 2024 (28%) and 2025 (72%) 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 units 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. Ticket volumes are trending 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 2022 and the current economic growth, ticket volumes and hours are expected to be flat through 2025 (see below table).

Table 10

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
Trend 2023	9,500	8,000
Trend 2024	9,500	8,000
Trend 2025	9,500	8,000

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

Table 11

Transmission				
	Standard Labor Rates	**Indirect Labor Rates**	**Vehicle Rates**	**Total Rate**
2022	$66.51	$30.59	$49.22	$146.32
2023	$69.18	$24.90	$36.67	$130.75
2024	$72.53	$25.39	$38.44	$136.36
2025	$75.33	$26.37	$39.92	$141.62

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

Table 12

Operations–& Maintenance - Pipeline Units/Orders, Hours & Dollars			
Year (Jan-Dec)	**Units/Orders**	**Hours**	**Dollars**
2016	12,937	24,033	$2,675,390
2017	15,865	21,865	$2,131,709
2018	20,056	23,556	$2,670,236
2019	20,242	26,639	$3,121,709
2020	19,896	23,634	$3,012,604
2021	17,395	20,676	$3,198,861
2022	12,007	21,783	$4,221,974
2023 Projected	12,007	17,316	$3,455,217
2024 Projected	12,007	16,823	$3,165,218

Projected 12-Mos Ending Sep 30, 2025	12,007	16,823	$3,165,218

<u>Regulation Distribution</u>

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 $7,728,000 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
- 1638 1-inch and larger high-pressure regulation stands
- 96 Odorant Injection Facilities
- 6135 Designated Pipeline Valves

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

Table 13

Operation & Maintenance – Regulation Distribution Projection Breakdown by Activity Type		
	2022 Actual	**Test Year**
Designated Valves	$1,563,541	$1,527,569
Regulation Inspection	$4,351,936	$3,220,211
Regulation Repairs	$2,689,976	$2,628,087
Vegetation Management	$521,487	$352,133
Total Program	$9,126,940	$7,728,000

Q. What is the basis for determining the $7,728,000 projected O&M expenses in the test year 12 months ending September 30, 2025 for this sub-program?

A. In order 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 14

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 Projected	10,018	42,702	$7,736,317
2024 Projected	12,022	43,061	$7,728,000
Projected 12-Mos Ending Sep 30, 2025	12,022	43,061	$7,728,000

The projection for the 12 months ended September 30, 2025 is a weighted average of the forecasts for 2024 (26%) and 2025 (74%), which reflects the Company's recent historical experience with the timing of program expenses.

<u>Measurement and Regulation Transmission</u>

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"), Pipeline and Hazardous Materials Safety Administration ("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 15

Operation & Maintenance – Transmission Measurement & Regulation Projection Breakdown by Activity Type		
Work Type	**2022 Actual**	**Test Year**
Non WBS	$630,318	$305,910
Contractor; Materials, Credits and Other Expenses	$919,209	$758,937
Demand Maintenance	$1,001,378	$767,005
Preventative Maintenance	$1,006,558	$885,908
Inspections	$596,641	$508,132
Third Party Contracts	$185,202	$159,973
Total Program	$4,339,305	$3,385,865

Q. What is the basis for determining the $3,385,865 of projected O&M expenses in the test year 12 months ending September 30, 2025, for this program?

A. The test year amount of $3,385,865 is a weighted average of the 2024 (31%) and 2025 (69%) 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 17,022 hours during the test year in this proceeding.

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

Table 16

Transmission				
	Standard Labor Rates	Indirect Labor Rates	Vehicle Rates	Total Rate
2022	$66.51	$30.59	$49.22	$146.32
2023	$69.18	$24.90	$36.67	$130.75
2024	$72.53	$25.39	$38.44	$136.36
2025	$75.33	$26.37	$39.92	$141.62

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

Table 17

Operations & Maintenance – Measurement & Regulation Transmission Units/Orders, Hours & Dollars			
Year (Jan-Dec)	Units/Orders	Hours	Dollars
2016	5,294	18,233	$4,609,086
2017	5,313	20,497	$3,461,000
2018	5,331	20,497	$3,074,000
2019	5,450	20,722	$3,005,000
2020	5,192	18,540	$2,897,776
2021	5,028	17,795	$3,188,919
2022	5,908	17,197	$4,339,305
2023 Projected	5,324	16,320	$3,562,000
2024 Projected	6,006	17,022	$3,385,865
Projected 12-Mos Ending Sep 30, 2025	6,082	17,022	$3,385,865

<u>**Odor Response**</u>

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 18

Odor Response Projection Breakdown by Activity Type		
Work Type	**2022 Actual**	**Test Year**
Odor Response	$6,445,130	$6,286,000
Total Program	**$6,445,130**	**$6,286,000**

Q. What is the basis for determining the $6,286,000 of projected O&M expenses in the test year 12 months ending September 30, 2025, for this sub-program?

A. The Company has projected the costs of the Odor Response sub-program based on expected workload associated with 40,708 odor response orders.

Each odor response call is expected to require gas service worker jobsite time of 0.74 hours, or about 44 minutes. This expected time requirement is based on reviews during 2022 and 2023 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 19

Service				
	Standard Labor Rates	**Indirect Labor Rates**	**Vehicle Rates**	**Total Rate**
2022	$68.09	$93.28	$27.92	$189.29
2023	$70.23	$105.35	$25.99	$201.56
2024	$73.80	$103.32	$29.52	$206.64
2025	$76.63	$107.28	$30.65	$214.56

However, the decrease in units from 2022 (44,729) to the test year (40,708) will help offset the labor increase. The projected test year dollars are less than the 2022 historical actual expense.

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

Table 20

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 Projected	40,292	30,567	$6,183,000
2024 Projected	40,708	30,124	$6,286,000
Projected 12-Mos Ending Sep 30, 2025	40,708	30,124	$6,286,000

The projection for the 12-month ending September 30, 2025, is a weighted average of the 2024 (28%) and 2025 (72%) 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 21

Leak Repair and Survey Projection Breakdown by Activity Type		
Work Type	**2022 Actual**	**Test Year**
Leak Survey	$4,372,645	$3,820,211
Leak Classification	$2,407,107	$1,388,094
Leak Assessments	$791,243	$456,282
Leak Repairs – Meter Stands and Regs	$5,026,589	$2,898,658
Leak Repairs – Services	$2,376,288	$1,370,322
Leak Repair – Mains	$3,967,922	$2,288,161
Total Program	**$18,941,796**	**$12,221,729**

Q. What is the basis for determining the $12,221,729 of projected O&M expenses in the test year 12 months ending September 30, 2025 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, and leaks requiring repair. 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; and
- Discretionary leak surveys - Performed on an as needed basis.

The Leak Surveys for the test year is forecasted higher than the previous two years with approximately 366,500 units. This is based on the code-required schedule and frequency of the gas facilities to be surveyed. In 2017, 6,775 leaks were found, compared to 9,646 in 2018; 21,083 in 2019; 11,431 in 2020; 13,586 in 2021; and 11,230 in 2022. 2023 year-end projection for leak surveys is 12,129. The increase in leaks found 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 the Figure 1 with the data provided in Table 22.

Figure 1

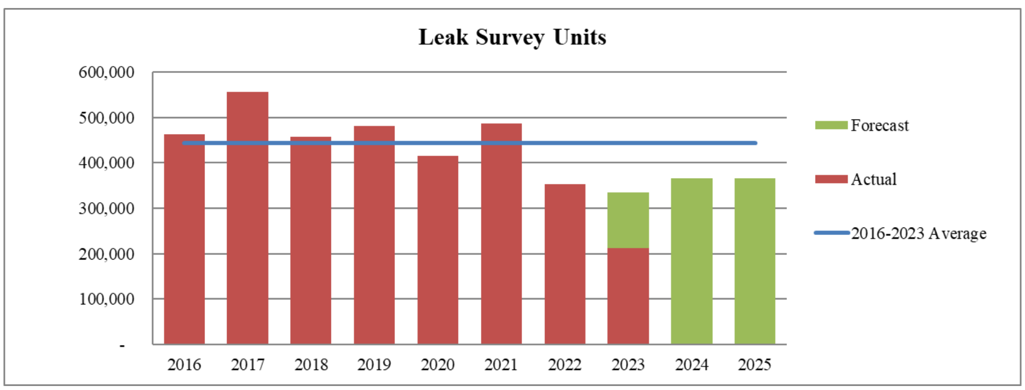


Table 22

Leak Survey	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Actual	462,334	556,249	457,641	480,394	415,305	489,961	353,267	212,850 YTD August		
Forecast								334,002 Year Ending	366,490	366,490

The historical and projected Number of Leaks found during Leak Survey in this sub-program is summarized in Figure 2 with the data provided in Table 23.

Figure 2

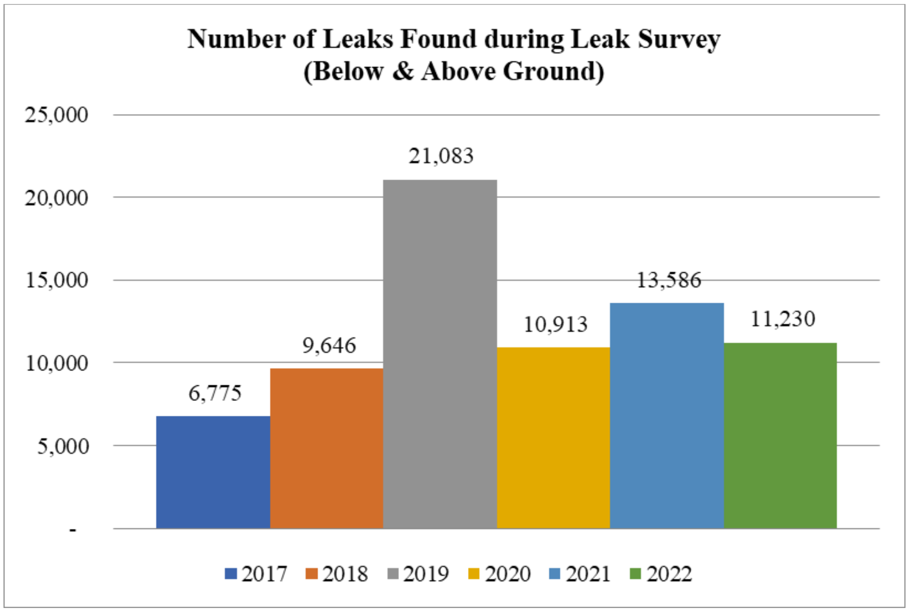


Table 23

Leaks Found During Survey						
	2017	**2018**	**2019**	**2020**	**2021**	**2022**
Above Grade	5,220	7,931	18,393	9,842	12,009	9,714
Below Grade	1,555	1,715	2,697	1,589	1,577	1,516
Total	6,775	9,646	21,090	11,431	13,586	11,230

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 is summarized in Figure 3 with the data provided in Table 24.

Figure 3

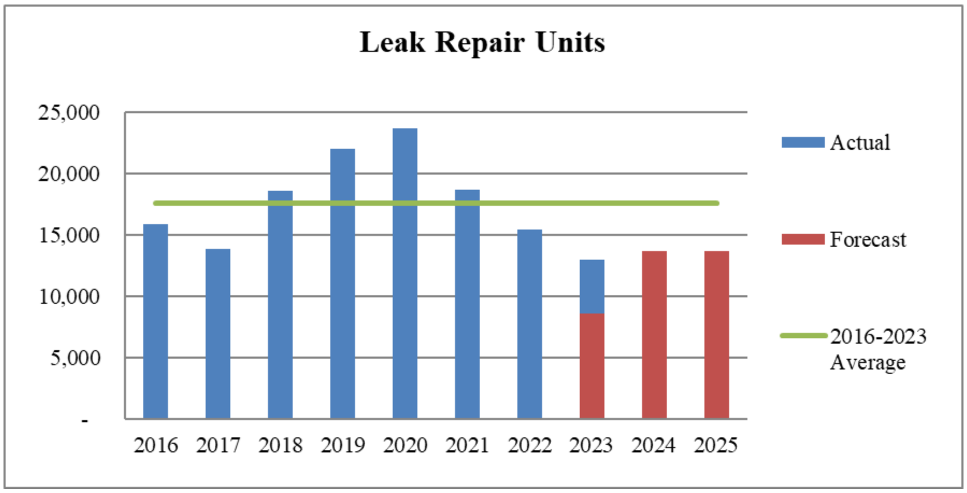


Table 24

Leak Repair	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Actual	15,814	13,815	18,556	21,970	23,649	18,612	15,371	4,405 YTD August		
Forecast								12,970 Year Ending	13,668	13,668

The historic and forecasted Leak Classification units are shown in Figure 4 with data provided in Table 25.

Figure 4

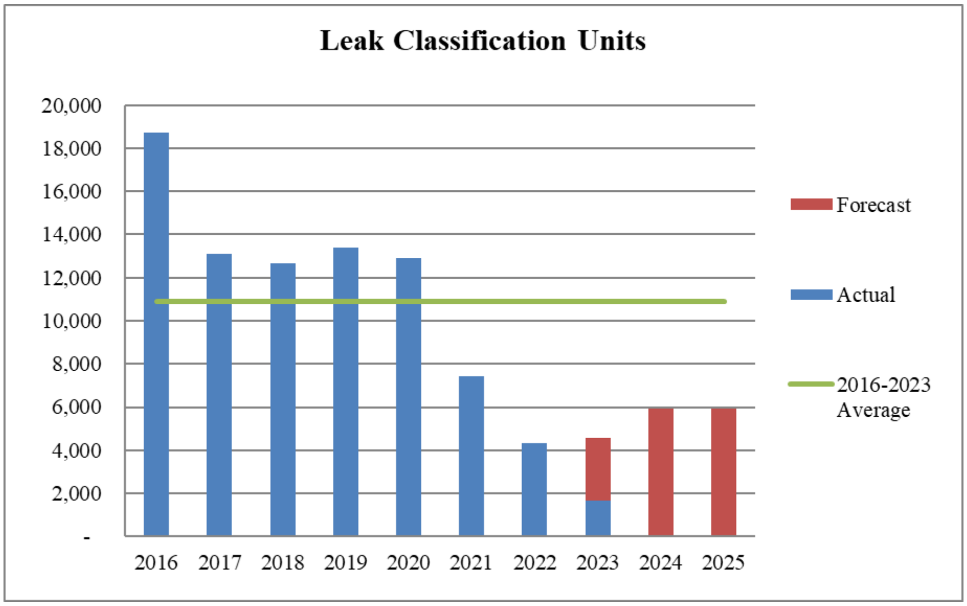


Table 25

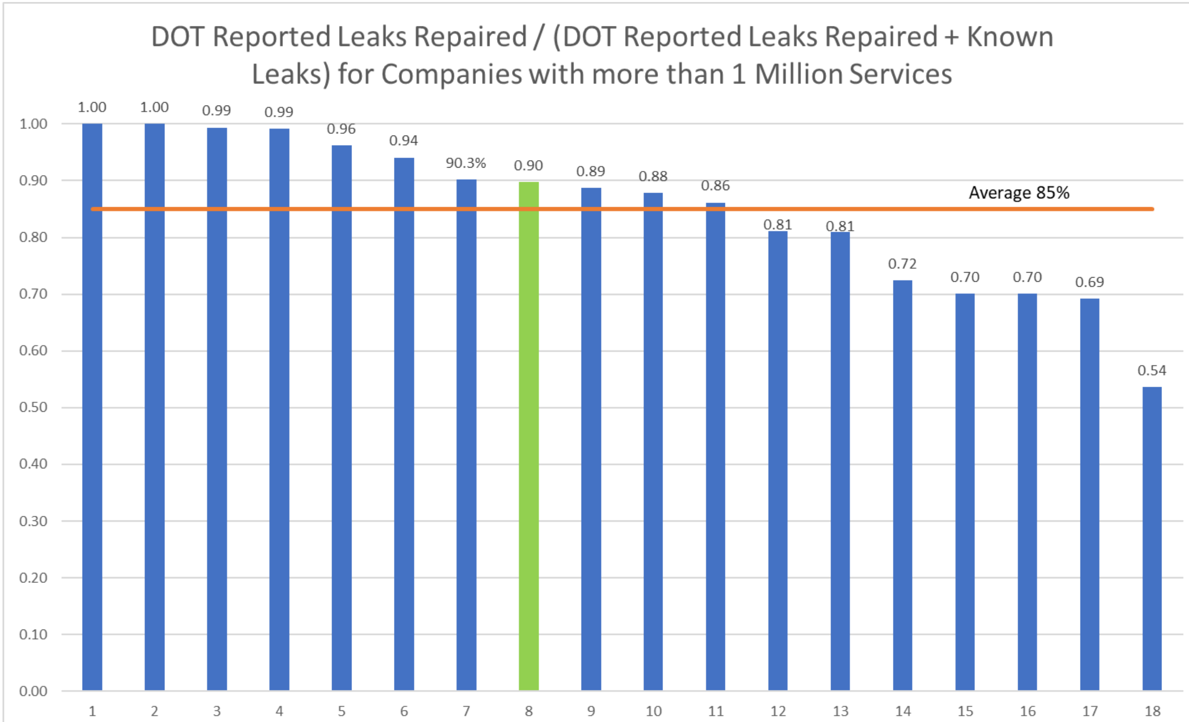
Leak Classification	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Actual	18,734	13,079	12,650	13,374	12,923	7,438	4,332	1,657 YTD August		
Forecast								4,584 Year Ending	5,908	5,908

The graph below depicts a comparison of natural gas utilities with more than 1 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 90.3% as of year-end 2022, which is above industry average of 85%. Based on benchmarked data, shown in Figure 5 below, the Company is seeking to position itself in the top of the first quartile, which drives improved system integrity and public safety.

Figure 5



The leak repairs planned for 2024 and 2025 will ensure the Company maintains a safe and reliable natural gas system by permanently repairing leaks and managing classifying actionable leaks. Current Company practices for managing gas leaks are within the requirements of MGSS, as well as internal standards. By balancing the number of actionable below- and above-grade leaks being tracked on the gas system (Grade 2 and Grade 3 leaks), the Company can enhance public safety, increase the integrity of the natural gas system, and begin lowering long-term costs. With this plan, the Company will still carry a manageable backlog of actionable leaks out of 2023 and into future years. 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 2022 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 26

Distribution ($/hr)				
	Standard Labor Rates	**Indirect Labor Rates**	**Vehicle Rates**	**Total Rate**
2022	$68.24	$36.17	$47.09	$151.49
2023	$69.86	$37.72	$43.31	$150.90
2024	$73.41	$39.64	$48.45	$161.50
2025	$76.23	$41.16	$50.31	$167.71

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

Table 27

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 Projected	336,444	3,569	9,208	40,864	$12,493,487
2024 Projected	364,481	5,705	15,841	47,424	$12,221,729
Projected 12-Mos Ending Sep 30, 2025	364,481	5,705	15,841	47,424	$12,221,729

The projection for the 12-month ending September 30, 2025 is a weighted average of the 2024 (27%) and 2025 (73%) forecast amounts, which reflect the Company's historical experience of program expense timing.

Q. Please describe Advanced Methane Detection.

A. The Company currently conducts leak surveys with handheld instrumentation through foot patrol of gas service lines and infrastructure. Advanced Methane Detection utilizes higher sensitivity instrumentation to detect smaller amounts of gas release than traditional tools. This is further explained in Company witness Kristine A. Pascarello's testimony.

Q. Is there currently any proposed regulation that may increase spending in this sub-program in the future?

A. Yes. The Company is reviewing the PHMSA publication proposing advanced leak detection requirements ("NPRM Leak Detection and Repair"). The publication outlines proposed requirements for advanced leak detection equipment, enhanced leak detection practices, increased leak survey frequency, and defined repair timing for all leaks.

<u>Damage Repair</u>

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 various 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 28

Operation & Maintenance – Damage Repair Projection Breakdown by Activity Type		
Work Type	**2022 Actual**	**Test Year**
Service/Meter Stand Repair	$2,946,935	$2,267,873
Main Repair	$666,297	$545,746
Damage Assessment	$258,979	$212,123
Credits	($2,297,316)	($1,948,742)
Total Program	**$1,574,894**	**$1,077,000**

Q. What is the basis for determining the $1,077,000 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, utilizing damage prevention liaisons, which seeks 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 2023 and 2024. 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 29

Distribution ($/hr)				
	Standard Labor Rates	Indirect Labor Rates	Vehicle Rates	Total Rate
2022	$68.24	$36.17	$47.09	$151.49
2023	$69.86	$37.72	$43.31	$150.90
2024	$73.41	$39.64	$48.45	$161.50
2025	$76.23	$41.16	$50.31	$167.71

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

Table 30

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 Projected	15,194	$511,341
2024 Projected	14,671	$1,077,000
Projected 12-Mos Ending Sep 30, 2025	14,671	$1,077,000

The test year projection is a weighted average of the 2024 (16%) and 2025 (84%) forecast amounts, which reflect the Company's historical experience of program expense timing.

<u>Staking & Locating</u>

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, MISS DIG 811 Underground Facility Damage Prevention and Safety Act, which is 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 - Gas only: contractor costs are included in the test year projection for staking and locating activities that will be performed under the Gas Only Staking programs in the counties of Oakland, Kent, Kalamazoo, and Ingham.
- Outside Services - supplemental retainer vendor: costs and units are included in the test year projection for additional contractor services for Statewide supplemental support to alleviate unforeseen short-term demand increases that the contractors are not able to support.
- 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 2022 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 2022 and the test year expenses are identified in the table below:

Table 31

Staking and Locating Sub-program Projection Breakdown by Activity Type		
Work Type	**2022 Actual**	**Test Year**
Outside Services – Staking and Locating	$8,520,374	$6,573,978
Outside Services - Gas only	$0	$7,543,345
Outside Services - supplemental retainer vendor	$0	$97,649
Company labor	$1,412,752	$1,751,831
Licenses, Permits & Fees	$376,112	$384,332
Total Program	**$10,309,238**	**$16,351,135**

Q. What is the basis for determining the $16,351,135 of projected O&M expenses for this sub-program?

A. Spending in this sub-program is primarily driven by staking request volume (units). Table 34 shows the change in staking volumes realized year over year. The primary drivers for this increase include (a) increase in the cost per ticket under the contracts with staking contractors ($1,917,907); (b) anticipated contractor volume increases ($577,599); (c) implementation of supplemental retainer mechanism ($97,649); (d) Company labor standard labor rate change and volume increase ($339,079); (e) increases in MISS DIG 811 membership fees ($8,220); and (f) the Gas Only asset locating program and expansion ($3,101,443). Historical and forecasted expenses for the Staking sub-program are provided in the table below.

Table 32

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 Projected	$12,523,954
2024 Projected	$14,290,705
Projected 12-Mos Ending Sep 30, 2025	$16,351,134

The test year expense projection is based on a weighted average of the 2024 (17%) and 2025 (83%) 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 in alignment with historical data and 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 3.75% is included in the test year projection relative to 2023 contractor services. This is in alignment with 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 33

Contractor Stake & Locate Services		
	Base Unit cost ($/unit)	**Base Unit Forecast (units)**
2022	$21.83	407,551
2023 Projected	$26.19	419,094
2024 Projected	$30.14	419,097
2025 Projected	$34.55	440,053

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 34

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	1.00%
2023 Forecast	1,177,461	7.7%
2024 Forecast	1,236,334	5% assumed

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 35

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 Projected	2,877	10,492
2024 Projected	2,589	10,356
Projected 12-Mos Ending Sep 30, 2025	2,645	10,582

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

Table 36

Distribution ($/hr)				
	Standard Labor Rates	**Indirect Labor Rates**	**Vehicle Rates**	**Total Rate**
2022	$68.24	$36.17	$47.09	$151.49
2023	$69.86	$37.72	$43.31	$150.90
2024	$73.41	$39.64	$48.45	$161.50
2025	$76.23	$41.16	$50.31	$167.71

Q. Please describe the test year costs for the Gas Only 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. Costs were calculated based on vendor information and are typically higher than shared utility staking vendor work. This is due to having dedicated resources versus shared costs with other facilities in the shared resource model. Additionally, based on the existing benefits realized for the Gas Only staking program that was implemented on February 21, 2023, the Company plans to expand the program to now include all of Oakland County, Kent County, Kalamazoo County, and Ingham County.

Q. Why did the Company implement the Gas Only Staking strategy?

A. Changes in the program are 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 4^{th} quartile for third-party gas distribution damages per 1,000 tickets. When accuracy and timeliness of staking are off target, this can create negative behaviors with 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 the Gas Only 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 greatly 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 will only need to focus on one utility type compared to the shared resource model, where stakers are responsible for all assets (electric, 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. Why did the Company choose to start the Gas Only Staking Program instead of hiring more contract stakers to improve staking quality?

A. Hiring additional contractors would follow the shared resource model, which uses staking resources across several companies and assets. The shared resource model carries risks, including skilling proficiencies related to delivering timeliness and quality performance as it relates to staking existing gas infrastructure. The Gas Only Staking Program uses a dedicated resource for only Company gas assets, so stakers can become efficient and proficient on gas staking without having to focus on locating electric, communications, water, etc. The gas-only dedicated workforce model substantially mitigates many of the risks associated with the shared resources model.

Q. Why did the Company choose Oakland County as the initial location for the Gas Only Staking Program?

A. The Gas Only staking program was implemented as planned in Oakland County on February 21, 2023, and is now active. Oakland County makes up 29% of the Company's staking requests. From 2019 through 2022, Oakland County had the highest 3rd Party Gas Damages with Locate Contractor Fault. Focusing on the location with the highest percentage of staking requests and 3rd Party Gas Damages mitigates risks to public safety, damages, timeliness, quality, and communication with excavators.

Other factors used in the Company's decision to select Oakland County for this program was that (1) the county predominately contains gas only assets; (2) the area provides program expansion opportunities geographically; and (3) the county has the highest volume of staking tickets and damages. The figures below demonstrate room for continuous improvement in Oakland County. The figures show Timeliness and 3rd Party Gas Damages w/Locate Contractor Fault to support why Oakland County was chosen.

Figure 6

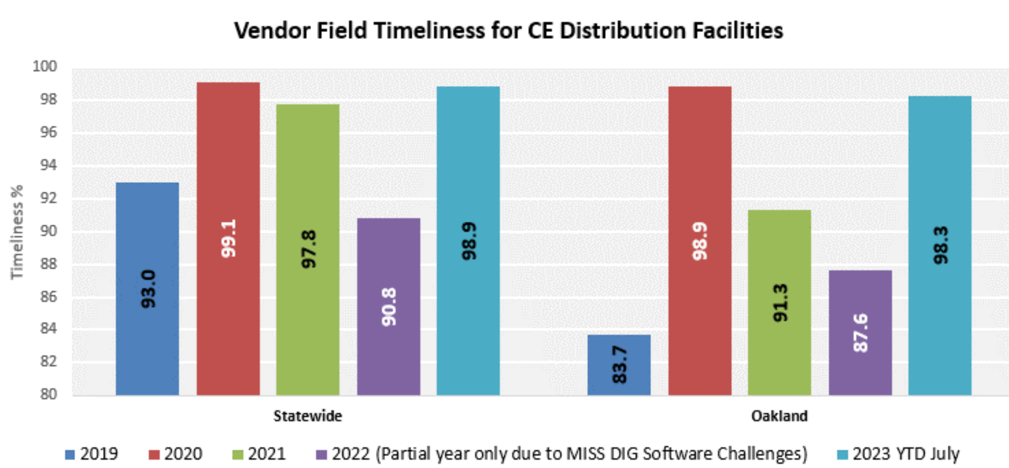
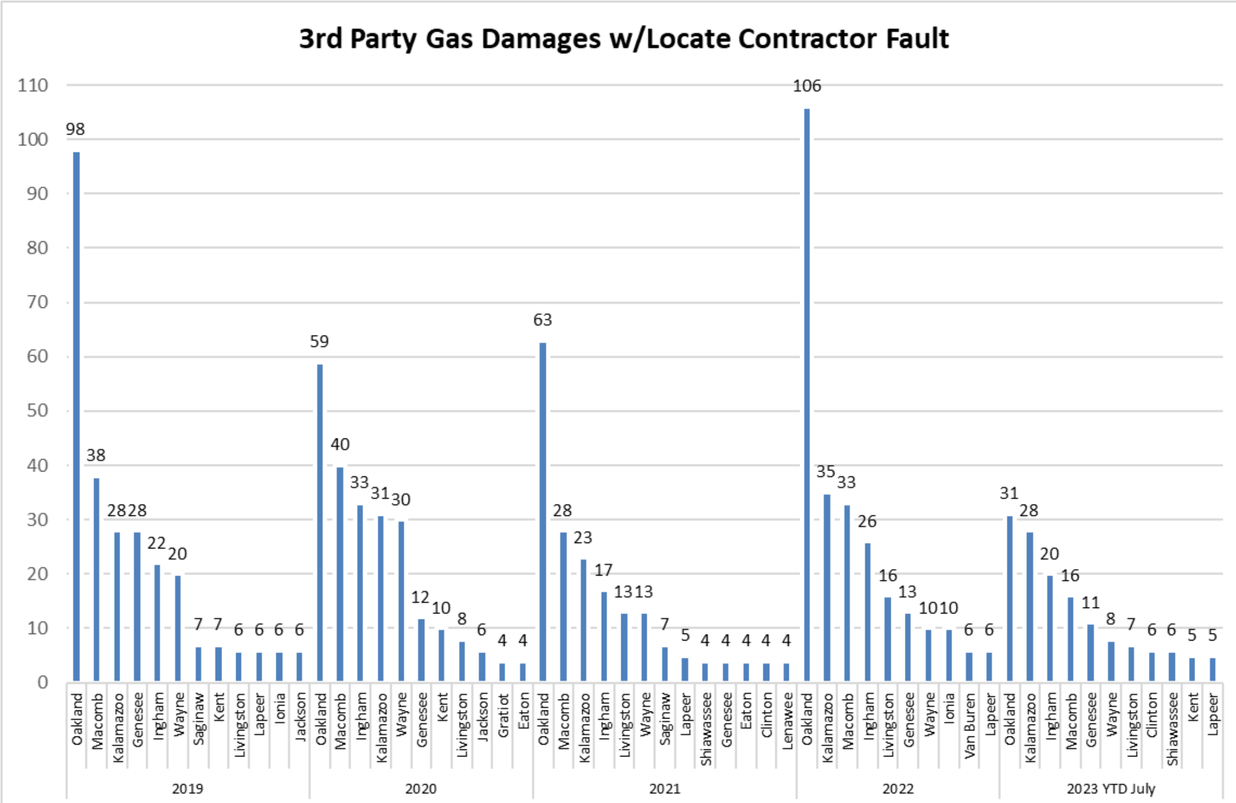


Figure 7



Q. Please describe the benefits the Company has seen since implementing the Gas Only Staking Program.

A. The Company has seen benefits to overall accuracy and timeliness, and excavator communications on projects over the first seven months (month ending September 2023) following implementation Compared to the shared resources model, accuracy related to at-fault damages has improved by 85%, and field timeliness has improved by 1.4%. Overall, the number of damages in the area has decreased by 26%, and this is 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 Company's plan to expand the Gas Only Staking Program.

A. Based on existing benefit realization for the Gas Only 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. The Company plans to expand the Gas Only Staking Program to include Oakland, Kent, Kalamazoo, and Ingham counties by 2025. This aligns with the Company's staking and locating plans discussed in its recent electric rate case, Case No. U-21389. The decision is also supported by the chart above that shows 3rd Party Gas Damages w/Locate Contractor Fault. The graph shows Kalamazoo County and Ingham County are consistently in the Top 5 counties since 2019 with high 3rd Party Gas Damages w/Locate Contractor Faults. In 2023, the Gas Only Staking program covered 2/3 of Oakland County which is 20% of the total staking tickets. The plan for 2024 will have the Gas Only Staking program covering 31% of the total staking tickets and will include Oakland and Kent counties. The plan for 2025 will have the Gas Only Staking program covering 43% of the total staking tickets and will include Oakland, Kent, Lansing, and Kalamazoo counties.

Kent County was chosen over other counties with higher 3rd Party Gas Damages w/Locate Contractor Faults, to align the gas program with the Company's Electric Only staking program presented in the electric rate proceeding, Case No. U-21389.

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 PSO - Damage Prevention 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 relights 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 37

Operations & Maintenance – Customer Requested Services		
Projection Breakdown by Activity Type		
Work Type	**2022 Actual**	**Test Year**
Non WBS	$839,832	$934,794
Contractor; Materials, Credits and Other Expenses	$558,955	$181,112
Cust Req Services	$4,890,643	$4,396,644
Charts & Inspections	$2,003,899	$1,380,342
Routines	$2,761,679	$3,020,934
Meter Work	$8,143,241	$7,991,406
Total Program	**$19,198,250**	**$17,683,000**

Q. What is the basis for determining the $17,683,000 of O&M expenses in the test year 12 months ending September 30, 2025, 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. Gas Service worker hourly standard labor rates are expected to be:

Table 38

Service ($/hr)				
	Standard Labor Rates	Indirect Labor Rates	Vehicle Rates	Total Rate
2022	$68.09	$93.28	$27.92	$189.29
2023	$70.23	$105.35	$25.99	$201.56
2024	$73.80	$103.32	$29.52	$206.64
2025	$76.63	$107.28	$30.65	$214.56

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

Table 39

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 Projected	146,853	81,311	$17,892,903
2024 Projected	148,780	80,174	$17,683,000
Projected 12-Mos Ending Sep 30, 2025	148,780	80,174	$17,683,000

The test year expense projection is based on a weighted average of the 2024 (29%) and 2025 (71%) 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. 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 ($6,504,012) projected O&M credit in the test year 12 months ending September 30, 2025?

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 43,802 new gas meters. The expected credit from these purchases during the test year is $5,066,000. 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 44,280 existing gas meters. The expected credit from these meter retirements is $1,438,012. 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 September 30, 2025 are shown in the table below:

Table 40

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 Projected	37,003	41,632	($7,389,672)
2024 Projected	42,219	44,280	($6,504,012)
Projected 12-Mos Ending Sep 30, 2025	43,803	44,280	($6,504,012)

The test year expense projection is a weighted average of the 2024 (25%) and 2025 (75%) 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 $1,714,000 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 time frame 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 cost of the clearing program.

Table 41

Right-of-Way Clearing		
Projection Breakdown by Activity Type		
Work Type	**2022 Actual**	**Test Year**
Salary & Expenses	$207,390	$222,356
Mechanical Clearing Treatments	$1,339,169	$1,223,398
Herbicide Treatments	$280,708	$268,246
Total Program	**$1,827,267**	**$1,714,000**

Q. What is the basis for determining the $1,714,000 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 third full year of the plan implementation in 2022, the Company spent $1,827,267 and is targeting and on track to spend $1,745,000 in 2023. The 2023 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 $1,714,000. The projected cost decrease reflects the program theoretically being on cycle. So rather than reclaiming the ROW as in previous years, the Company is entering the managing phase of the program. The 2020 Actual miles and expense through the 2025 plan miles and expense are shown in the table below.

Table 42

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 Projected	400	$1,745,000
2024 Projected	400	$1,714,000
Projected 12-Mos Ending Sep 30,2025	400	$1,714,000

The test year expense projection is a weighted average of the 2024 (34%) and 2025 (66%) 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 has been transitioning from manually reading meters to Gas AMR technology for a large portion of its gas service customers. The Company achieved overall year-end gas meter read rates of 99.74% in 2021 and 99.76% in 2022. The year-end meter reading results for 2021 and 2022 for the various processes used by the Company are as follows:

Table 43

	Meters Available		**Meters Read**		**Meter Read Rate**	
Year	**2021**	**2022**	**2021**	**2022**	**2021**	**2022**
Gas AMR	13,751,429	13,699,110	13,726,701	13,685,051	99.86%	99.90%
Gas AMI	8,140,073	8,006,601	8,128,731	7,986,287	99.91%	99.75%
Manual Gas Reads	180,394	168,382	158,628	150,886	78.92%	89.61%

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 ending September 30, 2025, is projected to be 40% Electric and 60%Gas; in 2022, the allocation was split 40.1% Electric and 59.9% Gas. The difference between the 2022 actual and projected test year electric and gas allocation considers the optimization of AMR and manual routes.

A comparison of the 2022 actual and test year projection is provided below:

Table 44

Meter Reading		
Projection Breakdown by Activity Type		
Work Type	**2022 Actual**	**Test Year**
Meter Reader Salaries	$314,284	$323,010
Supervision & Administration Salaries	$1,674,696	$1,599,336
Meter Reading Expenses	$603,267	$701,521
Total Program	**$2,592,247**	**$2,623,867**

Q. What is the basis for determining the $2,623,867 of projected O&M expenses in the test year 12 months ending September 30, 2025 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 $2,623,867, which is an increase of $31,620 because of increased fuel cost 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 15,674 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 45

August 2023	
Gas Customers Not Cut Over To AMI/AMR	
Description	**Manually Read Meters Count**
Legacy Not Cut Over	4,543
Legacy Opt Out Not Cut Over	5,329
Legacy Rates Ineligible for GCM	2,975
Total Legacy Not Cut Over	**12,847**
GCM AMR Not Cut Over	1,001
GCM AMR Opt Out Not Cut Over	0
GCM AMR Rates Ineligible	863
GCM AMI Not Cut Over	819
GCM AMI Opt Out Not Cut Over	0
GCM AMI Rates Ineligible	144
Total Smart Not Cut Over	**2,827**
GRAND TOTAL NOT CUTOVER	**15,674**

The following table provides the actual meter reading O&M cost for 2016 through 2022, as well as forecasted amounts for 2023 through the test year:

Table 46

Meter Reading		
Equivalent Staffing & Dollars		
	Average	
Year (Jan-Dec)	Gas Staff	Dollars
2016		$13,582,033
2017		$12,328,228
2018	112.0	$10,499,528
2019	67.0	$7,633,272
2020	31.0	$4,097,383
2021	23.0	$2,830,688
2022	22.0	$2,592,247
2023 Projected	22.0	$2,540,868
2024 Projected	22.0	$2,623,867
Projected 12-Mos Ending Sep 30, 2025	22.0	$2,623,867

The expense projection for the 12 months ending September 30, 2025 is a weighted average of the 2024 (23%) and 2025 (77%) forecast amounts, which reflect the Company's historical experience of program expense timing.

<u>**Meter Technology and Management System Support**</u>

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 of 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 2022 historical expense and the test year projected expense are summarized in the following table:

Table 47

Meter Tech & Mgmt Sys Support		
Projection Breakdown by Activity Type		
Work Type	**2022 Actual**	**Test Year**
Exempt/Non-Exempt Salaries	$245,697	$261,910
OM&C Salaries	$860,762	$861,874
Expenses	$170,841	$325,767
Meter Correctors (began to purchase as O&M in 2022)	$150,485	$1,538,500
Total Program	**$1,427,785**	**$2,988,051**

Q. What is the basis for determining the $2,988,051 projected O&M expenses in the test year 12 months ending September 30, 2025, 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 are considered replacement parts and will be purchased under the O&M program going forward, starting in 2022. The change in purchasing instrument correctors in this program represents a $1,538,500 impact in the test year, purchasing 1700 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 2022, as well as forecasted amounts for 2023 through the projected test year:

Table 48

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 Projected	$982,895	$369,005	$1,351,899
2024 Projected	$1,131,784	$1,856,268	$2,988,052
Projected 12-Mos Ending Sep 30, 2025	$1,131,784	$1,856,268	$2,988,052

The test year expense projection is a weighted average of the 2024 (28%) and 2025 (72%) forecast amounts, which 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; and (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 49

Smart Energy MTC – Gas		
Projection Breakdown by Activity Type		
Work Type	**2022 Actual**	**Test Year**
Communication Charges	$282,160	$281,137
GCM Software Maintenance	$167,038	$168,750
Technical Support Services Contract	$93,750	$125,000
Total Program	**$542,948**	**$574,887**

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 September 30, 2025, are shown in the table below:

Table 50

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 Projected	$563,225
2024 Projected	$574,888
Projected 12-Mos Ending Sep 30. 2025	$574,888

The test year expense projection is a weighted average of the 2024 (24%) and 2025 (76%) 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, 826 gas storage wells, and 258 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 51

Gas Storage O&M		
Projection Breakdown by Activity Type		
Work Type	**2022 Actual**	**Test Year**
Non WBS	$1,879,267	$1,071,343
Contractor; Materials, Credits and Other Expenses	$1,630,826	$679,314
Code Inspections	$1,446,396	$1,580,343
Facilities Locating for Third Parties (MISS DIG 811)	$599,035	$654,511
Demand/Preventive/Compliance Maintenance	$908,038	$992,129
Operations	$90,358	$98,726
Less: Facility Chargebacks	($215,856)	($166,066)
Total Program	**$6,338,065**	**$4,910,300**

Q. What is the basis for determining the $4,910,300 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 is 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 52

Transmission ($/hr)				
	Standard Labor Rates	**Indirect Labor Rates**	**Vehicle Rates**	**Total Rate**
2022	$66.51	$30.59	$49.22	$146.32
2023	$69.18	$24.90	$36.67	$130.75
2024	$72.53	$25.39	$38.44	$136.36
2025	$75.33	$26.37	$39.92	$141.62

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

Table 53

Gas Storage O&M Dollars		
Year (Jan-Dec)	**Less: Facility Chargebacks**	**Dollars**
2016	($134,826)	$7,062,022
2017	($128,356)	$5,667,339
2018	($181,171)	$6,305,807
2019	($135,640)	$6,187,826
2020	($134,836)	$5,821,338
2021	($174,015)	$5,860,452
2022	($215,856)	$6,338,065
2023 Projected	($183,116)	$6,136,883
2024 Projected	($166,066)	$4,910,300
Projected 12-Mos Ending Sep 30, 2025	($166,066)	$4,910,300

The test year expense projection is a weighted average of the 2024 (27%) and 2025 (73%) 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.

<u>Replace Vintage Services</u>

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 area summarized in the following table:

Table 54

Replace Vintage Services		
Projection Breakdown by Activity Type		
Work Type	**2022 Actual**	**Test Year**
Replace Vintage Services	$98,417	$70,289
Total Program	**$98,417**	**$70,289**

Q. What is the basis for determining the $70,289 of projected O&M expenses in the test year for this sub-program?

A. The forecast for 2024 and 2025 anticipates that a small percentage of RVS construction orders will be returned from the field as non-constructible. The Company plans to replace 2,796 services in 2024 and 4,462 services in 2025. The expected non-constructible rate is expected to be 1.25% of planned units.

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

Table 55

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 Projected	1,475	1.25%	$96,000
2024 Projected	2,796	1.25%	$70,289
Projected 12-Mos Ending Sep 30. 2025	4,045	1.25%	$70,289

The test year expense projection is a weighted average of the 2024 (41%) and 2025 (59%) forecast amounts, which reflect the Company's historical experience of program expense timing.

<u>**Gas Operations Field Operations**</u>

Q. Please describe the O&M expenses related to the Gas Field Operations sub-programs shown on Exhibit A-103 (JPP-3).

A. The Gas Field Operations sub-programs includes training for approximately 1,400 natural gas field operations employees, 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.

<u>Training</u>

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

A. The Training sub-program includes training for approximately 1,400 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 56

Operation & Maintenance – Training Projection Breakdown by Activity Type		
Work Type	**2022 Actual**	**Test Year**
Gas Operations OM&C Training	$4,757,811	$4,246,734
Athletic Trainers	$273,098	$310,463
Gas Training Non-Labor Expense	$1,174,683	$88,142
Total Program	**$6,205,592**	**$4,645,339**

Q. What is the basis for determining the $4,645,339 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 that are conducted for Gas Operations employees. This training is required to allow for a skilled and qualified field operations workforce 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 57

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 Projected	74,704	$5,122,580
2024 Projected	70,372	$4,645,339
Projected 12-Mos Ending Sep 30, 2025	70,372	$4,645,339

The test year expense projection is a weighted average of the 2024 (22%) and 2025 (78%) forecast amounts, which reflect the Company's historical experience of program expense timing.

<u>Tools</u>

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 allows employees to 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 that are in the field and 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 $1,565,000 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 for the test year period. The historical and projected activity in this program is summarized in the following table.

Table 58

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 Projected	$1,768,000
2024 Projected	$1,565,000
Projected 12 Mos Ending Sep 30, 2025	$1,565,000

The test year expense projection is a weighted average of the 2024 (29%) and 2025 (71%) 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 2022 and the projected test year expenses are provided in the table below:

Table 59

Field Operations Expenses		
Projection Breakdown by Activity Type		
Work Type	**2022 Actual**	**Test Year**
Field Ops OM&C Gas Expenses	$1,518,747	$972,953
Field Ops OT Meals Gas	$333,796	$254,629
Pipeline User Fees	$699,394	$717,532
Permits	$112,214	$89,869
Gas Field Mobility Exp	$210,459	$239,650
Gas Bonds	$1,025,195	$434,367
Total Program	**$3,899,805**	**$2,709,000**

Q. What is the basis for determining the $2,709,000 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. As shown in Exhibit A-103 (JPP-3), page 2, line 3, column (i), spending in this sub-program is $1,539,000 less than would be accounted for by inflation from 2022 actuals. The reason for this decrease in spending is driven primarily by increased net bond recovery costs along with lower OM&C Gas Expenses.

Table 60

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 Projected	$2,925,000
2024 Projected	$2,709,000
Projected 12 Mos Ending Sep 30, 2025	$2,709,000

The test year expense projection is a weighted average of the 2024 (9%) and 2025 (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 what the Company's actual operating employees' wages and the amount of salary cost that are 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 have 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 of 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-103 (JPP-3) page 1, lines 5, 6, and 7.

Q. What is the basis for determining the $5,238,000 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 labor and expenses. In 2021, this program only included employees from Gas Service and Gas Distribution. During the historical year of 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 that are 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 38 employees. The historical year costs and projected test year costs and headcounts are summarized in the following table:

Table 61

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 Projected	126	48	17	191	$5,674,000
2024 Projected	124	47	19	190	$5,167,498
Projected 12-Mos Ending Sep 30, 2025	124	47	19	190	$5,238,000

The test year expense projection for the 12 months ending September 30, 2025 is a weighted average of the 2024 (25%) and 2025 (75%) forecast amounts, which reflect the Company's historical experience of program expense timing.

<u>Dispatch & Scheduling</u>

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. It is also responsible for the gas meter Consecutive Estimate Program, which manages customer accounts (approximately 1,500) with three or more consecutive estimates through an escalation process that 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 2022 and the projected test year expenses are provided in the table below:

Table 62

Dispatch and Scheduling		
Projection Breakdown by Activity Type		
Work Type	**2022 Actual**	**Test Year**
Dispatch and Scheduling	$1,371,650	$1,275,930
Total Program	**$1,371,650**	**$1,275,930**

Q. What is the basis for determining the $1,275,930 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 this 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 63

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 Projected	$1,315,000
2024 Projected	$1,251,852
Projected 12 Mos Ending Sep 30, 2025	$1,275,930

The test year expense projection is a weighted average of the 2024 (27%) and 2025 (73%) 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 64

EIRP O&M		
Projection Breakdown by Activity Type		
Work Type	**2022 Actual**	**Test Year**
EIRP Supervision & Admin Sal/Exp	$874,904	$899,756
EIRP Tools	$126,553	$134,833
EIRP OM&C Expenses (Non-Labor)	$19,592	$24,708
EIRP Facilities	$253,348	$353,500
EIRP Labor OM&C Training	$3,096,001	$2,408,203
Total Program	**$4,370,398**	**$3,821,000**

Q. What is the basis for determining the $3,821,000 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 that will allow for an appropriate staffing as the Company implements the NGDP. Based on projections, this will result in decreased spending compared to 2022. 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 headquarter 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, which are based on the amount of vintage pipe to be replaced. 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 65

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 Projected	$3,124,525
2024 Projected	$3,821,000
Projected 12 Mos Ending Sep 30, 2025	$3,821,000

The test year expense projection is a weighted average of the 2024 (23%) and 2025 (77%) forecast amounts, which reflect the Company's historical experience of program expense timing.

<u>**Gas Operations Performance**</u>

Q. Please describe the expenses related to the Gas Operations Performance O&M Program shown on Exhibit A-104 (JPP-4).

A. The Gas Operations Performance ("Ops Performance") Department represents a department within the Consumers Energy Operations organization that began in 2017. The Ops Performance team includes 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 consists of the following functions that are focused on streamlining processes to achieve first-time quality for our customers: (1) Work Management Excellence, (2) Process, Analytics & Technology, and (3) Industrial Engineering, each described below.

- Work Management Excellence includes functions for Distribution Planning, Scheduling, Close-Out, Statewide Admin, and Customer Energy Management 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 that the operating plan adheres to the MPSC-approved business plan for Gas Operations field work.

  - Scheduling ensures that 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 that 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 Excellence Team assumed responsibility, costs, and headcount of the Customer Energy Management ("CEM") team from Gas Engineering in 2023.

  - 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 three 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.

- Process, Analytics & Technology includes functions for process improvement, waste elimination, data strategy, data science, data analytics, performance reporting, and technology. In 2023, 14 resources were shifted from other departments within Operations and Engineering to better align like work with like work which enables standardization and synergies. The alignment was neutral to the gas business.

- The Industrial Engineering team was first formed in 2021 with a mission to improve safety, quality, cost and delivery. This team includes experts in the industrial engineering trade, technical writers, standardization processes, and governance.

Table 66

Gas Operation Performance		
Projection Breakdown by Activity Type		
Work Type	**2022 Actual**	**Test Year**
Gas Operation Performance	$4,955,000	$2,848,000
Total Program	**$4,955,000**	**$2,849,000**

Q. What is the basis for determining the projected $2,849,000 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 Operations Performance 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 67

Gas Operations Performance O&M Headcount & Dollars		
Year (Jan-Dec)	**Headcount**	**Dollars**
2019	74	$1,141,000
2020	72	$1,005,000
2021 (1)	285	$3,211,000
2022 (2)	244	$4,955,000
2023 Projected (3)	449	$3,325,000
2024 Projected	415	$2,849,000
Projected 12 Mos Ending Sep 30, 2025	415	$2,849,000

(1) Reorganization in February 2021
(2) Attrition and a Reorganization occurred in 2022.
(3) Completed major project and Reorganization in 2023

<u>Gas Operations Management</u>

Q. Please describe the expenses related to the Gas Operations Management O&M Program shown on Exhibit A-104 (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 68

Gas Operations Management O&M Projection Breakdown by Activity Type		
Work Type	**2022 Actual**	**Test Year**
Gas Operations Management	$2,094,000	$1,304,000
Total Program	$2,094,000	$1,304,000

Q. What is the basis for determining the projected $1,304,000 O&M expenses in the test year for this program?

A. The 2022 actual expense for the Gas Operations Management Program was $2,094,000. The historical actual amount of program expense is detailed by labor and various non-labor expense components in Exhibit A-104 (JPP-4), page 1, line 3, column b.

The Company's projected test year expense is $1,304,000 as shown on Exhibit A-104 (JPP-4), page 2, line 3, column j. The projected test year decrease from 2022 actual expense is primarily the result of a decrease of material and labor costs to this program. The historical and projected cost summary is shown in the below table:

Table 69

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 Projected	$1,219,000
2024 Projected	$1,325,000
Projected 12 Mos Ending Sep 30, 2025	$1,304,000

<u>IT PROJECTS</u>

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 projects providing customer benefits for the areas which I am sponsoring are described below:

- The **Field Contractor Work Management Technology Enablement** project requires $168,549 in capital and $1,146 in O&M in the test year. The project provides the ability to electronically manage contractor work and increases accuracy and timeliness of information processing for field work deliverables. This project additionally creates new opportunities to measure and optimize field work processes supporting customer on-time delivery goals. Contractor field employees use manual, paper-based processes and generic communication technologies (phone, radio, email, collaboration sites) to perform work for the Company. Due to the non-electronic format, inaccuracy, and delay of information processing there are negative impacts to the availability and accuracy of work status. This limits the opportunity to measure and optimize field work processes that support customer on-time delivery and other goals. The project will add value by: (1) improving on-time delivery of customer work by providing electronic work order information to contractors; (2) improving customer satisfaction through efficiency in scheduling work and reporting on the progress electronically; (3) increasing safety by tracking work and contractor status providing visibility into the last known location of the contractor; (4) improving material management; (5) making it easier to move emergent work to contractors to balance workloads and meet customer commitments; and (6) enabling real time updates to work order information, increasing data accuracy and reducing invoice reconciliation time. The project scope includes: (1) identifying requirements for a Bring Your Own Device ("BYOD") field contractor work management technology solution and process; (2) developing, configuring, and testing interfaces, hardware, and software for the solution; (3) implementing the solution and process for the following work groups: Gas Distribution and Gas Code Compliance; (4) updating the following vendor contract types to support BYOD field contractor work management: zone, specific bid, ancillary, electric storm, and mutual assistance; and

(5) training field contractors on the new technology and processes. The alternatives considered included: (1) Continue with the current paper-based process. This alternative was not selected because this approach does not allow for the timely, data-driven work management metrics required to improve service to customers. (2) Use the current Company mobile application. This alternative was not selected because the solution is not expected to receive long-term investments by the vendor and the mobile application would require more upfront investment than the proposed option. (3) Use off-platform options such as ServiceBench. This alternative was not selected because contractors would not be able to leverage the benefits and integrations with the existing platform and it would require additional new integrations. (4) Provide Company-funded field devices to contractors. This alternative was not selected because the investment in hardware, management of on-boarding and off-boarding of devices to contractors, and training and change management is cost-prohibitive and introduces a risk of the loss of control of information security and corporate assets. Leveraging the existing field work management solution was chosen because it uses existing well-developed functionality while leveraging cloud-based, BYOD capabilities to move short-term and long-term contractors from paper processes to the established, standard work management system.

- The **Work Management Scheduling Analytics and Reporting** project requires $122,785 in capital and $2,843 in O&M in the test year. The project will implement a solution to optimize the key components of the Distribution Planning and Scheduling functions including forecasting, work order intake, resource identification, work schedule creation, work execution preparation and associated work order analytics. The Distribution Planning, Scheduling and Administrative Support & Financial Services (Work Plan Strategy) teams are utilizing manually intensive work methods, systems, and forecasting models. These inefficiencies impact the creation of work plans, lack predictive capacity planning, and reduce productivity of operational partners. The project will add value by providing: (1) streamlined processes tied to workload review and preparatory analysis, leading to increased focus on workload priority, execution of work, and a reduction of human struggle; (2)increased accuracy in crew work schedules, leading to improved customer satisfaction and on-time delivery of customer requested work, system integrity work, and gas compliance requirements; (3) reduced manual scheduling steps, reporting and analysis of data associated with work management processes and systems; thereby minimizing the risk of human error hours spent developing and updating crew route sheets; and (4) improved forecasting accuracy, that results in greater transparency into the weekly schedule and associated work plan. The project scope includes: (1) implement a solution to facilitate the review of work orders from various engineering organizations, allowing for streamlined check-in of work orders; (2) implement a scheduling tool that utilizes predictive modelling and advanced analytics and streamlines daily schedule modifications; (3) enhance integration with the Arcos application to bring in employee capacity and availability information; (4) integrate with SAP to retrieve work order data and manage record keeping requirements; (5) enhance integration with Field Service Suite (FSS) for quicker access to MISS DIG 811 information and work order assignments; and (6) implement associated analytics and reporting. Three primary alternatives were considered for this project: (1) Automating manual data movement across excel and current systems through Robotic Process Automation. This option was not chosen because it will not meet base requirements and will not provide desired insights into whether the schedule supports operating priorities and metrics, financial scenarios, first time completion of work, and daily goals; (2) Integrating an off-the-shelf planning and scheduling system. This option is not preferred due to associated up-front and long-term costs; and (3) Implementing a hybrid of an off-the-shelf planning component with custom built scheduling functions. This is the preferred option to provide a more cost-effective and targeted fit for the organization.

- The **Field Supervisor Automation** project requires \$116,240 in capital and \$18,558 in O&M in the test year. Effort to reduce human struggle and automate Field Supervisor tasks, improve start/end of day administration functions and provide additional time in the field that will lead to improved safety and sustainability. Field Supervisor administrative workload is burdensome and causes human struggle that limits operation field leaders time in the field, performing value added work. This administrative overhead limits the ability to complete the work expected of a Field Supervisor. Successful and efficient completion of supervisor management tasks improves Gas operations and ultimately drives improvement in work performance and employee safety. To eliminate or automate administrative tasks currently being performed by Field Supervisors. This would drive a reduction in human struggle and limit the need of costly field supervisor support staff. Lastly, the objective is to produce the best possible working environment by direct involvement from Field Supervisor leadership, producing a safe and productive work environment that benefits all field resources. The current scope includes the following major activities, that include a field supervisor portal, timesheet automation and improving data management into the current call-out system. Timesheet automation will automate the timesheet entry and approval processes and eliminate manual schedule exceptions. The data management will be improved by leveraging improvements in our our call-out system and training data. Additionally, roll-out a workforce friendly mobile version of our call-out application to foster self-service from our field workers, reducing administration by field supervisors. Identify and eliminate any unnecessary administration tasks that hinder field supervisor time in the field. Alternatives that were considered include the following: (1) Staying in the status quo, this was not chosen because of the tremendous opportunity to automate processes that would increase efficiency and ultimately increase safety and efficiency in the field; (2) A custom off the shelf solution by a major vendor, this option was not chosen because of the efficiency and automation improvements that are being targeted for Field Supervisors are efforts that can be dramatically improved without a major software vendor purchase; (3) Improve internal process and enhance and optimize exiting commonly used systems that does not require a major software purchase.

- The **Gas Customer Appointment Booking** project requires $723,896 in capital and $107,917 in O&M in the test year. Implement an electronic solution that leverages the existing applications used by the Call Center and Schedulers to book certain customer driven work directly to a field technician. Currently in Gas Operations the manual updates of customer work center capacity in SAP make it difficult to accurately schedule customer appointments. This results in overbooking appointments, missed customer appointment commitments, wasted field trips, and extra communication with customers. (1) Enable company solution for direct customer appointment booking thorough the call center. (2) Provide a resource capacity planning tool that reflects actual technician capacity and availability. (3) Enable reserving capacity of a field crew to perform the work. (4) Provide appointment availability information in real time so that accurate appointment windows can be offered to a customer. (5) Reserve appointment time for qualified technicians and ensure they are not overbooked. (6) Provide schedulers with the ability to view, modify, or cancel existing appointments. The objectives are to: (1) Update existing call center systems to allow agents to view technician capacity (2) Create an interface to return technician capacity from the resource scheduling and availability system. (3) Enhance the resource and availability system import employee schedules. (4) Enhance work management system to enable viewing, modification or cancellation of customer appointments. Alternatives considered include: (1) Continue with the manual scheduling of customer appointments. This solution was not selected as it results in overbooking appointments, missed customer appointment commitments, wasted field trips, and extra communication with customers. (2) Purchase a third-party Serice as a Solution (SAAS) solution for appointment booking. This solution was not selected because it would increase cost, technical complexity, and delay implementation of a solution. (3) Optimize utilization of existing tools through enhancements to company CRM, customer scheduling, technician availability, and work management applications. This solution was selected because it is cost effective and aligns with the existing technical roadmap, while minimizing business process change.

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	)	Case No. U-21490
distribution of natural gas and for other relief.	)	
	)	

DIRECT TESTIMONY

OF

HEATHER M. PRENTICE

ON BEHALF OF

CONSUMERS ENERGY COMPANY

December 2023

Q. Please state your name and business address.

A. My name is Heather M. Prentice, and my business address is 1945 West Parnall Road, Jackson, Michigan 49201.

Q. By whom are you employed?

A. I am employed by Consumers Energy Company ("Consumers Energy" or the "Company") as the Director of Environmental Compliance, Risk Management & Governance in the Environmental Quality and Sustainability Department.

Q. How long have you been employed by Consumers Energy?

A. I have been employed by Consumers Energy since 2008.

Q. Please describe your educational background and work experience.

A. I graduated from Ohio Northern University in 1999 with a Bachelor of Science degree in Civil Engineering with an Environmental Option. I am a Registered Professional Engineer in the states of Michigan and Ohio. My environmental investigation and remediation work experience spans over 20 years and includes a variety of technical and managerial responsibilities.

After graduating in 1999, I started working for Water Resources & Coastal Engineering, a consulting firm based in Solon, Ohio. As a project engineer, my responsibilities included modification of the facilities planning reports for the City of Cleveland's four major water treatment plants per review comments, analysis of pump performance for various service levels (pressure zones), and estimation of the construction costs for various projects recommended in the plan. I then worked at Camp, Dresser & McKee in its Cleveland, Ohio office. As project engineer, I managed tasks from multiple projects including odor sampling, soil removal, water treatment, and regional storm-water drainage study projects. Project tasks included developing contract drawings and specifications for the removal of soil stockpiles, interacting with regulatory agencies, preparing construction cost estimates for water treatment equipment, developing public education materials, and hydrologic and hydraulic modeling of interjurisdictional watersheds.

In October 2001, I accepted a position with NTH Consultants, Ltd. ("NTH") in Lansing, Michigan. Throughout my career at NTH, I assumed increasing levels of responsibility from staff engineer, to assistant project engineer, and to project engineer on a variety of environmental and civil projects. Projects included due diligence assessments, subsurface explorations, underground storage tank ("UST") removal and closure, and risk-based contaminant exposure evaluations. More specifically, I managed and performed numerous Phase I Environmental Site Assessments ("ESAs") in accordance with American Society for Testing and Materials standards and United States Environmental Protection Agency All Appropriate Inquiry. Based on the Phase I ESA results, I planned and completed Phase II ESAs to characterize and delineate the horizontal and vertical extents of contamination. When appropriate, Baseline Environmental Assessments and due-care plans were prepared in accordance with Michigan Department of Environment, Great Lakes and Energy ("EGLE") guidelines. I have remediated and closed several USTs. I also have extensive construction management experience, including bid specification package development, trade contractor procurement and management, field oversight of construction and demolition projects, and associated documentation and report preparation.

After nine years in consulting, I accepted a position at Consumers Energy in August 2008. I was initially hired to serve as the project engineer and construction manager for the Little Traverse Bay Environmental Project. In this role, I managed the design and implementation of remedial strategies to address water impacted by cement kiln dust that was entering Little Traverse Bay. Some of the specific responsibilities included managing the project reserve, serving as the day-to-day interface with regulators, maintaining compliance with the final agreement with the State of Michigan, and interfacing with the impacted stakeholders. I also held the overall responsibility for project permitting, the adequacy of engineering design, selection of the contractor(s), project scopes, schedules, and budgets.

In January 2014, I became supervisor of the Risk Management group within the Environmental Compliance, Risk Management & Governance section of the Environmental and Laboratory Services Department. In this role, I became familiar with the status of the 23 Manufactured Gas Plant ("MGP") sites being managed by the Company. I served as the technical resource to the project managers and assisted with aligning the direction of the MGP Program. In January 2015, I became the Director of the Environmental Compliance, Risk Management & Governance section of the Environmental and Laboratory Services Department. The Environmental and Laboratory Services Department is now the Environmental Quality and Sustainability Department.

Q. What are your responsibilities as Director of Environmental Compliance, Risk Management & Governance?

A. As Director of Environmental Compliance, Risk Management & Governance, I am responsible for Environmental Compliance Assurance (corporate-wide environmental management system implementation), Environmental Risk Management (assessing and mitigating corporate environmental risks), and Environmental Governance to help ensure the Company maintains its strong record of excellent environmental stewardship. An integral part of the Environmental Risk Management function includes planning, directing, and controlling the investigation and remediation/risk management at former MGP sites and Comprehensive Environmental Response, Compensation, and Liability Act ("CERCLA" or "Superfund") sites where Consumers Energy is a responsible party. My section also supports the natural gas and electric operating organizations of Consumers Energy regarding the investigation and remediation of environmental contamination. The Risk Management section is also responsible for conducting environmental due diligence assessments for the acquisition, sale, lease, and licensing of Consumers Energy property.

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

A. Yes, I provided testimony in Case Nos. U-17882, U-18124, U-18424, U-20322, U-20650, U-21148, and U-21308.

Q. Are you a member of any professional societies or organizations?

A. Yes. I represent Consumers Energy on the MGP Consortium. The MGP Consortium is discussed later in my testimony.

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

A. The purpose of my testimony is to: (i) identify the former MGP sites at which Consumers Energy has a present or former ownership interest; (ii) discuss environmental requirements for investigation and remediation by Consumers Energy at these sites; (iii) identify and describe expenditures for environmental response activities at these sites that the Company is seeking approval to recover in this Commission case; and (iv) address the prudency of these expenditures.

Q. How is your direct testimony organized?

A. I will discuss the environmental remediation at Consumers Energy's former MGP sites in Sections I through IV of my direct testimony. In Section I of my direct testimony, I will identify and provide information regarding the MGP sites Consumers Energy has identified where it has a present or former ownership interest. In Section II of my direct testimony, I will discuss reasons that Consumers Energy is undertaking environmental investigation and remediation activities at these sites. In Section III of my direct testimony, I will discuss costs and the prudency of the costs. In Section IV of my direct testimony, I will discuss investigation, remediation activities, and overall progress at MGP sites. The accounting and ratemaking treatment for the MGP-related costs which I identify will be discussed by Company witness Matthew J. Foster.

Q. Are you sponsoring any exhibits?

A. Yes. I am sponsoring the following exhibits:

Exhibit A-105 (HMP-1)	Manufactured Gas Plant Sites Information; and
Exhibit A-106 (HMP-2)	MGP Environmental Response Cash Outflows – January 2023 to December 2023 by Phase & Site.

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

A. Yes. These exhibits were prepared by me or under my supervision.

Q. Please summarize your direct testimony.

A. Consumers Energy has identified 23 sites that formerly housed MGPs at which it has a present or former ownership interest. Reasonable and typical industry practices during the MGP era resulted in environmental contamination that is unacceptable under current environmental standards and laws. Consumers Energy has incurred, and will continue to incur, costs related to investigation and remediation of MGP sites. Costs related to investigation and remediation of MGP sites that Consumers Energy is seeking approval of in this case total approximately $2.3 million that will be deferred (amortized) over 10 years, and approximately $1.1 million in non-deferred (operating and maintenance ("O&M")) dollars. The split in costs will be discussed further in Section III of my testimony. These costs are reasonable and prudent, as discussed later in my testimony.

<u>SECTION I – Information on MGP Sites</u>

Q. How many MGP sites has Consumers Energy identified where it has a present or former ownership interest?

A. Consumers Energy has identified 23 sites that formerly housed MGPs at which it has a present or former ownership interest. These sites are listed on Exhibit A-105 (HMP-1). Gas was manufactured from these locations for various periods during the late 1800's until the 1950's when the last MGP was retired. The 23 sites were acquired or built by Consumers Energy between 1917 and 1934 on behalf of the Company's customers. Predecessor companies were either acquired by Consumers Energy or no longer exist.

Q. Please describe Exhibit A-105 (HMP-1).

A. Exhibit A-105 (HMP-1) provides a summary of site information for each of the 23 former MGP sites, listing: (i) location; (ii) approximate size of the site in acres; (iii) estimated peak plant capacity; (iv) date the plant was acquired or built by Consumers Energy; (v) date natural gas arrived; (vi) date put on standby status; (vii) when the plant was retired; (viii) when the holder (the MGP storage tank) was retired; (ix) the current property owners; (x) the current property use; and (xi) the current site status.

Q. What was the role of MGPs?

A. MGPs were formerly an integral part of gas utility service. Prior to the availability of natural gas, gas was manufactured. By the end of the 19th century, manufactured gas was widely used for lighting, heating, and cooking. As natural gas became available, it replaced manufactured gas as a base fuel. Even after natural gas became available, maintaining the ability to manufacture gas on a stand-by basis was viewed as important. At most of Consumers Energy's sites, after natural gas replaced manufactured gas, the plants retained their ability to manufacture gas for use in the event of gas shortages. In addition, the MGP storage tanks, often referred to as holders, were used to store natural gas.

SECTION II – Need for Environmental Investigation and Remediation

Q. Why is Consumers Energy undertaking environmental investigation and remediation activities at former MGP sites?

A. The levels of environmental awareness have increased significantly since the time when MGPs were operated. During MGP operations, the manufacture of gas resulted in various by-products which are now recognized as being environmentally harmful. Consumers Energy has discovered soil and/or ground/surface water contamination at all 23 of the former MGP sites during remedial investigations. Under current environmental standards, Consumers Energy will incur cleanup costs at all of the sites.

The costs of environmental investigation and remediation with respect to former MGP sites are necessary and ongoing costs of doing business which were not, and could not have been, anticipated during the time MGPs were in operation. Awareness of the environmental risk associated with these by-products did not exist during the MGP era. The costs of investigation and remediation are prudent expenditures that are based on public policy considerations of protecting the environment and natural resources of the State to help ensure the quality of life that customers desire. These costs are unavoidable and do not arise out of any failure to meet standards at the time the plants were in operation.

Q. How will site remediation requirements be determined for the former MGP sites in Michigan?

A. The overall framework for environmental response activities is provided by several statutory enactments. In 1980, Congress enacted the CERCLA, commonly referred to as Superfund, which required potentially responsible parties to investigate and remediate various wastes. In 1982, the Michigan Environmental Response Act ("Act 307") was enacted. In 1990, the State of Michigan passed amendments to Act 307, which established a state program similar to the federal Superfund law, although broader in scope. In 1994, additional amendments were made and Act 307 was recodified as Part 201 of Act 451 ("Part 201"), the Michigan Natural Resources and Environmental Protection Act, MCL 324.20101 *et seq*. Part 201 provides the primary framework for investigation and remediation of Consumers Energy's former MGP sites. EGLE oversees Michigan's Part 201 Program. As Director of Environmental Compliance, Risk Management & Governance, I am responsible for the Company's primary interface with EGLE on Part 201 issues.

Q. What EGLE division administers Michigan's Part 201 Program?

A. EGLE's Remediation and Redevelopment Division administers programs that facilitate the cleanup and redevelopment of sites of environmental contamination in Michigan. This includes the responsibility to oversee Michigan's Part 201 Program. Among other things, it oversees and provides information to support cleanup of contaminated sites by responsible parties, initiates enforcement action when voluntary compliance cannot be achieved, and recovers State cleanup funds from liable parties. Administrative Rules, Operational Memorandums, and Generic Cleanup Criteria are provided by EGLE. A responsible party is obligated to diligently pursue cleanup at contaminated sites to be compliant.

Q. Who are responsible parties under Part 201?

A. Under Part 201, those liable for response activity costs include: (i) the owner or operator of a facility, if the owner or operator is responsible for an activity causing a release or threat of release; and (ii) the owner or operator of a facility at the time of disposal of a hazardous substance, if the owner or operator is responsible for an activity causing a release or threat of release. Under certain circumstances, others can also be liable for response activity costs.

A party may be liable under Part 201 even though the act causing environmental contamination was lawful and reasonable at the time. Any potentially responsible party may be held liable for the entire cost of investigation and remediation of a site. Part 201 states that it applies regardless of whether the release or threat of release of a hazardous substance occurred before or after the effective date of Part 201.

Q. What is a utility's responsibility at a former MGP site that it owned or operated?

A. Part 201 requires that when a liable owner or operator of a facility obtains information that there may be a release of a hazardous substance at a facility for which they are liable, such owner or operator must take appropriate action, including confirming the existence of the release, determining the nature and extent of the release, reporting the release to EGLE if there was a reportable quantity released, and immediately taking steps to stop any continuing release. Part 201 contains affirmative obligations to avoid exacerbation of any existing contamination. The liable owner or operator must "diligently pursue" environmental response activities, including investigation and remediation, and ultimately address all contaminants associated with the site. Consumers Energy has been the owner or operator for all the former MGP sites listed on Exhibit A-105 (HMP-1) and currently owns all or portions of most of the former MGP sites listed.

EGLE has responsibility to oversee and coordinate all activities required under Part 201. EGLE is authorized by Part 201 to request or order remediation by one or more responsible parties or to undertake response activities and to recover costs incurred from responsible parties later. Each year, EGLE publishes a list of Michigan Sites of Environmental Contamination ("Part 201 Inventory of Facilities"). There are currently about 17,862 sites of environmental contamination listed on the Part 201 Inventory of Facilities. All 23 Consumers Energy former MGP sites are on the Part 201 Inventory of Facilities.

Q. Has Consumers Energy identified any former MGP owners or any predecessor or successor companies of such owners for the 23 sites at which Consumers Energy has a present or former ownership interest?

A. No. A prior search for former MGP owners or any predecessors or successor companies of such owners for the 23 sites did not find any in existence today. Hence, no other potentially responsible parties have been identified.

Q. Does a site have to be listed on the Part 201 list in order for an owner or operator to be obligated to undertake environmental response activities or to incur response costs?

A. No. EGLE is authorized to require that environmental response activities be undertaken by a responsible party even if the site is not listed on the Part 201 list. In addition, discovery of contamination related to MGPs at or near a former MGP site can require an owner or operator to undertake response activities.

Q. What is Consumers Energy's strategy for the management of the former MGP sites?

A. Consumers Energy's strategy is to minimize the impact from the former MGP sites on human health and safety, as well as to minimize any damage to the surrounding natural resources, in the most cost-effective way possible. The strategy for the management of the former MGP sites is based on the environmental risk that these sites pose to human health, safety, and damage to natural resources. Consumers Energy routinely assesses the environmental exposure and/or exacerbation risks at each site based on changing conditions and new information. Based on the risk assessment, response activities are prioritized, developed, designed, and implemented.

The environmental response strategy will be determined based upon the land uses and zoning at individual facilities, the environmental media involved, and the relevant exposure pathways. The key elements of an exposure pathway are a source or release of a hazardous substance, an exposure point, an exposure route, and a transport mechanism. In developing an environmental response strategy at a particular site, the Company develops a plan to address contamination in all environmental media, including but not limited to: (i) contaminated groundwater; (ii) contaminated soils; (iii) contaminated sediments; and

(iv) vapor intrusion. Based on the media impacted and the nature of contaminant(s), remediation strategies may vary including removal, recovery, containment/barrier technologies, monitored natural attenuation, etc. Once exposure risks for all contaminants in all applicable media for all exposure scenarios are mitigated, the site may be eligible for No Further Action ("NFA").

Q. Is it possible under current regulations to obtain total closure status for an environmentally contaminated former MGP site?

A. No. Part 201 of the Natural Resources and Environmental Protection Act, 1994 Public Act 451, was revised in 2010 by adding a regulatory mechanism that allowed for NFA at a contaminated site if certain conditions are met. However, NFA does not mean there is a total closure. Rather, NFA is a regulatory status that allows the site to maintain a "negotiated status quo," that requires no or minimal ongoing remedial actions. It is the responsibility of the owner/operator to maintain the agreed upon conditions of the NFA agreement such as due care, groundwater monitoring, and O&M of control technologies. If any of the conditions are not maintained, or there is a change in conditions, the NFA status becomes invalid. While NFAs acknowledge remedial actions performed and what exposures/risks are still present at the sites, approvals of these actions does not eliminate present or future liabilities or close the site.

Q. Who is financially responsible if the negotiated status is not maintained and work needs to be performed?

A. Typically, the party that commits the noncompliance will ultimately be financially responsible.

Q. Is Consumers Energy looking into the possibility of obtaining NFA status at former MGP sites?

A. Yes. Consumers Energy is actively pursuing NFA at several former MGP sites. It should be noted that the Company does not consider a site eligible to pursue NFA status unless contamination in all environmental media is addressed. Consumers Energy submitted and obtained NFA status for the following former MGP sites:

- Ionia – 2013
- Grand Ledge (site proper) – 2016
- Marshall – 2019
- Mt. Clemens (site proper) – 2021
- Royal Oak – 2021
- Alpena – 2021
- Bay City (site proper) - 2022
- St. Johns (site proper) – 2023

An NFA was submitted for the Sault Saint Marie MGP site but was ultimately withdrawn due to lack of property owner signature on the necessary restrictive covenant. A Certificate of Completion was obtained for this site in 2021.

Consumers Energy has also initiated discussions with EGLE regarding several MGP sites that potentially may qualify for NFA status. This is discussed later in my testimony. Due to the complexity of the remediation that needs to be addressed and current status of remediation, it would not be efficient at present to seek NFA status at all of the sites. In some cases, it may be more practical to obtain a Certificate of Completion (described below) due to site restrictions/liability concerns.

Q. Does NFA mean that there will be no additional costs on these sites?

A. No. There will be costs associated with these projects even after they achieve NFA status. These costs may include routine sampling, preparing and submitting reports, some O&M tasks, due care, etc. These long-term, post-NFA costs may be significant.

Q. What is a Certificate of Completion?

A. A Certificate of Completion is a written response provided by EGLE that a response activity has been completed in accordance with the applicable requirements of Part 201 and is approved by EGLE.

Q. What are the benefits of a Certificate of Completion?

A. A Certificate of Completion provides EGLE concurrence that response activities were performed at a site as proposed. However, there are no requirements for either Post Closure Agreements or financial assurance with a Certificate of Completion.

Q. Has the Company received any Certificates of Completion?

A. Yes. The Company received a Certificate of Completion from EGLE in July 2019 for the Sediment Response Action project at the Flint East MGP, and for the Sault Saint Marie site as discussed earlier.

Q. What is a Post Closure Agreement?

A. It is an agreement that may be required by EGLE based on activities needed following NFA approval. The agreement is between EGLE and the submitting entity. It contains terms regarding future liabilities and potential reopeners of the NFA document.

SECTION III – Costs and Prudence

Q. What levels of expenditures are attributable to environmental response activities at the 23 former MGP sites?

A. The level of environmental response expenditures for the period January 2023 through December 2023 totals approximately $2.3 million in deferred (amortized) dollars, and $1.1 million in non-deferred dollars for the period of October 1, 2024 through September 30, 2025.

Q. Do these amounts include Consumers Energy's Project Management ("PM") costs?

A. No. As recommended by the Commission Staff ("Staff") in Case No. U-14547, the Company has excluded PM and associated costs from the MGP Environmental Response Cash Outflows.

Q. Please describe what types of costs were excluded from the MGP Environmental Response Cash Outflows.

A. The types of costs excluded are costs of Consumers Energy employees and associated expenses such as Labor, Lab Services, Fleet, Real Estate, business expenses, and computer charges. Those costs are included as O&M expense. In addition, Consumers Energy has excluded professional organization membership costs and lawn maintenance costs from the MGP Environmental Response Cash Outflows shown on Exhibit A-106 (HMP-2). Membership fee expenditures and lawn care expenditures are included instead as O&M expenditures.

Q. Do the MGP Environmental Response Cash Outflows you are presenting in this rate case include professional membership fees?

A. No. As mentioned earlier, professional membership fees, specific to MGP remediation operation, are not included in the MGP Environmental Response Cash Outflows shown on Exhibit A-106 (HMP-2). However, professional membership costs are included in the MGP Expenditures Not Deferred included in the O&M portion of the rate case. The two specific professional memberships are the Utility Solid Waste Advisory Group ("USWAG") and MGP Consortium.

Membership in the USWAG is directly related to helping Consumers Energy to evaluate environmental investigation and remediation response activities and to identify the most cost-effective MGP investigation and remediation measures that are protective of human health and the environment. The USWAG provides a technical resource for management of waste streams from the remediation of MGP sites allowing for protection of natural resources while minimizing unnecessary costs.

The MGP Consortium includes members from various utility companies in the nation who are currently managing MGP sites as part of their liability management. The MGP Consortium is designed to discuss and share knowledge or project experience between owners/operators of former MGP sites. Membership in the MGP Consortium has facilitated discussions about general MGP PM, remediation technology evaluation, remediation technology application, lessons learned, public relations, public policy trends, and vendor evaluations. These memberships have helped Consumers Energy in its evaluation of technical, regulatory, legislative, and policy issues related to the investigation and remediation of former MGP sites.

Q. Why have dollars been separated as non-deferred?

A. In Case No. U-20650, the Company agreed in rebuttal testimony to include routine monitoring and reporting and regulatory/legal requirements of Post Closure Agreements or other mechanisms after receipt of NFA, Remedial Action Plan, or Certificate of Completion approval as non-deferred (O&M) expenditures. This change began with the test year for Case No. U-21308 which was October 1, 2022 through September 30, 2023. These costs are in addition to the direct management or other O&M costs previously discussed.

Q. What is the amount of the non-deferred MGP expenditures?

A. The non-deferred MGP expenditures is $1.1 million. These expenses are covered in Company witness Foster's Exhibit A-48 (MJF-5).

Q. Were MGP environmental response activity costs incurred prior to January 2023?

A. Yes. Costs for environmental response activities for periods prior to January 2023 were reviewed and audited by Staff in Case No. U-21308 and earlier cases; therefore, these costs have not been included on Exhibit A-106 (HMP-2) in the current case.

Q. At how many of the sites will Consumers Energy incur deferred (amortized) costs during the period January 2023 through December 2023?

A. Costs will be incurred at 14 sites.

Q. Why were deferred costs not incurred at all 23 MGP sites?

A. As the sites reach NFA status or point of minimal activity based on current site conditions, the Company does not necessarily use consultants for the remaining activities. The Company will use internal staff to complete the necessary obligations and reporting to reduce the program costs.

Q. Please explain Exhibit A-106 (HMP-2).

A. Exhibit A-106 (HMP-2) shows the cash outflows for environmental investigation and remediation during the period January 2023 through December 2023 for each MGP site. Costs are shown by phase and in total for all 23 MGP sites.

Q. How were these costs developed?

A. Costs shown on Exhibit A-106 (HMP-2) include projected costs. Costs for January through December 2023 are projected costs based on the work scope developed for the sites and the long-term strategy.

Q. How did you determine the costs for activities that have not yet occurred?

A. The cost for each activity is based upon the strategy identified to move the site toward NFA/Certificate(s) of Completion. The strategies have been developed based on past experience at Consumers Energy sites and other sites, overall knowledge, site background, site use, site investigations, remedial investigations, and feasibility study evaluations. Based on all this information and data, we determine, with assistance from the consultants involved with each of these sites, how to move sites forward in the most prudent way possible while maintaining compliance with EGLE regulations and requirements.

Q. Why are the costs incurred different at different sites?

A. Environmental response costs are influenced by a number of site-specific factors. Costs can vary significantly depending on: (i) the nature and extent of contamination; (ii) size of the site; (iii) geology of the site; (iv) presence of surface water and depth of groundwater; (v) present and future use of the site; and (vi) types of remedial action. The costs on the exhibit differ due to site-specific factors.

Q. What MGP environmental expenditures are you seeking approval for in this case?

A. Consumers Energy is seeking approval in the current case for deferred (amortized) MGP environmental response expenditures from January 2023 through December 2023. The Company is also seeking approval of non-deferred (O&M) recovery of MGP expenditures for the test year that covers October 1, 2024 through September 30, 2025.

Q. Are the expenditures that Consumers Energy is seeking recovery for in this case reasonable and prudent?

A. Yes. The need for environmental investigation, remediation, and the parameters for cleanup are mandated and defined by the state and federal government. The costs of investigation and remediation are not based on any imprudence, but upon public policy considerations of protecting the environment and natural resources of the State on behalf of the customers we serve. MGP site investigation and remediation costs are legitimate and necessary costs of doing business. The costs incurred were costs for activities that are necessary under current environmental regulations and overseen by EGLE. The need for incurring such costs is based upon current environmental awareness, not any fault on the part of the operator of the former MGP facilities.

Q. Does the Company coordinate site activities with EGLE?

A. Consumers Energy has taken a proactive role with EGLE. By taking a proactive role, Consumers Energy has had a better opportunity to participate in decisions involving investigation and remedial actions than if EGLE were to order remediation or to undertake remediation itself. Consumers Energy has undertaken response activities in an efficient manner to minimize costs consistent with health and safety considerations. Consumers Energy has sought approval from EGLE of the most cost-effective remediation, which is protective of human health and the environment, as allowed by law. The expenditures which Consumers Energy is seeking to recover in this case are reasonable and prudent.

Q. Does the Company use competitive bidding as a means of controlling costs?

A. Yes. Current Company policies require competitive bidding for purchases of materials and/or services initially over $100,000, except for emergencies or where only one vendor can supply the goods or services. For smaller scale response activities, such as drilling and small disposal activities, the site consultant handles the initial bidding and ensures the contracted costs are reasonable. For larger activities, the Company competitively bids the project. If competitive bids are not sought, the Company documents reasons why the competitive bidding process was not used. During the competitive bidding process, the qualifications of each contractor and subcontractor are reviewed to determine if they have the resources and expertise to complete the tasks on which they are bidding. The Company also evaluates contracting strategies (e.g. time and materials, lump sum, not to exceed, etc.) to determine which will provide the most value and reduce risks during the projects.

Q. Please describe how the consultants used were selected.

A. The main consultants for each site were selected using a bidding process. Consultants who were interested bid for each MGP site separately. As part of the competitive bidding process, the qualifications of each consultant were reviewed to determine if they had the resources and expertise to complete the projects on which they were bidding. The Company selected six main consultants for the 23 sites. Using the same consultant for more than one site increases efficiency and improves consistency. Limiting the consultants to fewer than all sites helps assure that they will be able to complete the work in a timely fashion.

Q. Please discuss Environmental Response Cash Outflows at the MGP sites.

A. The majority of the Environmental Response Cash Outflows shown on Exhibit A-106 (HMP-2) are for remedial actions. Remedial action costs were incurred at 5 of the 23 sites. The remedial action costs incurred include collection of data supporting remedial action and response activities such as: (i) source-area impacted soil removal; (ii) operation of existing in-site remediation systems; (iii) groundwater monitoring; (iv) treatability studies; and (v) other activities intended to resolve containment issues. The environmental response costs also include activities related to Remedial Investigations, Feasibility Studies, and NFA. The NFA phase was previously divided into pre-NFA and post-NFA. Pre-NFA tasks included EGLE negotiations, preparation of NFA reports, property surveys, and recording use restrictions, etc. Post-NFA tasks are now included in the non-deferred O&M dollars, and include activities such as monitoring, operation, maintenance, due care, and reporting obligations. Response activities are discussed in more detail later in my testimony.

SECTION IV – Response Actions

Q. What types of environmental response activities may be required at a former MGP site?

A. The sequence, timing, and magnitude of response activities vary from site to site depending upon the size of the site, the degree of environmental contamination, current and potential future land use, the degree of enforcement discretion exercised by EGLE, the media impacted, and other site-specific factors. However, the usual sequence of environmental response activities which would typically be undertaken at a former MGP site would be:

1. Site Investigation;
2. Remedial Investigation;

3. Interim Response Activities;
4. Feasibility Study;
5. Remedial Action;
6. NFA; and
7. O&M.

Q. Please briefly describe each of these activities.

A. **Site Investigation:** A Site Investigation involves research of site-related information such as available historical records, past and current site uses, topographical maps, engineering drawings, and a review of potential sources of environmental contamination. A site visit is also usually done during a Site Investigation to relate the information collected by the records search to current site conditions and to conduct a visual inspection for any obvious signs of MGP contamination.

Remedial Investigation: The purpose of a Remedial Investigation is to define the nature and extent of contamination at a site. Consumers Energy worked with EGLE to reach a common understanding on facility prioritization criteria as it relates to risk assessment and exposure pathways. In addition, Consumers Energy sought input, review, and concurrence from EGLE on major remedial investigation work plans. This collaborative approach allowed Consumers Energy to be better responsive to EGLE concerns and issues in developing and implementing work plans.

The Remedial Investigation includes the collection and analysis of samples of surface soils, subsurface soils, groundwater, and/or surface water. Limited field screening measurements of soil, gas, and air samples may also be conducted. These samples are analyzed for chemicals of concern that are typical of MGP by-products and wastes. Remedial Investigations typically generate solid and liquid waste, called Investigation Derived Waste, that must be disposed per state and federal regulations.

<u>Interim Response Activities</u>: Interim Response Activities may be required if the results of the Remedial Investigation or other information indicates a need to abate a threat to human health or to the environment on an interim basis while further investigation occurs. Examples of the types of Interim Response Activities which may occur for contaminated soils include erecting a fence, installing drainage controls and stabilization, capping, removal, and treatment or disposal of the grossly contaminated soils to eliminate direct-contact hazards and to prevent further migration. Free phase product recovery is also considered as an Interim Response Activity. Interim Response Activities can also generate solid and liquid waste that must be disposed per state and federal regulations.

<u>Feasibility Study</u>: The purpose of the Feasibility Study is to develop, evaluate, and select which of several remedial action alternatives, including no action, may be appropriate. The Feasibility Study involves identifying appropriate remedial technologies, determining the applicability of the technologies to a specific site, evaluating the implementability and total cost of operations, and developing a cost benefit analysis.

<u>Remedial Action</u>: Remedial Action includes, but is not limited to, cleanup, removal, containment, isolation, destruction, or treatment of a hazardous substance released or threatened to be released. Some remedial actions may require operation of active remediation systems, which require significant ongoing activities along with performance monitoring. Remedial actions may generate significant solid and liquid waste that must be disposed per state and federal regulations.

<u>NFA</u>: Once Remedial Action is complete, and the applicable cleanup criteria are achieved, then the project may be eligible to seek NFA status. The NFA is usually associated with some land and resource use restrictions along with long-term monitoring and/or due-care obligations. As discussed earlier in my testimony, it is not possible under current regulations to obtain total closure status for the former MGP sites. The NFA activities may include NFA report preparation, negotiations with EGLE and other stakeholders, developing and recording site surveys, restrictive covenants, etc. Preparation of Certificate(s) of Completion will also be included as NFA activities.

O&M: Activities performed as O&M may include routine monitoring data collection, due-care activities, system operation and maintenance, and associated reporting. The O&M activities may be required indefinitely.

Q. What are some examples of environmental response activities that have either been completed during the January 2023 through December 2023 timeframe or are currently underway?

A. Examples of projects that have been completed or are underway include the following:

- Alma MGP site – Annual groundwater sampling was performed and the City of Alma's well ordinance was discussed with EGLE as a possible institutional control for the site.

- Bay City MGP site – Received EGLE's approval of the NFA for the MGP area north of 9th Street in September 2022. Submitted a draft NFA to EGLE for MGP area south of 9th Street. Working with stakeholders to execute and record a restrictive covenant covering the area south of 9th Street and once complete, will submit final NFA for EGLE approval.

- Charlotte MGP site – Drafted a groundwater use ordinance and coordinated review and approval by both EGLE and the City of Charlotte. The ordinance was approved by the City Council in August 2023. The ordinance prohibits the installation of groundwater wells in the area of the former MGP and eliminates the need to restrict each property individually.

- Flint Court MGP site – Annual groundwater sampling was performed. Initiated quarterly vapor intrusion sampling of the former by-products building to assess potential vapor intrusion pathway. Conducted soil and groundwater sampling to aid in evaluations and potential revisions to the draft NFA.

- Flint East MGP site – Annual groundwater sampling was performed. Conducted inspections and bathymetry evaluations within sediment cap reach.

Initiated groundwater discharge permitting for drain tile operation (if required in the future). Began planning vapor intrusion assessment near the Rec Center building. Continued to provide review comments on the dam removal design (planned in 2026) as it impacts the river sediment removal work that was performed in 2017.

- Kalamazoo MGP site – Continued sampling new monitoring wells to evaluate groundwater in-contact with the research / office building structure to determine the applicability of the vapor intrusion pathway. Installed and sampled sub-slab points in the research / office building to evaluate the vapor intrusion pathway evaluation. Began evaluating use of active and/or passive air sampling to evaluate vapor intrusion pathway for the on-site power plant. Began drafting of the NFA document.

- Jackson MGP site – Began preparing a Comprehensive Project Summary Report.

- Manistee MGP site (ongoing) – Performed quarterly groundwater sampling at the former relief holder ("FRH") site. Conducted vertical aquifer profile sampling to evaluate the dissolved phase plume at the FRH site. Submitted the Operational site NFA to EGLE for review and approval. Coordinating with stakeholders to execute and record restrictive covenant covering the Operational site.

- Owosso – Annual groundwater sampling was performed. Soil and groundwater sampling was performed to add offsite evaluations. Purchased two of the three impacted residential homes.

- Plymouth MGP site – Annual sampling was performed at the site. A new consultant was retained to evaluate the current monitoring well network and the response plan for the site.

- Royal Oak MGP site – Provided well abandonment documentation to EGLE. Performed annual site walk.

- St. Johns MGP site – Responded to several questions and comments from EGLE on the NFA report and proposed restrictive covenant ("RC"). However, EGLE elected to let the formal review period expire and therefore, the NFA is approved per 324.20114d(9). The RC will be recorded and monitoring wells abandoned by the end of 2023.

Additionally, investigations, routine monitoring, reporting, NFA, and O&M activities were also conducted.

Q. Does the Company need a formal approval by EGLE to implement response activities?

A. No. A formal approval is not required to implement response activities. However, Consumers Energy has taken a proactive role with EGLE to provide an opportunity to collaborate with EGLE regarding decisions involving investigation and remedial actions. This approach helps minimize the possibility of EGLE issuing a remediation order or undertaking the remediation itself at Consumers Energy's expense. We believe that our continuous involvement with EGLE and the collaborative approach results in cost-effective remediation that is protective of human health and the environment as required by law. This collaborative approach is carried out both through formal and informal means.

Q. Can you summarize any recent approvals that Consumers Energy has received from EGLE?

A. Based on the activities completed from January 1 through August 30, 2023, the St. Johns NFA was administratively approved in May 2023.

Q. How does the Company respond to EGLE requests for inclusion of additional parameters in testing or any other requests at a site?

A. The Company has highly trained remediation experts that will review the request, evaluate the value provided by the request, and discuss this evaluation with the EGLE. Inclusion of additional parameters or other requests suggested by the EGLE can significantly increase costs. In addition, practical and technical limitations must be considered. If these are not typical for the type of remedial action underway, the Company will attempt to determine if there is an alternative or more cost-effective way to address EGLE's concerns.

As mentioned earlier in my testimony, Consumers Energy has taken a proactive role with EGLE to provide an opportunity to collaborate with EGLE regarding decisions involving investigation and remedial actions. This approach helps minimize the possibility of EGLE issuing a remediation order or undertaking the remediation itself at the Company's expense. Consumers Energy seeks approval from EGLE of the most cost-effective remediation that is protective of human health and the environment as required by law.

Q. Please describe soil and/or groundwater remediation systems in operation.

A. Currently, there is one active groundwater remediation system at the MGP sites. The Cross Street site remediation system consists of a groundwater air sparge system, installed in 2011. This system was deactivated in 2019 to evaluate groundwater conditions and allow for in-situ soil stabilization ("ISS") of the impacted soils near the former holder location. The system remained off until the spring of 2022. At this time the system is operational to control some fluctuating concentrations in monitoring wells outside of the ISS area. This system is maintaining groundwater surface water interface compliance while the source of the fluctuating concentrations is evaluated.

Q. Does the Company have any inactive soil and/or groundwater remediation systems?

A. Yes. The multiphase system that consists of a Light Non-Aqueous Phase Liquid recovery system, a groundwater pump and treatment system, and a Soil Vapor Extraction and treatment system at the Jackson MGP site has been inactive since April 2016. The system is slated for decommissioning in 2024 -2025.

Q. Were there any MGP property ownership changes in the time period covered by this filing?

A. No.

Q. Are the MGP costs described in your testimony reasonable and prudent?

A. Yes, they are. They are reasonable and prudent costs of doing business.

Q. Does this conclude your direct testimony?

A. Yes.

S T A T E O F M I C H I G A N

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the application of	)	
CONSUMERS ENERGY COMPANY	)	
for authority to increase its rates for the	)	Case No. U-21490
distribution of natural gas and for other relief.	)	
	)	

DIRECT TESTIMONY

OF

HEATHER L. RAYL

ON BEHALF OF

CONSUMERS ENERGY COMPANY

December 2023

Q. Please state your name and business address.

A. My name is Heather L. Rayl, and my business address is One Energy Plaza, Jackson, Michigan 49201.

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

A. I am employed by Consumers Energy Company ("Consumers Energy" or the "Company") as a Senior Rates Analyst in the Revenue Requirement Section of the Revenue Requirements and Regulatory Affairs Department.

Q. Please state your educational background.

A. I received both a Bachelor of Arts and a Master of Business Administration degree from Michigan State University in 1993. I am also a Certified Public Accountant registered in the state of Michigan.

Q. Please describe your business experience.

A. After receiving my degrees in 1993, I have held various positions in audit, financial statement preparation and analysis, general ledger analysis, and preparation and analysis of statutory annual reports.

In 2004, I started my career at Consumers Energy as a Senior Analyst in Accounting Research and External Financial Reporting. My responsibilities included the research and documentation of numerous technical accounting topics for departmental clients, including United States Generally Accepted Accounting Principles issues, United States Securities and Exchange Commission issues, utility/regulatory issues, and the preparation and documentation of numerous disclosures in the Company's Forms 10-K and 10-Q, with a primary focus in regulatory matters.

In 2013, I joined Consumers Energy's Rates and Regulatory Affairs Department. During my tenure, I have held positions in Revenue Requirements and Rate Design as a Senior Rates Analyst.

Q. What are your job responsibilities?

A. I am responsible for conducting analyses related to the Company's revenue requirements and developing testimony and exhibits in support of proposals in regulatory proceedings before the Michigan Public Service Commission ("MPSC" or the "Commission").

Q. Have you previously testified in any proceedings before the Commission?

A. Yes. I have filed testimony in Gas Rate Case Nos. U-18124, U-18424, U-21148, and U-21308; Gas Cost Recovery ("GCR") Plan Case Nos. U-17334, U-17693, U-17943, U-18151, and U-21269; GCR Reconciliation Case Nos. U-16924-R, U-17133-R, U-17334-R, and U-17693-R; Gas Revenue Decoupling Case No. U-18367; Renewable Energy Plan Case No. U-18231; and Investment Recovery Mechanism Reconciliation Case No. U-20893.

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

A. The purpose of my direct testimony is to: (i) identify and support the Part I exhibits required by the Commission's Order in Case No. U-18238 ("Filing Requirements"); (ii) present Consumers Energy's revenue requirement calculation for the projected test year; and (iii) request approval of the Federal Energy Regulatory Commission ("FERC") accounting treatment for first-time and one-time maximum allowable operating pressure ("MAOP") retesting costs.

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

A. My direct testimony is divided into three sections:

Section I:	Historical Year
Section II:	Projected Test Year
Section III	Accounting Treatment for MAOP Retesting Costs to Comply with New Federal Safety Standards

Q. Please describe the revenue requirements determination.

A. In compliance with the Filing Requirements, my direct testimony presents the revenue requirement for the historical year, explains the development of the revenue requirement for the projected test year, and reconciles the historical and projected test years. The Company demonstrates in this instant case that it requires a rate increase to its gas tariffs in order to earn a just and reasonable return.

Q. Are you sponsoring any exhibits?

A. Yes. I am sponsoring the historical year exhibits identified in Section I of my direct testimony and the projected test year exhibits identified in Section II of my direct testimony.

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

A. Yes.

I. <u>HISTORICAL YEAR</u>

Q. What is the historical year used in your exhibits and supporting direct testimony?

A. Calendar year 2022 is the historical year in the instant case.

Q. Please identify the exhibits that you are sponsoring to comply with the Commission's Filing Requirements for the historical year.

A. The following exhibits are being submitted to satisfy the historical year Filing Requirements:

Exhibit A-1 (HLR-1)	Schedule A-1	Revenue Deficiency (Sufficiency) for the Historical Year Ended December 31, 2022;
Exhibit A-1 (HLR-2)	Schedule A-2	Historical Financial Metrics - Gas Results Only;
Exhibit A-2 (HLR-3)	Schedule B-1	Rate Base for the Historical Year Ended December 31, 2022;
Exhibit A-2 (HLR-4)	Schedule B-2	Total Utility Plant for the Historical Year Ended December 31, 2022;
Exhibit A-2 (HLR-5)	Schedule B-3	Depreciation Reserve and Other Deductions for the Historical Year Ended December 31, 2022;
Exhibit A-2 (HLR-6)	Schedule B-4	Working Capital for the Historical Year Ended December 31, 2022;
Exhibit A-2 (HLR-7)	Schedule B-5	13-Month Average Balance Sheet Summary for the Historical Year Ended December 31, 2022;
Exhibit A-2 (HLR-8)	Schedule B-6	Point-in-Time Balance Sheet Summary for the Historical Year Ended December 31, 2022;
Exhibit A-3 (HLR-9)	Schedule C-1	Adjusted Net Operating Income for the Historical Year Ended December 31, 2022;
Exhibit A-3 (HLR-10)	Schedule C-2	Calculation of the Revenue Conversion Factor for the Historical Year Ended December 31, 2022;
Exhibit A-3 (HLR-11)	Schedule C-3	Operating Revenues for the Historical Year Ended December 31, 2022;
Exhibit A-3 (HLR-12)	Schedule C-4	Cost of Gas Sold for the Historical Year Ended December 31, 2022;
Exhibit A-3 (HLR-13)	Schedule C-5	Other Operation and Maintenance Expenses for the Historical Year Ended December 31, 2022;

Exhibit A-3 (HLR-14)	Schedule C-5.1	Other Operation and Maintenance Expenses by Witness for the Historical Year Ended December 31, 2022;
Exhibit A-3 (HLR-15)	Schedule C-6	Depreciation and Amortization Expenses for the Historical Year Ended December 31, 2022;
Exhibit A-3 (HLR-16)	Schedule C-7	General Taxes for the Historical Year Ended December 31, 2022;
Exhibit A-3 (HLR-17)	Schedule C-8	Federal Income Taxes for the Historical Year Ended December 31, 2022;
Exhibit A-3 (HLR-18)	Schedule C-9	State Income Taxes for the Historical Year Ended December 31, 2022;
Exhibit A-3 (HLR-19)	Schedule C-10	Other (or Local) Taxes for the Historical Year Ended December 31, 2022;
Exhibit A-3 (HLR-20)	Schedule C-11	Allowance for Funds Used During Construction for the Historical Year Ended December 31, 2022;
Exhibit A-3 (HLR-21)	Schedule C-12	Income Tax Effect of Interest for the Historical Year Ended December 31, 2022;
Exhibit A-3 (HLR-22)	Schedule C-13	Interest Synchronization Adjustment for the Historical Year Ended December 31, 2022;
Exhibit A-4 (HLR-23)	Schedule D-1	Overall Rate of Return Summary for the Historical Year Ended December 31, 2022;
Exhibit A-4 (HLR-24)	Schedule D-2	Cost of Long-Term Debt (Excluding Securitization) for the Historical Year Ended December 31, 2022;
Exhibit A-4 (HLR-25)	Schedule D-3	Cost of Short Term Debt for the Historical Year Ended December 31, 2022;

Exhibit A-4 (HLR-26)	Schedule D-4	Cost of Preferred Stock for the Historical Year Ended December 31, 2022; and
Exhibit A-4 (HLR-27)	Schedule D-5	Cost of Common Equity for the Historical Year Ended December 31, 2022.

Q. How are these exhibits organized?

A. The exhibits are organized into schedules that present the development of the revenue deficiency (Schedule A), rate base (Schedule B), adjusted net operating income ("NOI") (Schedule C), and rate of return (Schedule D).

Q. Who is sponsoring the historical year Schedule E exhibits?

A. The historical year Schedule E exhibits are sponsored by Company witness Eric J. Keaton.

Q. Please describe the Schedule A exhibits for the historical year.

A. Exhibit A-1 (HLR-1), Schedule A-1, presents the computation of the gas revenue requirement for the year ended December 31, 2022. Exhibit A-1 (HLR-1), Schedule A-1 is developed from the financial data presented in Schedules B, C, and D described below.

Exhibit A-1 (HLR-2), Schedule A-2, is a multiple page exhibit that provides financial metrics on a financial basis (pages 1 through 3) and on a ratemaking basis (pages 4 through 6) for the years 2018 through 2022. The calculation of the gas return on equity for each of these years can be found on pages 1 and 4.

Q. Please describe the Schedule B exhibits for the historical year.

A. Exhibit A-2 (HLR-3), Schedule B-1, presents the calculation of the average rate base for the historical year ended December 31, 2022. The average rate base on line 8 of Exhibit A-2 (HLR-3), Schedule B-1, is carried forward to Exhibit A-1 (HLR-1), Schedule A-1, line 1. Exhibit A-2 (HLR-4), Schedule B-2, through Exhibit A-2 (HLR-8), Schedule B-6, support the development of the various components of average rate base including net utility plant and working capital.

Q. Please describe the Schedule C exhibits for the historical year.

A. Exhibit A-3 (HLR-9), Schedule C-1, presents the calculation of adjusted NOI for the historical year ended December 31, 2022. The adjusted NOI disclosed on line 37 of Exhibit A-3 (HLR-9), Schedule C-1, is carried forward to Exhibit A-1 (HLR-1), Schedule A-1, line 2. Exhibit A-3 (HLR-10), Schedule C-2, through Exhibit A-3 (HLR-22), Schedule C-13, support the development of the various components of adjusted NOI. Schedule C data for the historical year are generally sourced to the Company's 2022 Form P-522 Annual Report. In addition, Exhibit A-3 (HLR-14), Schedule C-5.1, reconciles the historical year other operating and maintenance ("O&M") expense by account, by witness, with the other O&M expense amounts filed in the Company's 2022 Form P-522 Annual Report.

Q. Please describe the Schedule D exhibits for the historical year.

A. Exhibit A-4 (HLR-23), Schedule D-1, presents the overall rate of return summary for the historical year ended December 31, 2022. The total weighted cost of capital is shown on line 14, column (g), and is carried forward to Exhibit A-1 (HLR-1), Schedule A-1, line 4. Exhibit A-4 (HLR-24), Schedule D-2, through Exhibit A-4 (HLR-27), Schedule D-5, support the development of various components of the overall rate of return for the historical year, including debt, preferred stock, common equity, and other sources of financing.

Q. Based on your review of the historical year exhibits, was there a revenue deficiency in the historical year?

A. No. I have calculated a revenue sufficiency of $2.7 million for the historical year ended December 31, 2022.

Q. Please summarize the key findings from the historical year exhibits.

A. As presented on Exhibit A-1 (HLR-1), Schedule A-1, the key findings from the exhibits for the historical year ended December 31, 2022 are as follows:

	($ In Thousands)
Rate Base	$ 8,658,825
Adjusted NOI	$ 497,582
Overall Rate of Return	5.75%
Required Rate of Return	5.72%
Income Required	$ 495,578
Income Sufficiency	$ (2,003)
Revenue Conversion Factor	1.3391
Revenue Sufficiency	$ (2,682)

Q. Do the above results include typical ratemaking adjustments such as weather, unusual, one-time, or out-of-period items, and regulatory disallowances?

A. Yes. The historical year presentation begins with the Company's booked results and ratemaking adjustments and normalizations are recognized, where appropriate, as summarized on Exhibit A-3 (HLR-9), Schedule C-1. I will discuss the adjustments and normalizations in Section II of my direct testimony, which covers the projected test year.

II. PROJECTED TEST YEAR

Q. What is the projected test year used in your exhibits and supporting testimony?

A. In this proceeding, the projected test year is the 12-month period ending September 30, 2025.

Q. Please identify the exhibits that you are sponsoring to comply with the Commission's Filing Requirements for the projected test year.

A. The following exhibits are being submitted to support and satisfy the projected test year Filing Requirements:

Exhibit A-11 (HLR-28)	Schedule A-1	Revenue Deficiency (Sufficiency) for the Projected 12-Month Period Ending September 30, 2025;
Exhibit A-11 (HLR-29)	Schedule A-2	Financial Metrics – Ratemaking Basis – For the Projected 12-Month Period Ending September 30, 2025, Gas Results Only;
Exhibit A-11 (HLR-30)	Schedule A-3	Comparison of the Historical and Projected Revenue Requirement for the Projected 12-Month Period Ending September 30, 2025;
Exhibit A-12 (HLR-31)	Schedule B-1	Rate Base for the Projected 12-Month Period Ending September 30, 2025;
Exhibit A-12 (HLR-32)	Schedule B-2	Total Utility Plant for the Projected 12-Month Period Ending September 30, 2025;
Exhibit A-12 (HLR-33)	Schedule B-3	Depreciation Reserve for the Projected 12-Month Period Ending September 30, 2025;
Exhibit A-12 (HLR-34)	Schedule B-4	Working Capital for the Projected 12-Month Period Ending September 30, 2025;

Exhibit A-12 (HLR-35)	Schedule B-5	Capital Spending for the Projected 12-Month Period Ending September 30, 2025;
Exhibit A-13 (HLR-36)	Schedule C-1	Adjusted Net Operating Income for the Projected 12-Month Period Ending September 30, 2025;
Exhibit A-13 (HLR-37)	Schedule C-1.1	Development of Adjusted Net Operating Income for the Projected 12-Month Period Ending September 30, 2025;
Exhibit A-13 (HLR-38)	Schedule C-2	Calculation of the Revenue Conversion Factor for the Projected 12-Month Period Ending September 30, 2025;
Exhibit A-13 (HLR-39)	Schedule C-3	Operating Revenues for the Projected 12-Month Period Ending September 30, 2025;
Exhibit A-13 (HLR-40)	Schedule C-4	Cost of Gas Sold for the Projected 12-Month Period Ending September 30, 2025;
Exhibit A-13 (HLR-41)	Schedule C-5	Other Operation and Maintenance Expenses for the Projected 12-Month Period Ending September 30, 2025;
Exhibit A-13 (HLR-42)	Schedule C-5.1	Summary of Inflation and Merit Increases Included in Other Operation and Maintenance Expenses for the Projected 12-Month Period Ending September 30, 2025;
Exhibit A-13 (HLR-43)	Schedule C-6	Depreciation and Amortization Expenses for the Projected 12-Month Period Ending September 30, 2025;
Exhibit A-13 (HLR-44)	Schedule C-7	General Taxes for the Projected 12-Month Period Ending September 30, 2025;
Exhibit A-13 (HLR-45)	Schedule C-8	Federal Income Taxes for the Projected 12-Month Period Ending September 30, 2025;

Exhibit A-13 (HLR-46)	Schedule C-9	State Income Taxes for the Projected 12-Month Period Ending September 30, 2025;
Exhibit A-13 (HLR-47)	Schedule C-10	Other (or Local) Taxes for the Projected 12-Month Period Ending September 30, 2025;
Exhibit A-13 (HLR-48)	Schedule C-11	Allowance for Funds Used During Construction for the Projected 12-Month Period Ending September 30, 2025;
Exhibit A-13 (HLR-49)	Schedule C-12	Income Tax Effect of Interest for the Projected 12-Month Period Ending September 30, 2025; and
Exhibit A-13 (HLR-50)	Schedule C-13	Interest Synchronization Adjustment for the Projected 12-Month Period Ending September 30, 2025.

Q. Please discuss the organization and format of the projected test year exhibits.

A. The projected test year exhibits are organized and formatted in a similar fashion to the historical year exhibits. The exhibits are organized into schedules that present the development of the revenue deficiency (Schedule A), rate base (Schedule B), and adjusted NOI (Schedule C). Company witness Marc R. Bleckman is sponsoring schedules that address rate of return (Schedule D). Company witness Keaton is sponsoring sales, load, and customer data (Schedules E) exhibits. Company witnesses Yong F. Keyes, S. Austin Smith, and Kirkland D. Harrington are sponsoring cost-of-service allocation, present and proposed revenue, and proposed tariff sheets (Schedule F) exhibits, respectively.

Q. Please summarize the key findings for the projected test year exhibits.

A. As presented on Exhibit A-11 (HLR-28), Schedule A-1, the key findings from the exhibits for the projected 12-month period ending September 30, 2025 are as follows:

		($ In Thousands)
Rate Base	$	10,970,344
Adjusted NOI	$	578,341
Overall Rate of Return		5.27%
Required Rate of Return		6.20%
Income Required	$	680,004
Income Deficiency	$	101,663
Revenue Conversion Factor		1.3381
Revenue Deficiency	$	136,034

Q. What inflation factors is the Company using in its presentation?

A. The Company is using an inflation factor of 4.2% for 2023, 2.7% for 2024, and an inflation factor of 2.4% for 2025, as forecast by S&P Global and reported in the June 2023 edition of their publication *U.S. Economic Outlook.* S&P Global is a leader in the market of financial information and analytics. Exhibit A-13 (HLR-42), Schedule C-5.1, provides a summary of the inflation impacts included in this instant case.

Q. How has the Company addressed the filing requirement to reconcile the projected test year to the most recent calendar year?

A. The following exhibits reconcile the projected test year to the historical year:

i. Exhibit A-11 (HLR-30), Schedule A-3;

ii. Exhibit A-12 (HLR-34), Schedule B-4;

iii. Exhibit A-13 (HLR-37), Schedule C-1.1;

iv. Exhibit A-13 (HLR-41), Schedule C-5; and

v. Exhibit A-13 (HLR-42), Schedule C-5.1.

Q. Please explain Exhibit A-11 (HLR-29), Schedule A-2.

A. This exhibit presents the financial metrics for the projected test year as required by the Filing Requirements. Column (b) shows metrics assuming no rate relief is granted. Column (c) shows metrics assuming the full rate relief request is granted.

Q. Please explain Exhibit A-11 (HLR-30), Schedule A-3.

A. This exhibit presents the projected test year revenue deficiency for Consumers Energy of $136.0 million (line 13, column (f)). Column (d) of the exhibit presents rate base and rate of return amounts for the historical year. Column (e) shows the changes resulting from adjustments as supported by the various Company witnesses that were made in developing the projected test year revenue requirement. Column (f) shows the rate base, income requirement, and revenue requirement for the 12-month period ending September 30, 2025.

Q. What are the major differences between the historical year and the projected test year results shown on Exhibit A-11 (HLR-30), Schedule A-3?

A. The comparison of historical and projected results in Exhibit A-11 (HLR-30), Schedule A-3, shows that rate base increases by approximately $2.3 billion (line 7) and the rate of return increases from 5.72% to 6.20% (line 8). In addition, adjusted NOI (line 10) increases by approximately $80.8 million from the historical year to the projected test year.

Q. Please describe Exhibit A-12 (HLR-31), Schedule B-1.

A. Exhibit A-12 (HLR-31), Schedule B-1, is a summary presentation of the projected test year average rate base. The average rate base for the 12 months ending September 30, 2025 is $11.0 billion as disclosed on line 8.

Q. Please describe Exhibit A-12 (HLR-32), Schedule B-2.

A. Exhibit A-12 (HLR-32), Schedule B-2, shows the total utility plant for the projected test year. The total on line 26 is carried forward to line 1 on Exhibit A-12 (HLR-31), Schedule B-1.

Q. Please describe how the projected test year average utility plant and related amounts were developed.

A. Average utility plant and reserve balances for the projected test year were developed by taking the average of the balances at September 30, 2024 and September 30, 2025. Actual calendar year 2022 balances for construction work-in-progress ("CWIP"), gross plant, and accumulated provision for depreciation were used as the starting point. Projected capital expenditures (including Allowance for Funds Used During Construction ("AFUDC")) and plant additions were added for the calendar year 2023, calendar year 2024, and for the nine months ending September 30, 2025; followed by adjustments for projected retirements, depreciation expense, cost of removal, the calculation of the ending balances for CWIP, plant, and the accumulated provision for depreciation.

Q. Please describe Exhibit A-12 (HLR-33), Schedule B-3.

A. Exhibit A-12 (HLR-33), Schedule B-3, presents the depreciation reserve for the projected test year by functional group. The total on line 19 is carried forward to line 2 on Exhibit A-12 (HLR-31), Schedule B-1. The increase in projected depreciation reserve incorporates projected depreciation expense from Exhibit A-13 (HLR-43), Schedule C-6, which I describe later in my testimony.

Q. Please explain Exhibit A-12 (HLR-34), Schedule B-4.

A. Exhibit A-12 (HLR-34), Schedule B-4, develops the Company's proposed projected test year working capital. The starting point for this exhibit is the 2022 historical working capital (column (b)), which is first adjusted to reflect the 13-month average June 2023 ending balances shown in column (d), the most current study practical for inclusion at the time of assembling the case. The June 2023 average balances are then adjusted to reflect changes to: (i) gas stored underground as sponsored by Company witness Timothy K. Joyce (column (e)); (ii) pension and other post-employment benefits ("OPEB") balances based on projections sponsored by Company witness Kendra K. Grob (column (f) and (g)); (iii) prepaid cloud computing balances sponsored by Company witness Stacy H. Baker (column (h)); (iv) accrued tax balances (column (i)); (v) deferred debits for a Standardization Engineering Analysis adjustment sponsored by Company witness Michael P. Griffin (column (j)); and (vi) cash based on projections sponsored by Company witness Bleckman (column (k)).

Q. Why did the Company use the Balance Sheet Method in determining working capital?

A. Use of the Balance Sheet Method was mandated by the MPSC in Case No. U-7350. The Filing Requirements also require that this method be used to develop the allowance for working capital.

Q. Please describe Exhibit A-12 (HLR-35), Schedule B-5.

A. Exhibit A-12 (HLR-35), Schedule-B-5, provides a summary of capital spending as supported by Company witnesses Baker, Bradley S. Bammert, Adam S. Carveth, Matthew J. Foster, Griffin, Quentin A. Guinn, Joyce, Steven Q. McLean, Kristine A. Pascarello, and Lincoln D. Warriner. This exhibit provides capital spending for the bridge years and the projected test year as well as the approved and projected test year capital spending in Case No. U-21308.

Q. Please describe Exhibit A-13 (HLR-36), Schedule C-1.

A. Exhibit A-13 (HLR-36), Schedule C-1, presents the calculation of adjusted NOI for the projected test year of $578.3 million as shown on line 21. Total operating revenues (line 4) are netted against total operating expenses (line 15) to arrive at net operating income on line 16. Further adjustments are made on lines 17, 19, and 20, which utilize normal ratemaking practices to arrive at adjusted NOI on line 21.

Q. Please explain Exhibit A-13 (HLR-37), Schedule C-1.1.

A. Exhibit A-13 (HLR-37), Schedule C-1.1, presents the reconciliation of historical year NOI to projected test year NOI. The exhibit presents revenues in columns (c) through (e), expenses in columns (f) through (p), NOI in column (q), AFUDC in column (r), and adjusted NOI in column (s). The exhibit begins with the historical year on line 1, normalizing adjustments to the historical year on lines 2 through 18, and projected test year adjustments on lines 20 through 33. Total adjusted NOI for the projected test year is shown on line 34, column (s). In general, the revenue and expense adjustments are shown with their accompanying tax impacts to arrive at the adjusted NOI. The historic year NOI of $506.6 million on line 1, column (s), ties to the historic NOI on line 18 of Exhibit A-3 (HLR-9), Schedule C-1.

Q. Please explain the adjustments on Exhibit A-13 (HLR-37), Schedule C-1.1.

A. The adjustments on lines 2 through 18 are made to comply with prior Commission orders and follow traditional ratemaking adjustments to historical results such as: (i) removing regulatory disallowances; (ii) normalizing for unusual, one-time, or out-of-period items;

(iii) bringing certain revenues and expenses "above the line"; (iv) adjusting historical revenues to reflect "normal" weather; and (v) adjusting income taxes. Additional adjustments include certain O&M expense normalizations to better align the historic year with expected expense amounts in the projected test year. These adjustments are supported by my exhibits, supporting workpapers, and the exhibits of other Company witnesses.

The historical year adjusted NOI on Exhibit A-13 (HLR-37), Schedule C-1.1, line 19, column (s), of $497.6 million ties to the adjusted NOI on Exhibit A-3 (HLR-9), Schedule C-1, line 37.

Q. How were the projected test year adjustments on Exhibit A-13 (HLR-37), Schedule C-1.1, developed?

A. These adjustments represent the movement from the historical year adjusted NOI to the projected test year adjusted NOI. The adjustments on lines 20 through 33 are developed from my exhibits and supporting workpapers and from the exhibits of Company witnesses Baker, Bammert, Amy M. Conrad, Foster, Griffin, Grob, Guinn, Joyce, Keaton, McLean, Pascarello, James P. Pnacek, and Brian J. Vanblarcum. The projected test year adjusted NOI on line 34 is the result of netting the projected test year adjustments on lines 20 through 33 against the historical year adjusted NOI on line 19. The projected test year adjusted NOI of $578.3 million on line 34, column (s), ties to the projected test year adjusted NOI on Exhibit A-13 (HLR-36), Schedule C-1, line 21.

Q. Please explain the projected test year adjustments on Exhibit A-13 (HLR-37), Schedule C-1.1.

A. Lines 20, 21, and 23 represent the changes in gross margin from the adjusted historical year to the projected test year and are supported by Company witness Keaton.

Line 22 represents the change in other revenues from the adjusted historical year to the projected test year and are supported by my workpapers.

Lines 24 and 25 represent the change in lost and unaccounted for ("LAUF") and company use gas, respectively, and are supported by Company witness Joyce.

Line 26 represents the change in other O&M expenses from the adjusted historical year to the projected test year and are supported by Company witnesses Baker, Bammert, Conrad, Foster, Griffin, Grob, Guinn, Joyce, McLean, Pascarello, and Pnacek. The adjustments on lines 24 through 26 are expanded on Exhibit A-13 (HLR-41), Schedule C-5.

Line 27 represents the change in the book depreciation expense from the adjusted historical year to the projected test year. As stated above, the Company used the approved book depreciation rates, projected capital expenditures, and assumed plant retirements to determine the depreciation expense adjustment necessary to arrive at an appropriate level of book depreciation expense.

Line 28 represents an adjustment to real and personal property tax to the projected test year amount supported by Company witness VanBlarcum and shown on Exhibit A-13 (HLR-44), Schedule C-7, line 1.

Line 29 represents the change in historical year payroll and other general taxes to the projected test year amount as shown on Exhibit A-13 (HLR-44), Schedule C-7, lines 6 and 15.

Line 30 represents the impact of City Income Tax ("CIT"). The projected test year CIT expense is shown on Exhibit A-13 (HLR-47), Schedule C-10.

Line 31 reflects the impact of Michigan Corporate Income Tax ("MCIT"). The projected test year MCIT expense is shown on Exhibit A-13 (HLR-46), Schedule C-9.

Line 32 represents the Federal Income Tax ("FIT") adjustments which result from the other changes in revenues and expenses in the projected test year. Line 32 also reflects the differences between the FIT expense calculated at the current federal statutory rate and the actual total income tax expense. The projected test year FIT expense is shown on Exhibit A-13 (HLR-45), Schedule C-8.

Line 33 represents an adjustment to AFUDC from the adjusted historical year to the projected test year. The projected test year AFUDC is shown on Exhibit A-13 (HLR-48), Schedule C-11. AFUDC is an accounting convention that recognizes the costs, both interest and equity, of financing certain construction projects. The recognition is through the transfer of interest and equity cost from the income statement to CWIP on the balance sheet. The interest and equity costs are capitalized in the same manner as construction labor and material costs when the project is closed to plant-in-service. The criteria for applying AFUDC to a construction project require on-site construction activities of more than six months duration and an estimated plant cost (excluding AFUDC) in excess of $50,000. This adjustment decreases AFUDC because AFUDC is expected to be less in the projected test year than in the historical year.

Q. Please describe Exhibit A-13 (HLR-38), Schedule C-2.

A. Exhibit A-13 (HLR-38), Schedule C-2, shows the development of the revenue conversion factor for the projected test year. The revenue conversion factor converts a utility's after-tax income deficiency (or sufficiency) into the required pre-tax revenue requirement.

For the projected test year, the FIT rate is 21.00%, the MCIT rate is 5.24%, and the CIT rate is 0.16%, which results in a revenue conversion factor of 1.3381.

Q. Please explain Exhibit A-13 (HLR-39), Schedule C-3.

A. Exhibit A-13 (HLR-39), Schedule C-3, presents the total operating revenues for the projected test year. Lines 1 and 2 of the exhibit present the sales and transportation revenue supported by Company witness Keaton. Line 3 presents the other revenues supported by my workpapers. The total on line 4 is carried forward to the Company's projected adjusted NOI presentation on Exhibit A-13 (HLR-36), Schedule C-1.

Q. Have changes been made to the calculation of total operating revenues in Exhibit A-13 (HLR-39), Schedule C-3?

A. Yes. Transportation penalty revenues have been removed from the calculation of other revenues for the projected test year. The Company has determined that these revenues should benefit Gas Cost Recovery ("GCR") customers and reduce its GCR cost of gas. Beginning on October 1, 2024, the Company will reflect actual (i.e. collected) transportation penalty revenues as a reduction to the GCR cost of gas in the Company's 2024 – 2025 GCR reconciliation proceeding pursuant to Public Act 304 of 1982, instead of treating those revenues as an offset to the Company's revenue requirement for purposes of calculating the Company's base gas rates.

In addition, pursuant to the Order in Case No. U-21458, the Company has committed to exclude certain customer billing deductions from its calculation of other revenues for the 2022 historical year. This, in turn, will increase projected test year revenues by $10,853.

Q. Please explain Exhibit A-13 (HLR-40), Schedule C-4.

A. Exhibit A-13 (HLR-40), Schedule C-4, presents the cost of gas sold for the projected test year. The projected test year cost of gas sold is supported by Company witness Keaton. This total is carried forward to line 5 of the Company's projected adjusted NOI presentation on Exhibit A-13 (HLR-36), Schedule C-1.

Q. Please explain Exhibit A-13 (HLR-41), Schedule C-5.

A. Exhibit A-13 (HLR-41), Schedule C-5, presents the other O&M expenses for the projected test year as compared to the historical year. The amounts on lines 1 through 24 were provided by Company witnesses Baker, Bammert, Conrad, Foster, Griffin, Grob, Guinn, Joyce, McLean, Pascarello, and Pnacek and are supported in their direct testimony and exhibits. Lines 25 through 27 are supported by my workpapers. LAUF gas (line 7), company use gas (line 8), and total O&M expense (line 31) are carried forward to lines 6, 7, and 8, respectively, of the Company's projected adjusted NOI presentation on Exhibit A-13 (HLR-36), Schedule C-1.

Q. Please explain Exhibit A-13 (HLR-42), Schedule C-5.1.

A. Exhibit A-13 (HLR-42), Schedule C-5.1, provides a summary of inflation and merit increases included in other O&M expense. Amounts projected using a method other than inflation and merit are included in column (g). The amounts on lines 1 through 24 were provided by Company witnesses Baker, Bammert, Conrad, Foster, Griffin, Grob, Guinn, Joyce, McLean, Pascarello, and Pnacek and are supported in their direct testimony and exhibits. Lines 25 through 27 are supported by my workpapers.

Q. Please explain Exhibit A-13 (HLR-43), Schedule C-6.

A. Exhibit A-13 (HLR-43), Schedule C-6, presents depreciation and amortization expenses by functional grouping for the projected test year. The total on line 21 is carried forward to line 9 of the Company's projected adjusted NOI presentation on Exhibit A-13 (HLR-37), Schedule C-1. The calculated depreciation expense and associated accumulated provision for depreciation presented uses the book depreciation rates approved by the Commission as follows:

1. the Order in Case No. U-18127 dated March 28, 2017 for gas utility plant balances through September 30, 2023;
2. the Settlement Agreement in Case No. U-21176 dated September 8, 2022 for gas utility plant balances from October 1, 2023 through September 30, 2025; and
3. the Order in Case No. U-20849 dated December 9, 2021 for common utility plant.

Book depreciation expense was developed by applying the functional composite book depreciation rates to the average projected test year depreciable plant balances.

Q. Does the Company have a depreciation rate case pending before the Commission that could impact depreciation expense and therefore, the revenue deficiency in this proceeding?

A. No.

Q. Please explain Exhibit A-13 (HLR-44), Schedule C-7, through Exhibit A-13 (HLR-48), Schedule C-11.

A. These exhibits present the following: (i) projected general taxes; (ii) projected FITs; (iii) projected state income taxes; (iv) projected other (or local) taxes; and (v) projected AFUDC. The total from each schedule is carried forward to the Company's projected adjusted NOI presentation on Exhibit A-13 (HLR-36), Schedule C-1.

Q. Please describe Exhibit A-13 (HLR-49), Schedule C-12.

A. Exhibit A-13 (HLR-49), Schedule C-12, shows the calculation of pro forma interest expense for the projected test year and the corresponding impact on income taxes.

Q. Please describe Exhibit A-13 (HLR-50), Schedule C-13.

A. Exhibit A-13 (HLR-50), Schedule C-13, shows the calculation of the tax effect of the interest synchronization adjustment for the projected test year and the corresponding impact on income taxes.

Q. Why are Exhibit A-13 (HLR-49), Schedule C-12, and Exhibit A-13 (HLR-50), Schedule C-13, included in the presentation?

A. The purpose of these exhibits is to align the interest expense and the associated tax benefits in the projected test year with the amount of rate base that is financed with debt and display the alignment in a transparent manner.

III. ACCOUNTING TREATMENT FOR MAOP RETESTING COSTS TO COMPLY WITH NEW FEDERAL SAFETY STANDARDS

Q. Should the Commission allow the Company to adopt the accounting for MAOP retesting costs as approved by FERC in Docket No. AI20-3-000?

A. Yes. In June 2020, the Pipeline and Hazardous Materials Safety Administration ("PHMSA") issued its final rule that addressed, among other items, the safety of gas transmission pipelines, including actions an operator must take to reconfirm the MAOP of natural gas pipelines not yet tested using the new federal safety regulations.[1]

As a result, FERC provided accounting guidance[2] stating that if a utility is required to retest the pipeline so that its full capacity can be utilized, such first-time and one-time

---

[1] *Safety of Gas Transmission Pipelines: Maximum Allowable Operating Pressure Reconfirmation, Expansion of Assessment Requirements, and Other Related Amendments*, 84 Fed. Reg. 51480 (October 1, 2019)

[2] June 23, 2020 FERC Docket No. AI-20-3-000, effective July 1, 2020.

retesting costs can be capitalized. When such retesting costs are capitalized, all prior testing costs related to the specific property should be retired. Based on this guidance, the Company is requesting approval to capitalize first-time and one-time retesting costs incurred due to the new FERC standard. Any related prior capitalized testing would be retired. Please see Company witness Griffin's testimony for further discussion related to the PHMSA transmission safety rules.

Q. Does this complete your direct testimony?

A. Yes.

S T A T E   O F   M I C H I G A N

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the application of **CONSUMERS ENERGY COMPANY** for authority to increase its rates for the distribution of natural gas and for other relief.	)))))	Case No. U-21490

REDACTED

DIRECT TESTIMONY

OF

S. AUSTIN SMITH

ON BEHALF OF

CONSUMERS ENERGY COMPANY

December 2023

Q. Please state your name and business address.

A. My name is S. Austin Smith, and my business address is One Energy Plaza, Jackson, Michigan 49201.

Q. By whom are you employed?

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

Q. What is your position with Consumers Energy?

A. I am a Rate Analyst in the Cost and Pricing Section of the Rates and Regulation Department.

Q. Please state your educational background and work experience.

A. I received a Bachelor of Business Administration degree with an emphasis in Accounting in April 2014 from Alma College. In Spring 2019, I earned a Master of Business Administration degree from Spring Arbor University. In August 2016, I began employment as a Rates Analyst in the Pricing Section of the Legal, Rates & Regulatory Department at Consumers Energy. My responsibilities included preparing various electric and gas rate analyses, supporting witnesses in general electric and gas rate case filings, sponsoring the recovery of Energy Waste Reduction ("EWR") costs and financial incentives in EWR Plan and Reconciliation case filings, sponsoring the reconciliation of gas Revenue Decoupling Mechanisms ("RDM") in Gas RDM case filings, and validating electric and gas charges as part of the Company's billing process.

Q. Have you previously filed testimony with the Michigan Public Service Commission ("MPSC" or the "Commission")?

A. Yes. I have filed testimony in the following cases:

Case No. U-17771 (Amended) Energy Optimization Plan, Rate Design;

Case No. U-18261	EWR Plan, Rate Design;
Case No. U-18331	EWR Reconciliation, Rate Design;
Case No. U-20028	EWR Reconciliation, Rate Design;
Case No. U-20275	Electric Self-Implementation Reconciliation, Rate Design;
Case No. U-20356	Gas Revenue Decoupling Reconciliation, Rate Design;
Case No. U-20671	Gas Revenue Decoupling Reconciliation, Rate Design;
Case No. U-21205	EWR Reconciliation;
Case No. U-21233	Demand Response Reconciliation;
Case No. U-21344	Gas Revenue Decoupling Reconciliation, Rate Design; and
Case No. U-21410	Demand Response Reconciliation.

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

A. The purpose of my direct testimony is to present the Company's proposed rate design, which collects the proposed revenue requirement from customers in an equitable manner reflecting the cost of providing service and taking into consideration rate impacts.

Q. Are you sponsoring any exhibits?

A. Yes, I am sponsoring the following exhibits:

Exhibit A-16 (SAS-1)	Schedule F-2	Summary of Present and Proposed Revenue by Rate Schedule;
Exhibit A-16 (SAS-2)	Schedule F-2.1	Summary of Present and Proposed Rates by Rate Schedule;
Exhibit A-16 (SAS-3)	Schedule F-2.2	Calculation of Rate Design Targets;
Exhibit A-16 (SAS-4)	Schedule F-3	Present and Proposed Revenue Detail;
Exhibit A-16 (SAS-5)	Schedule F-3.1	Transmission Only Transportation Service Rate;

Exhibit A-16 (SAS-6)	Schedule F-4	Comparison of Present and Proposed Monthly Bills;
Exhibit A-107 (SAS-7)		Development of Rates for Transportation ATL Services;
Exhibit A-108 (SAS-8)		Calculation of Test Year Discount and Carrying Cost Rates for the Customer Attachment Program; and
Confidential Exhibit A-109 (SAS-9)		[redacted]

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

A. Yes.

Q. How is your direct testimony organized?

A. My direct testimony is organized as follows:

I. SUMMARY OF PROPOSED RATE DESIGN CHANGES

II. ALLOCATION OF THE PROPOSED REVENUE DEFICIENCY

III. TRANSMISSION ONLY TARIFF

IV. TYPICAL BILLS

V. CUSTOMER ATTACHMENT PROGRAM DISCOUNT AND CARRYING COST

VI. [redacted]

I. SUMMARY OF PROPOSED RATE DESIGN CHANGES

Q. Please describe Exhibit A-16 (SAS-1), Schedule F-2.

A. Exhibit A-16 (SAS-1), Schedule F-2, provides a summary of the proposed changes in revenue by rate schedule. The proposed change is derived from the calculated difference between test year present revenue and proposed revenue that incorporate the Company's revenue deficiency. The present and proposed revenues shown in Exhibit A-16 (SAS-1), Schedule F-2, are calculated by applying the test year billing determinants provided by Company witness Eric J. Keaton to present rates, as well as to the rates being proposed by the Company in this case.

Q. What rates were used to calculate present revenue?

A. The Company applied the rates approved by the Commission in the MPSC Case No. U-21308 August 30, 2023 Order Approving Settlement Agreement ("August 30 Order") to the test year billing determinants to calculate present revenue in Exhibit A-16 (SAS-1), Schedule F-2.

Q. Please describe the Company's objectives and approach to rate design in this case.

A. Generally, the Company has designed rates so that the revenue recovered from each customer class reflects the adjusted costs for that class in the Company's test year Cost of Service Study ("COSS"). The Company also considers: (i) establishing rates that promote efficient use of the Company's gas system and promoting energy efficiency; (ii) establishing rates that promote a favorable business climate; and (iii) designing rates that provide the Company with a fair opportunity to collect its revenue requirements. The proposed gas delivery revenue and associated rate increases/(decreases) for each rate class are shown on Exhibit A-16 (SAS-1), Schedule F-2, page 2.

<u>Residential Rates</u>

The Company is proposing to maintain its existing residential rate structure for Rate Schedules A and A-1, which includes a fixed monthly customer charge and volumetric distribution charges. The proposed increase in distribution for Rates A and A-1 is 9.2% and 2.1% respectively, as shown on Exhibit A-16 (SAS-1), Schedule F-2, page 2. The total proposed increase for the residential class is 5.7% when including the forecasted cost of the gas commodity, as shown on Exhibit A-16 (SAS-1), Schedule F-2, page 1.

General Service Rates

The Company is proposing to maintain its existing rate structure for General Service Rate Schedules GS-1, GS-2, and GS-3. The proposed increase in distribution for the General Service rate class is 14.7%, as shown on Exhibit A-16 (SAS-1), Schedule F-2, page 2. The total proposed increase for the General Service class is 8.1% when including the forecasted cost of the gas commodity, as shown on Exhibit A-16 (SAS-1), Schedule F-2, page 1. The proposed rates maintain the currently established economic breakeven points between the General Service Rate Schedules, GS-1, GS-2, and GS-3.

Transportation Rates

The Company is proposing to maintain its existing transportation rate structure with Rate Schedules ST, LT, XLT, and XXLT. The proposed decrease for the Transportation rate class is 5.5%, as shown on Exhibit A-16 (SAS-1), Schedule F-2, page 1. The proposed rates maintain the currently established economic breakeven points between the Transportation Rate Schedules ST, LT, and XLT. The Company is also proposing to add a Transmission Only Transportation Service Rate.

General Lighting Rate GL

Rate GL is a rate dedicated to customers with gas lighting and is closed to new business. Currently, only a few customers are served on this rate. The Company proposes a 12.2% decrease for Rate GL using the Company’s projected cost of gas of $3.864 per Mcf, which is supported by Company witness Timothy K. Joyce in his direct testimony.

The cost of gas is included with other distribution costs in the fixed monthly rate for single and multiple gas fixtures.

II. ALLOCATION OF THE PROPOSED REVENUE DEFICIENCY

Q. Please describe Exhibit A-16 (SAS-3), Schedule F-2.2.

A. Exhibit A-16 (SAS-3), Schedule F-2.2, shows the calculation of the revenue targets used for designing rates, including proposed adjustments, to the test year revenue requirement by rate schedule. The exhibit illustrates test year revenues based on the Company's test year COSS (Version 2), as shown in Exhibit A-16 (YFK-2), Schedule F-1.1. This is followed by the Company's proposed adjustments to the COSS, which results in the revenue target used for designing the Company's proposed rates.

Q. How did the Company develop the test year revenue targets for each class shown on Exhibit A-16 (SAS-3), Schedule F-2.2?

A. As shown on Exhibit A-16 (SAS-3), Schedule F-2.2, page 1, line 1, the Company started with the test year COSS. The COSS was adjusted for the Residential Income Assistance ("RIA") provision and the Low-Income Assistance Credit ("LIAC") to assign cost responsibility for these assistance programs to all rate schedules, as shown on Exhibit A-16 (SAS-3), Schedule F-2.2, page 1, line 2. Furthermore, the COSS was adjusted to reflect the storage adjustment for Rate XXLT, as shown on Exhibit A-16 (SAS-3), Schedule F-2.2, page 1, line 3. Consistent with the methodology approved by the Commission in prior gas cases, the COSS was also adjusted to maintain economic breakeven points within the General Service and Transportation rate classes. In the interest of rate stability and to moderate rate impacts for customers on Rate GS-1, the Company is proposing to shift proposed revenue. Approximately $9.2 million has been shifted into Rates GS-2 and GS-3 from Rate GS-1. The adjusted cost of service was compared to the test year present revenue to determine the revenue deficiency by class. This deficiency was then adjusted for incremental late payments to determine the adjusted deficiency. The adjusted deficiency was added to the test year present revenue, resulting in the rate design targets by rate schedule as shown on Exhibit A-16 (SAS-3), Schedule F-2.2, page 1, line 11.

Q. How did the Company allocate the low-income credits associated with the RIA credit and LIAC?

A. The allocation of the RIA credit and LIAC is shown on Exhibit A-16 (SAS-3), Schedule F-2.2, page 2. The credits are allocated to each rate class based on that class's pro rata share of the total revenue requirement from the COSS.

Q. What is the basis for allocating the RIA credit and LIAC among all rate schedules?

A. The Company is maintaining the allocation ordered by the Commission in its June 3, 2010 Order in Case No. U-15985 (Michigan Consolidated Gas Company's gas general rate case) ("U-15985 Order"). The Order states:

> The ALJ found that the revenue shortfall should be recovered from all rate classes, on the basis of Allocation Factor No. 20 rather than on the basis of throughput. [U-15985 Order, page 91.]
>
> The Commission adopts the findings and recommendations of the ALJ. For the electric utilities, this shortfall is spread to all customer classes and the Commission is not persuaded that gas should be treated differently. See, MCL 460.11 (3). The Commission further finds that spreading it on the basis of cost of service plus the cost of gas is fair and reasonable. [U-15985 Order, page 92.]

Q. Please describe Exhibit A-16 (SAS-4), Schedule F-3.

A. Exhibit A-16 (SAS-4), Schedule F-3, calculates the test year proposed gas rates required to collect the revenue requirement derived from the test year calculation of rate design targets shown in Exhibit A-16 (SAS-3), Schedule F-2.2, page 1, line 11 for each rate schedule, based on the billing determinants provided by Company witness Keaton. Both the present and proposed gas prices are applied to the billing determinants to calculate the test year revenue on Exhibit A-16 (SAS-1), Schedule F-2. The rates from this exhibit are the source of the proposed rates that appear in the redlined tariffs filed by Company witness Kirkland D. Harrington in this case.

Q. How does the Company propose to design rates to recover the residential revenue requirement?

A. The Company calculated a residential customer charge using the methodology originally adopted by the Commission in MPSC Case No. U-4331, January 18, 1974 Order, page 30. This methodology limits the customer charge to only those costs associated directly with supplying service to a customer, such as costs associated with metering, the service lateral, and customer billing. Using this methodology, the Company calculated a residential customer charge of $19.86 per month.

Although the Case No. U-4331 methodology supports an increase of more than $6.00 to the Company's current residential customer charge, the Company proposes a residential customer charge for Rates A and A-1 of $18.60 per month. This proposal reflects a $5.00 increase from the current $13.60 residential customer charge. Using this approach, the Company can move the residential customer charge closer to the cost to serve while at the same time allow for a more gradual increase in the fixed charge. The increase in the customer charge also results in a corresponding increase to the low-income RIA monthly credit. The more revenue collected via the fixed customer charge, the greater the proportion of the RIA customer's bill is offset by the fixed monthly credit.

Q. Does the proposed increase in the residential customer charge result in a change to the volumetric distribution charge?

A. Yes. The proposed $5.00 increase in the customer charge results in a volumetric distribution charge of $5.2165. If the customer charge remained at $13.60, the distribution charge would be $5.8442.

Q. Will the increased residential customer charge increase bills for below-average users?

A. The average monthly consumption for a residential customer is 8.1 Mcf per month. With an $18.60 customer charge and $5.2165 distribution charge, a customer with below-average usage of 4.5 Mcf (for example) would only spend $26 more annually than if they had a $13.60 customer charge and $5.8442 distribution charge.

Q. Will the increased customer charge adversely affect customers who qualify for income assistance provisions?

A. No. In fact, customers qualifying for the RIA provision will see the benefit of lower bills, since the customer charge is completely offset by the RIA credit.

Q. How does Consumers Energy's customer charge compare to that of peer utility companies in the Midwest region?

A. Several large investor-owned utilities in the Midwest have monthly fixed charges above $20 and even above $30, some for more than a decade. These include Columbia Gas (OH), CenterPoint Energy (OH), Duke Energy (OH), Peoples Gas (IL), and Nicor Gas (IL).

Q. What are the benefits of increasing the residential customer charge?

A. A higher customer charge results in greater bill stability by reducing monthly volatility in customers' bills. This can be especially beneficial through the winter heating months, when customers use more gas. The volumetric element of the bill is reduced, which reduces the impacts of above-average consumption due to colder than normal temperatures. Higher fixed charges also reduce the necessity and impact of revenue decoupling mechanisms.

Q. Is the Company recommending a rate change to the Excess Peak Demand Charge for residential Rate A-1 customers?

A. Yes. The Excess Peak Demand Charge collects the higher metering costs associated with Rate A-1 customers; therefore, the Company proposes to increase this charge by the same percent increase as the residential customer charge. The proposed Excess Peak Demand Charge is shown on Exhibit A-16 (SAS-4), Schedule F-3, page 2, line 2, column (f).

Q. How does the Company propose to set rates to recover the revenue requirement for the General Service Rate Schedules GS-1, GS-2, and GS-3?

A. Consistent with the August 30 Order, the Company is proposing principal customer charges, contiguous customer charges, and volumetric distribution charges to collect the proposed revenues. These rate changes maintain the economic breakeven points between Rate Schedules GS-1 and GS-2 at 1,000 Mcf annually and between Rate GS-2 and Rate GS-3 at 10,000 Mcf annually, as well as provide for the recovery of the annual revenue requirement for the General Service rate class. These rate changes are shown in Exhibit A-16 (SAS-2), Schedule F-2.1.

Q. How does the Company propose to set rates to recover the Transportation class's revenue requirement?

A. Consistent with the August 30 Order, the Company is proposing principal customer charges, contiguous customer charges, and distribution charges to collect the Transportation proposed revenues. The principal customer charges for ST and XXLT are set based on the COSS. The principal customer charges for LT and XLT are set to maintain the economic breakeven points. The Company proposes to maintain the contiguous customer charge at $60 for all ST, LT, and XLT contiguous accounts. These rate changes maintain the economic breakeven point between Rate ST and Rate LT at 100,000 Mcf annually and the breakeven point between Rate LT and Rate XLT at 500,000 Mcf annually, as well as provide for recovery of the annual revenue requirement for the Transportation class. Furthermore, as approved in the August 30 Order, the Company is maintaining Rate XXLT's minimum annual eligibility requirement of 4 Bcf. These rate changes are shown in Exhibit A-16 (SAS-2), Schedule F-2.1.

Q. Please explain economic breakeven points.

A. An economic breakeven point is the point of volumetric usage where revenue collected from one rate would equal revenue collected on a different rate.

Q. Is the Company proposing to reset the economic breakeven points?

A. No. The Company's proposed rates in this case maintain the breakeven points established in Case No. U-18124, and subsequently approved in Case No. U-18424, Case No. U-20322, Case No. U-20650, Case No. U-21148, and Case No. U-21308.

Q. Why does the Company strive to maintain economic breakeven points as part of the rate design?

A. Maintaining breakeven points allows for greater precision in revenue prediction and, therefore, greater accuracy in setting rates and minimizes confusion for customers. When economic breakeven points change, customers have an economic incentive to switch from their existing rate to a more economical rate. This can result in under- and over-recovery of costs if many customers shift rates. In addition, frequent shifts from rate to rate on a large scale can create volatility in revenues received by the Company. This makes it difficult to accurately predict future revenues for ratemaking and planning purposes. Maintaining economic breakeven points minimizes volatility by eliminating any economic incentive to change rates when the customer use has not changed, while simultaneously establishing cost-based rates for the General Service class. However, it may be necessary in certain circumstances to realign the breakeven points if the individual rate classes continue to move further from their cost-basis and maintaining the current breakeven points are no longer appropriate.

Q. Please explain Authorized Tolerance Levels ("ATL").

A. An ATL is a percentage of a transportation customer's annual contract quantity ("ACQ"). The ATL is the percentage of the ACQ which the transportation customer can have in storage at the end of any given month without incurring additional Load Balance charges. The ACQ is based on the highest 12 consecutive months during the contract's 36-month lookback period. The ACQ is calculated either at the beginning of the contract or during the periodic review, which occurs every five years.

Q. Is the Company proposing changes to the ATLs offered?

A. No. Exhibit A-107 (SAS-7) provides the credit calculation, and Exhibit A-16 (SAS-4), Schedule F-3, provides the revenue calculation for each transportation rate class, consistent with the structure approved in the August 30 Order.

Q. Is the Company proposing changes to the transportation charge adjustment associated with the ATLs?

A. No. Consistent with the August 30 Order, the Company has directly adjusted the per Mcf storage cost based on the ratio of the ATL tiers and the weighted average ATL of 6.5%.

This results in a cost per Mcf for each tier of ATL, including the 8.5% tier. The Company then adjusted each of the tiers by the 8.5% tier to keep the 8.5% tier as the neutral default level. Exhibit A-107 (SAS-7), provides this adjustment calculation.

Q. Is the Company proposing any other changes related to the 4.0% ATL adjustment for Rate XXLT?

A. No. Consistent with the August 30 Order, the Company has spread the 4.0% ATL adjustment given to Rate XXLT back to all other transportation rate schedules by directly adjusting the per Mcf storage cost based on the ratio of the ATL tiers and the weighted average ATL of 6.5%.

Q. In the development of Rate Design, does the Company separate Gas Customer Choice ("GCC") sales from Gas Cost Recovery ("GCR") sales?

A. No. The rate design calculates delivery charges for all customers. GCC and GCR customers pay the same delivery charges, thus there is no need to separate GCC sales from GCR sales. Only total sales are needed as separating them has no impact on rate design.

III. TRANSMISSION ONLY TRANSPORTATION SERVICE RATE

Q. Please describe the proposed Transmission Only Transportation Service Rate proposal.

A. The Company is proposing to create a Transmission Only Transportation Service Rate to provide a transparent rate option for customers looking to take service directly from the transmission system. Today these customers must enter into an Act 9 contract and the transmission rate is only updated when a new contract is signed. Having a transparent tariff rate option allows the rate to be updated to reflect the latest Commission-approved transmission costs.

Q. How was the transmission only rate designed?

A. The Company designed a transmission only rate for small, large, extra-large, and extra extra-large service which follows the transportation rate schedules. The transmission costs from the cost of service, as allocated to the transportation rate schedules, were divided by the corresponding transportation sales forecast to develop a per Mcf transmission cost. This is shown on Exhibit A-16 (SAS-5), Schedule F-3.1, Transmission Only Transportation Service Rate.

Q. How will the revenue from customers on this rate be treated?

A. The revenue from these customers will be included in other revenue and will serve as an offset to the Company's revenue requirement. This is consistent with how Act 9 customer revenue is treated today.

Q. Did the Company project any customer usage and revenue during the test year?

A. The Company does expect that some customers could take this rate during the test year given the termination dates of existing Act 9 contracts. However, the usage for the test year is expected to be minimal and the revenue will not be significantly different from what is included in other revenue for the Act 9 contracts today. Therefore, the Company did not make any adjustments to sales or revenue for this proposal.

IV. <u>TYPICAL BILLS</u>

Q. Please describe Exhibit A-16 (SAS-6), Schedule F-4.

A. Exhibit A-16 (SAS-6), Schedule F-4, provides the impacts resulting from the proposed gas rates and rate design changes for customers on each rate schedule at various usage levels. This exhibit is used to gauge the distribution of the rate impacts across the population of customers taking gas service under the various rate schedules.

V. <u>CUSTOMER ATTACHMENT PROGRAM DISCOUNT AND CARRYING COST</u>

Q. Please explain Exhibit A-108 (SAS-8).

A. Exhibit A-108 (SAS-8) provides the calculation of the test year discount and carrying cost rates for the Customer Attachment Program ("CAP") and is used to support the changes to the CAP tariff sheet sponsored by Company witness Harrington.

VI. [redacted]

[redacted]

Q. Does this complete your direct testimony?

A. Yes.

S T A T E O F M I C H I G A N

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the application of **CONSUMERS ENERGY COMPANY** for authority to increase its rates for distribution of natural gas and for other relief.	)))))	Case No. U-21490

DIRECT TESTIMONY

OF

R. MICHAEL STUART

ON BEHALF OF

CONSUMERS ENERGY COMPANY

December 2023

Q. Please state your name and business address.

A. My name is R. Michael Stuart, and my business address is One Energy Plaza, Jackson, Michigan 49201.

Q. By whom are you employed and what is your present position?

A. I am employed by Consumers Energy Company ("Consumers Energy" or the "Company") as Director of Quality Improvement.

Q. Please review your educational and business experience.

A. I graduated from Michigan State University in December of 1985 with a Bachelor of Arts Degree in Business Administration. Since joining Consumers Energy in June of 2000, I have held various positions in the Supply Chain, Electric Meter Operations, Business Technology Support, Strategy Mobilization and Integration, and Quality Lean Office Departments.

Q. What are your responsibilities as Director of Quality Improvement?

A. In the Director of Quality Improvement role, I am responsible for the development, governance, and administration of the operational metrics incorporated in the Company's Employee Incentive Compensation Plan ("EICP"), and leading a team responsible for establishing, and supporting the Company's lean operating system.

Q. Have you previously filed testimony with the Michigan Public Service Commission ("MPSC" or the "Commission")?

A. Yes, I filed testimony in Case No. U-17643 and testified in Case Nos. U-17735, U-17882, U-17990, U-18124, U-18332, U-20650, U-20697, U-20963, U-21148, U-21224, U-21308, and U-21389.

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

A. The purpose of my direct testimony is to provide support for Consumers Energy's request for rate recovery for the test year EICP employee compensation costs related to operational goals. Specifically, I will discuss the operational goals included in Consumers Energy's EICP and how they provide customer-related benefits.

Q. Are you sponsoring any exhibits?

A. Yes, I am sponsoring the following exhibits:

Exhibit A-110 (RMS-1)	2023 EICP Operational Goals;
Exhibit A-111 (RMS-2)	2023 Customer Benefits: Employee Safety;
Exhibit A-112 (RMS-3)	2023 Customer Benefits: Reliability; and,
Exhibit A-113 (RMS-4)	2023 Customer Benefits: Culture Index.

Q. Please explain the process for establishing the Company's EICP goals.

A. Each year, the Company identifies key operational and financial performance indicators to focus on for the next year. The EICP operational goals are key performance indicators that focus on continuously evaluating work and delivery processes for opportunities to improve and enhance safety, reliability, and customer value.

Q. What operational goals make up the 2023 EICP portfolio?

A. The 2023 EICP operational goal portfolio is balanced to produce safe, reliable, and affordable service while ensuring that the Company is strategically positioned for its customers in the future. Successfully achieving goals in Employee Safety, Culture, Customer Experience, Electric Reliability, and Methane Emission Reduction will produce safe, reliable, affordable service, and help to position the Company to be strong and sustainable in the future. Additional information regarding the 2023 portfolio of EICP goals is provided in Exhibit A-110 (RMS-1).

Q. Please explain the Employee Safety goal?

A. Employee Safety is measured through two metrics. First, reduction of high-risk injuries ensures coworkers take proactive actions to reduce Company employees' exposure to high-risk injuries as part of Consumers Energy's Safety Culture improvement process. High-risk injuries (Occupational Safety and Health Administration ("OSHA") recordable and non-recordable) are defined in the Edison Electric Institute ("EEI") Safety Classification Learning Model as "High-Energy Serious Injury or Fatality (HSIF): Incident with a release of high energy in the absence of a direct control where a serious injury is sustained." Second, reduction of Recordable Incident Rate (per the OSHA standard) is an excellent guide of the number of injuries that occur based upon the number of hours worked.

Q. Why is the Employee Safety goal included in the EICP?

A. Employee Safety is foundational to the success of the Company. Creating and maintaining a culture of safety allows the Company to serve customers safely and affordably while caring for co-workers. Economic benefits for customers are discussed later in my testimony.

Q. Please explain the Culture Index goal?

A. The Company uses an all-employee survey to determine the Culture Index which is made up of the indexes of Engagement; Empowerment; and Diversity, Equity, and Inclusion. The Company's Engagement; Empowerment; and Diversity, Equity, and Inclusion indexes are how we measure culture values in action. The indexes focus on things like ensuring the Company has simple processes, fixes problems, keeps workforce engaged by measuring the combination of emotional commitment (are you proud to work here?) and rational commitment (do you plan to stay?) and embed diversity, equity, and inclusion into everything we do (do you feel like you belong at Consumers Energy?). Each of the three indexes is derived by averaging the favorability score from the responses regarding five questions per index, of the Company's employee engagement surveys administered by Korn Ferry and Qualtrics.

Q. Why is the Culture Index goal included in the EICP?

A. The Culture Index goal focuses on improving the employee experience and their engagement in their work. Companies that experience high employee engagement have 10% higher customer loyalty and engagement and 18% more productivity than companies with low engagement as detailed in Gallup's most recent meta-analysis on engagement, covering more than 112,000 teams, in 276 organizations, across 54 industries and in 96 countries.[1] Improving Culture will reduce employee turnover and improve the Company's ability to affordably service customers. The continuity of our workforce is extremely critical to delivering our Natural Gas Strategy to customers. Delivering on this strategy through the retention of our existing workforce creates continuity in our plans and a stronger assurance of on-time delivery. Currently, we are in the midst of what Human Resources experts are calling "The Great Resignation." Employees are leaving companies at surprising rates, with a record 4.3 million Americans quitting their job in August 2021. The Company has not realized this amount of attrition, largely due to its employee engagement and experience strategy. However, although our retention rate is higher, our voluntary turnover is increasing, particularly in co-workers who have been with the

[1] https://www.gallup.com/workplace/285674/improve-employee-engagement-workplace.aspx#ite-285704

company for four or less years, with that turnover being higher than those that have been with the company for five or more years. Unsurprisingly, retention and engagement are correlated, companies with first quartile employee engagement experience 43% less turnover and 18% lower absenteeism. The cost of turnover is high, with estimates that losing an employee can cost a company 1.5-2.0 times the existing employee's salary as the organization shifts to additional attraction and lost productivity. For purposes of quantifying customer benefits I will utilize the lower end of this range, 1.5 times the existing employee's salary. Approximately 35% (3,127) of our co-worker base has four or less years with the company. Creating and building upon an employee experience that fosters improved retention within that work group enables the Company to provide better service to our customers and avoid unnecessary costs. Through the Company's Culture Index goal, a focus on improving our retention for our shorter tenured company employees by just 2%, to be more consistent with the rest of the Company, will avoid costs of $8.7 million.

Q. Please explain the Customer Experience Index goal?

A. Customer Experience Index is a survey administered by Forrester[2] and is a measure of customer service based on three questions: Did we meet your needs? Was it easy to do business with us? Was the experience enjoyable. The metric is calculated by asking those three questions of customers on a scale of 1 to 5 with 4s and 5s being positive responses, 1s and 2s being negative responses, and 3s being a neutral response. To calculate the score, the number of negative responses is subtracted by the number of positive responses, which

[2] https://go.forrester.com/analytics/

is then divided by the total number of customers responding. The results of the three questions are averaged together to calculate the Customer Experience Index score.

Q. Why is the Customer Experience Index goal included in EICP?

A. The Customer Experience Index goal focuses on ensuring that when customers contact Consumers Energy, customer needs are met, the interaction is easy for the customer, and the experience is enjoyable for the customer. This results in enhanced productivity (e.g., reducing the number and duration of customer calls, which benefits the Company and the customer) and customer value (e.g., quick, easy, and enjoyable solutions for customer experiences).

Q. Please explain the Electric Reliability goal?

A. The Company uses the industry standard for Customer Outage Minutes, or System Average Interruption Duration Index ("SAIDI") as a measure of electric distribution reliability. Electric Reliability/SAIDI is a utility-industry benchmark; SAIDI measures the total time an average customer experiences a non-momentary power interruption in a one-year period.

Q. Why is the Electric Reliability goal included in EICP?

A. The Company is committed to providing Customers with Safe, Reliable, Affordable service. Improving electric reliability provides an economic benefit to customers which is discussed later in my testimony and strategically positions the Company to be successful in the future. Economic benefits for customers are discussed later in my testimony.

Q. Please explain the Methane Emissions Reduction goal?

A. This goal tracks the reduction in fugitive methane emissions associated with the Company's natural gas distribution system. Reductions are obtained as a result of the following activities: 1) Retiring & Replacing Miles of Gas Distribution Mains, 2) Retiring & Replacing Gas Distribution Services (Both Vintage & Non-Vintage Materials), 3) Gas Distribution System Leak Replacements, 4) Well Plug & Abandonment activities, and 5) Reducing Compression Venting. Work groups performing these activities include Gas Construction, Gas Distribution, and Contractors. These activities are further outlined in the Company's Natural Gas Delivery Plan.

Q. Why is the Methane Emission Reduction goal included in the EICP?

A. The Company is committed to providing customers with safe, reliable, affordable service. In 2020, Michigan's Governor signed an executive order creating the Michigan Healthy Climate plan, which outlines goals for Michigan to achieve economy-wide net-zero greenhouse gas emissions and to be carbon neutral by 2050. The executive order aims for a 28% reduction below 2005 levels of greenhouse gas emissions by 2025. This goal supports the federal government's goal of net-zero emissions economy-wide by 2050 as well and the Paris Agreement. In addition to supporting these goals through our Clean Energy Plan, it is important to address greenhouse gas emissions from the natural gas portion of our business as well. The largest constituent of natural gas is methane which is a greenhouse gas 25 times more potent than carbon dioxide, and reducing those emissions is a key component to combating climate change. As a result, the company has set a goal of net-zero methane emissions from its natural gas delivery system by 2030. The Company plans to reduce methane emission from its system by about 80% by accelerating the replacement of aging pipe, rehabilitating or retiring outdated infrastructure, and adopting new technologies and practices. The remaining emissions will be offset by purchases and/or producing renewable natural gas. By achieving our goal, we'll reduce our methane emissions by more than 10,000 metric tons (MT) — that's the equivalent of removing about 55,000 vehicles from the road for a year or preserving more than 300,000 acres of forest. Reducing those emissions will support limiting global emission increases which have been attributed to increased storm activity globally as well as here in Michigan. We are committed to caring for people, protecting the planet, and empowering Michigan's prosperity. The achievement of this goal ensures that the Company will be able to serve our customers safely, reliably, and affordably for many years.

Q. Please explain the goal target setting process.

A. Alignment of goal targets with strategic plans is developed by subject matter experts, and recommendations for annual targets are provided to the Company leadership team. The leadership team evaluates the recommendations and ensures that there is tension between areas where significant improvement is needed and where continuous improvement is required to provide safe, reliable, affordable service while strategically positioning the Company for sustainable operation. Targets are balanced in a way that effective annual performance across the portfolio will result in a 100% operational incentive award. Operational targets are approved annually by the Board of Directors.

Q. Has the Company quantified customer benefits that are tied to its EICP?

A. Yes. Although specific quantification of the benefits is not easy to perform for every metric included in the program, the Company has evaluated direct quantitative benefits of three key metrics of the program, Employee Safety, Electric Reliability, and Culture Index, and has assessed indirect and/or qualitative benefits associated with the other metrics.

Q. Is there a direct tie between the design of the EICP operational goals and desirable benefits for customers?

A. Yes. There is a direct tie between the design of the EICP operational goals and desirable benefits for customers. The operational goals focus on safety, reliability, and customer value, which are all desirable benefits for customers.

Q. Do you believe that benefits to customers from the EICP goals will, at a minimum, be commensurate with the programs' costs?

A. Yes. Company witness Amy M. Conrad and I present evidence in support of including EICP costs at the 100% payout level proving that including these costs will not result in excessive rates and that the costs of the EICP will, at a minimum, be commensurate with the programs' costs. Company witness Conrad discusses various benefits to customers from the design of the Company's EICP. In addition, there are both quantitative and qualitative benefits to the successful achievement of these goals. The design of the EICP clearly leads to lower costs and improved service which benefit our customers.

Q. What are the results of the direct quantitative benefits evaluations?

A. The direct quantitative benefits associated with Employee Safety, Electric Reliability, and Culture Index, have been calculated. For each of these metrics the Company uses a four-year historical average baseline. The first of those metrics is Employee Safety. The Employee Safety goal for 2023 will reduce incidents by 10% from the four-year historical average. The resulting reduction in lost workdays and medical expenses approximates $438,000 of annual direct savings. Expected indirect savings total $328,000, which results in total average annual direct and indirect savings of $766,000 that accrue to the benefit of the customer. Exhibit A-111 (RMS-2) provides the calculation of these savings. The second metric that can be readily translated to quantifiable cost avoidance for our customers is in electric distribution reliability. Using cost per outage minute estimates from Berkeley Labs,[3] the 12.7-minute average annual reduction in outage minutes from the 2019 historical baseline to the 2023 Electric Reliability goal of 170 minutes results in annual economic benefits to our customers in excess of $37.7 million. Exhibit A-112 (RMS-3). Third, are benefits related to Culture Index by reducing employee turnover for Company employees with <1-4 years of tenure by 2% or 63 employees on average per year. The average annual salary of an employee with tenure of <1-4 years' experience is $92,350 this equals avoided costs of $8.7 million to $11.5 million. Exhibit A-113 (RMS-4).

Q. What are the results of other quantitative benefits evaluations?

A. Methane Emission Reduction is an important goal supporting the Company's goal of net-zero methane emissions from its natural gas delivery system by 2030, which also supports the Michigan Governor's goal for Michigan to achieve economy-wide net-zero greenhouse gas emissions and to be carbon neutral by 2050, but direct economic benefits for customers are difficult to calculate.

Q. Why have you included both electric and gas benefits in your quantification?

A. Consumers Energy's utility operations are combined in one organization. Establishing operational goals in the critical areas of safety, reliability, and customer value helps keep employees focused on the importance of safety, reliability, and customer value for both the electric and gas operations. The quantified benefits of Employee Safety and Culture Index show that benefits to gas customers clearly exceed the gas incentive compensation amounts

[3] https://www.osti.gov/servlets/purl/963320

that Consumers Energy has requested to be included in rates in this case. The EICP metrics are based on annual targets that support the achievement of Consumers Energy's continuous improvement goals that significantly benefit the customers.

Q. What portion of the direct benefits that you have quantified above do you conclude benefit gas customers?

A. A portion of the quantified benefits in the area of Employee Safety, and avoided costs associated with Culture Index benefit gas customers. Utilizing an allocation of 36% for gas customers, this equates to annual savings for gas customers of $276,000 for Employee Safety, plus the cost avoidance benefit of improved employee retention of $4.7 million totals $6.1 million, far exceeding the total costs of the EICP allocated to gas customers. The total of these two direct benefits to customers is $3.1 million to $4.2 million.

Q. Why did you use a 36% allocation to evaluate benefits to gas customers?

A. The 36% allocation is based on the total number of gas employees as a percentage of total number of Consumers Energy employees. Using the percentage of total employees is a reasonable allocation methodology to use to allocate the Employee Safety, and Culture Index benefits identified above.

Q. Should the Company be pursuing these benefits independent of the EICP?

A. Yes. The EICP takes this into consideration. As discussed by Ms. Conrad in her direct testimony, incentive mechanisms help communicate priorities, engage employees in business success, reward valued skills and behaviors, and create business understanding for employees. The EICP is structured in a way that helps to highlight certain important elements of utility service and to emphasize to employees that they should pay attention to achieving these targets. Making it clear to employees that a portion of their total compensation depends upon their collective ability to meet these targets, communicates clearly to employees the importance of serving customers and encourages them to deliver their best performance. Because the EICP has been designed so that the incentive payments simply bring employee compensation to a competitive market-rate level, a better way to describe this program is that employees are penalized if the targets are not achieved.

Q. Do you believe that the EICP is the reason that the above benefits have been realized?

A. Yes. I believe that the design of the EICP is intended to, and does, make it significantly more likely that these customer benefits will be achieved. By placing a portion of employees' market-based compensation at-risk, they are incentivized to deliver on the EICP goals related to safety, reliability, and employee culture.

Q. Do you believe that any of the metrics included in the EICP are duplicative?

A. No. The metrics have been selected to create a designed, balanced focus on safety, reliability, and employee culture that results in broad customer benefits.

Q. Does this conclude your direct testimony?

A. Yes.

S T A T E O F M I C H I G A N

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the application of **CONSUMERS ENERGY COMPANY** for authority to increase its rates for the distribution of natural gas and for other relief.	)))))	Case No. U-21490

DIRECT TESTIMONY

OF

BRIAN J. VANBLARCUM

ON BEHALF OF

CONSUMERS ENERGY COMPANY

December 2023

Q. Please state your name and business address.

A. My name is Brian J. VanBlarcum, and my address is One Energy Plaza, Jackson, Michigan 49201.

Q. By whom are you employed?

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

Q. What is your position with Consumers Energy?

A. I am a Tax Director in the Company's Corporate Tax Department.

Q. Please briefly describe your educational background.

A. I am a graduate of Western Michigan University where I earned a Bachelor of Business Administration degree in Finance.

Q. Please describe your business experience.

A. I started with the Company in 2004 as a General Accounting Analyst with the Company's Property Accounting team. In 2019, I was appointed to my current position as Tax Director with the Company's Corporate Tax Department.

Q. Are you a certified assessor?

A. I am a Michigan Certified Assessing Officer certified by the State of Michigan's State Tax Commission and a member of the Michigan Assessors Association.

Q. What are your responsibilities as Tax Director?

A. I am responsible for the administration of the Company's real and personal property taxes. This includes: (i) managing the Company's self-declaration of personal property located within the state of Michigan; (ii) overseeing property tax matters concerning the Company's land, generating sites, and other real property; and (iii) supervising tax payments to approximately 1,500 taxing authorities. I am also responsible for the calculation of federal and state tax depreciation related to the Company's fixed assets and the associated deferred income taxes.

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

A. Yes, I sponsored testimony in the following cases:

- Gas Rate Case No. U-15506;
- Electric Rate Case No. U-15645;
- Electric Rate Case No. U-16191;
- Gas Rate Case No. U-16418;
- Electric Rate Case No. U-17087;
- Electric Rate Case No. U-17735;
- Gas Rate Case No. U-17882;
- Electric Rate Case No. U-17990;
- Gas Rate Case No. U-18124;
- Electric Rate Case No. U-18322;
- Gas Rate Case No. U-18424;
- Electric Rate Case No. U-20134;
- Gas Rate Case No. U-20322;
- Gas Rate Case No. U-20650;
- Electric Rate Case No. U-20697;
- Gas Rate Case No. U-21148;
- Electric Rate Case No. U-21224;
- Gas Rate Case No. U-21308; and

- Electric Rate Case No. U-21389.

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

A. My direct testimony identifies the Property Tax Rate for the test year (12 months ending September 30, 2025) and explains how the rate was derived. I am also supporting the amount of test year excess deferred federal income taxes being returned to gas customers as a result of the Tax Cuts and Jobs Act of 2017 ("TCJA") and the Commission's September 26, 2019 Order in the Company's Calculation C Case No. U-20309.

Q. Have you prepared any exhibits to accompany your direct testimony?

A. Yes. I am sponsoring:

Exhibit A-114 (BJV-1)	Development of the Property Tax Rate for the Test Year; and
Exhibit A-115 (BJV-2)	Amortization of Excess Deferred Federal Income Taxes for the Test Year and Tax Reform Regulatory Liability & Amortization.

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

A. Yes.

<u>Development of the Property Tax Rate for the Test Year</u>

Q. What is the Property Tax Rate for the test year?

A. As indicated on Exhibit A-114 (BJV-1), page 1, line 16, the Property Tax Rate for the test year is 0.013862041.

Q. How did you calculate the Property Tax Rate for the test year?

A. The Property Tax Rate for the gas business was calculated using the Company's prorated Gas Property Tax Expense in Exhibit A-114 (BJV-1), page 1, line 10, divided by the total of the 2024 estimated year-end plant-in-service in Exhibit A-114 (BJV-1), page 1, line 11, plus one-half of the estimated 2024 Construction Work in Progress in Exhibit A-114 (BJV-1), page 1, line 14.

Q. What is included in the Gas Property Taxes Paid – 2024 Estimate on Exhibit A-114 (BJV-1), page 1, line 1?

A. The Consumers Energy 2024 taxes paid of $181.4 million on behalf of the gas portion of the business represents estimated property taxes to be paid in 2024.

Q. What is included in the Gas Property Taxes on 2024 Plant Investment on Exhibit A-114 (BJV-1), page 1, line 2?

A. The $16.2 million increase is the estimated property taxes on the 2024 net additions that will be included in the 2025 property tax liability. This is calculated by taking the capital additions, less retirements, times the first year State Tax Commission multiplier table value to recognize a depreciation allowance, which is then multiplied by the statutory reduction of 50% of true cash value to get the assessed value, then multiplied by Consumers Energy's composite millage rate of 50.0387 to obtain the estimated tax amount. This calculation is shown on Exhibit A-114 (BJV-1), page 2, line 9.

Q. What is included in the Gas Property Taxes on Real Property Taxable Value Increases – Inflation on Exhibit A-114 (BJV-1), page 1, line 3?

A. The $0.1 million increase for the Real Property Taxable Value relates to the Michigan Constitution of 1963, Article IX, Section 3, allowing local assessors to raise real property taxable values by the lesser of 5% or the Consumer Price Index ("CPI"). For 2025, the Company's property tax model assumes a CPI rate of 2.7%. This calculation is shown on Exhibit A-114 (BJV-1), page 3.

Q. What is the result of including the Gas Property Taxes on 2024 Plant Investment and the Gas Property Taxes on Real Property Taxable Value Increase on the estimated 2025 property tax amount paid by the gas business?

A. The result of including these additional items is an estimated 2025 property tax amount to be paid for the gas business of $197.7 million as shown on Exhibit A-114 (BJV-1), page 1, line 4.

Q. How is this paid amount converted to an expense amount?

A. Since the Company expenses property taxes based on the fiscal year of the taxing authorities, 50.0% of the 2024 estimated gas property tax payments for Consumers Energy is added to the 2025 estimated gas payments since that amount will be expensed in 2025, while subtracting 50.0% of the 2025 estimated gas payments that will be expensed in 2026, arriving at a total 2025 property tax expense of $189.5 million as shown on Exhibit A-114 (BJV-1), page 1, line 7.

Q. What is the next step in calculating the tax rate for the test year?

A. For the test year, property tax expense was prorated for the period October 1, 2024 through September 30, 2025 using a monthly budgeted sales percentage applied to the 2024 and 2025 estimated annual property tax expense amounts. The result of factoring property tax expense monthly for the test year is a prorated Gas Property Tax Expense of $184.3 million. The Prorated Property Tax Expense for the test year is divided by the 2024 estimated year-end plant-in-service plus one-half of 2024 Estimated Construction Work in Progress to arrive at an average tax rate of 0.013862041.

<u>**Amortization of Excess Deferred Federal Income Taxes for the Test Year**</u>

Q. On September 26, 2019, the Commission issued an Order in the Company's Calculation C Case No. U-20309. What specific issues did the September 26, 2019 Order in Case No. U-20309 address?

A. The Commission's September 26, 2019 Order in the Company's Calculation C Case No. U-20309 authorized the amount and time period under which the Company will refund to gas customers $451,588,000 of excess deferred federal income taxes as a result of the TCJA lowering the corporate income tax rate from 35% to 21%. As part of the settlement terms in Case No. U-21148, the Commission approved an adjustment to reduce this amount by $4,174,259 to correct an overstatement of the TCJA remeasurement. The Commission authorized three different amortization periods: (i) Protected plant balances over an amortization period determined using the average rate assumption method ("ARAM"), (ii) Non-Protected plant balances amortized over 44 years, and (iii) Unprotected non-plant balances amortized over 10 years. Exhibit A-115 (BJV-2), page 2, referenced as Exhibit A-6 (SBM-4) in Case No. U-20309, provides the projected annual amortization of these balances based on the periods approved by the Commission.

Q. What impact did the settlement terms in Case No. U-20650 have on the unprotected non-plant balance?

A. The settlement in Case No. U-20650 accelerated the amortization of the remaining unprotected, non-plant balance to the period October 1, 2021 through September 30, 2022. As of October 1, 2022, the regulatory liability balance has been fully refunded to customers. Therefore, no amortization has been included in this case.

Q. What additional amount of excess deferred taxes related to the TCJA has the Company proposed to refund to customers in this case?

A. As shown on Exhibit A-115 (BJV-2), page 1, line 22, the Company has proposed to refund an additional $3,484,000 of excess deferred taxes ($4,672,000 of regulatory liability after gross-up for taxes) in this case. This amount represents the Company's regulatory liability recorded as of year-end 2021 which was calculated as the difference between the actual amount of excess deferred taxes for the year and the estimated amount included in rates. The Company's most recently filed report to the Case No. U-20309 docket, which calculates the $4,672,000 regulatory balance, is included as Exhibit A-115 (BJV-2), page 3.

Q. Based on the Commission's September 26, 2019 Order in Case No. U-20309 and the additional amount described above, what amount of excess deferred federal income tax has the Company proposed to return to customers in this case?

A. Exhibit A-115 (BJV-2), page 1, provides a calculation of the test year excess deferred federal income taxes included in this case based on the periods approved by the Commission in Case No. U-20309. Overall, the Company reduced Federal Income Tax Expense for the test year by $7.782 million to reflect the amortization periods and amounts discussed above. This amount is shown on Company witness Heather L. Rayl's Exhibit A-13 (HLR-45), Schedule C-8, lines 43, 47, and 48 as TCJA Tracker – U-20309, TCJA Amortization – ARAM, and TCJA – Non ARAM.

Q. Are the excess deferred federal income tax amounts refunded to gas customers in the test year estimates or actuals?

A. The amounts included in this case are estimates as the Commission's September 26, 2019 Order in Case No. U-20309 requires an annual reconciliation of the actual amount of excess deferred federal income tax in a given year and the estimated amount included in rates. The Company will file this reconciliation in the Case No. U-20309 docket by March 31 of each year.

Q. Does this conclude your direct testimony?

A. Yes.

S T A T E O F M I C H I G A N

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the application of **CONSUMERS ENERGY COMPANY** for authority to increase its rates for the distribution of natural gas and for other relief.	)))))	Case No. U-21490

DIRECT TESTIMONY

OF

LINCOLN D. WARRINER

ON BEHALF OF

CONSUMERS ENERGY COMPANY

December 2023

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 36 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")?

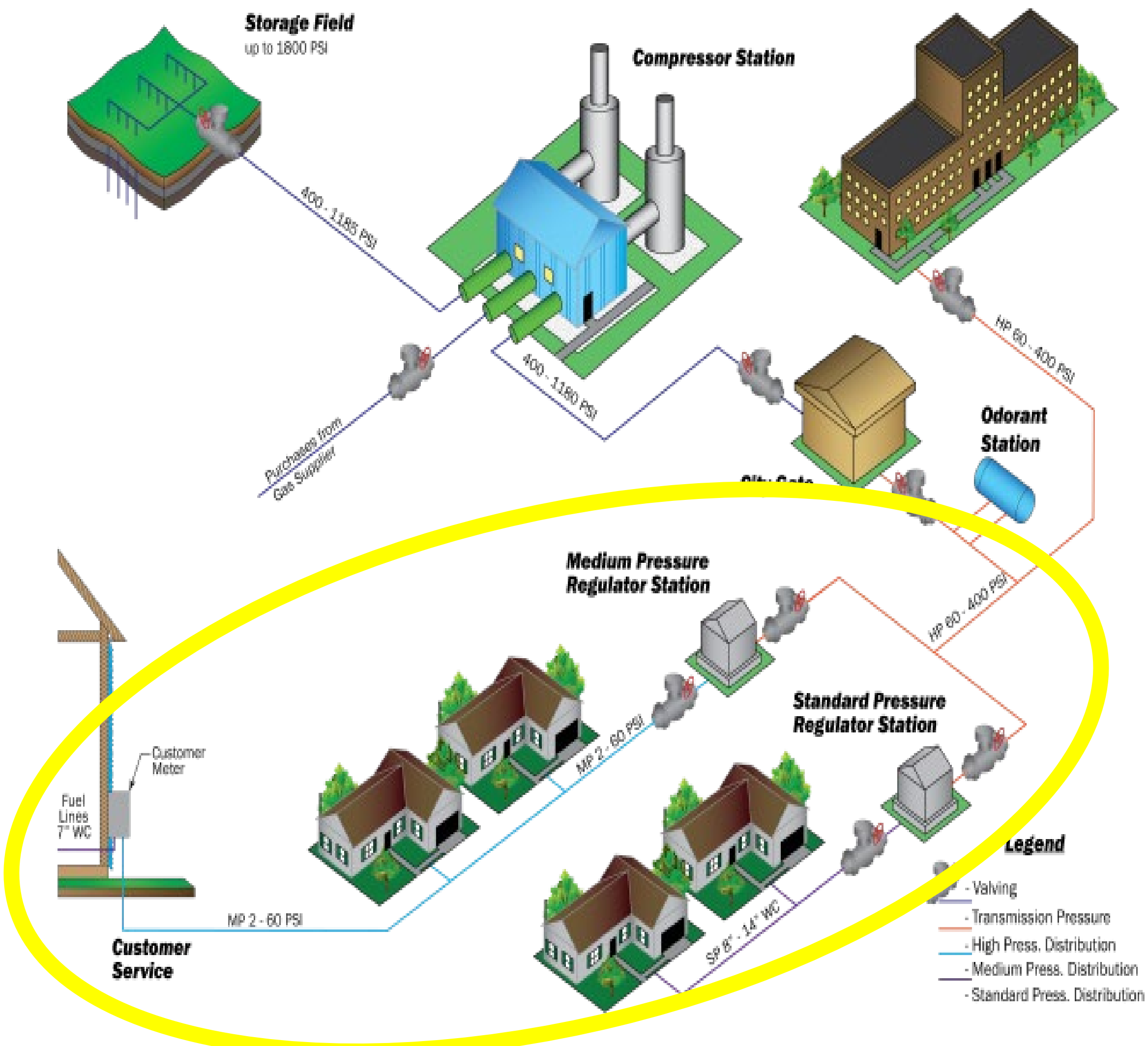
A. Yes. I have provided testimony in the following Case Nos.:

- 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; and
- Case No. U-21308 – December 2022 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-21308)?

A. The capital programs described in my testimony are the same as the capital programs I sponsored in Case No. U-21308, with one exception. The Gas Operations Other Program is sponsored in this case by Company witness Kristine A. Pascarello as part of her testimony and exhibits.

Q. Are you sponsoring any exhibits?

A. Yes. I am sponsoring the following exhibits:

Exhibit A-12 (LDW-1)	Schedule B-5.10	Projected Capital Expenditures, Distribution Plant, Summary of Actual & Projected Gas and Common Capital Expenditures;
Exhibit A-116 (LDW-2)		Actual & Projected Gas Capital Expenditures - New Business Program;
Exhibit A-117 (LDW-3)		Actual & Projected Gas Capital Expenditures - Asset Relocation Program;

Exhibit A-118 (LDW-4)	Actual & Projected Gas Capital Expenditures - Regulatory Compliance Program;
Exhibit A-119 (LDW-5)	Actual & Projected Gas Capital Expenditures – Capacity/ Deliverability Program;
Exhibit A-120 (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 September 30, 2025, which are displayed on Exhibit A-12 (LDW-1), Schedule B-5.10. The total Gas Distribution capital expenditures supported by this direct testimony are as follows:

- Calendar year 2022 actual capital expenditures of $223,619,185, as displayed on line 5, column (b), of Exhibit A-12 (LDW-1), Schedule B-5.10;
- Calendar year 2023 projected capital expenditures of $197,895,936, as displayed on line 5, column (c), of Exhibit A-12 (LDW-1), Schedule B-5.10;
- Nine months ending September 30, 2024 projected capital expenditures of $145,475,493, as displayed on line 5, column (d), of Exhibit A-12 (LDW-1) Schedule B-5.10; and
- Projected test year 12 months ending September 30, 2025 capital expenditures of $265,976,437, as displayed on line 5, column (f), of Exhibit A-12 (LDW-1), Schedule B-5.10.

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 12/31/2022	12 Mos Ending 12/31/2023	9 Mos Ending 9/30/2024	21 Mos Ending 9/30/2024	Projected Test Year 12 Mos Ending 9/30/2025
New Business	74,088	76,533	41,319	117,852	58,090
Asset Relocation	116,504	84,724	67,997	152,720	85,143
Regulatory Compliance	22,832	33,295	31,276	64,571	117,182
Capacity/Deliverability	10,196	3,345	4,884	8,228	5,562
Total Capital	**223,619**	**197,896**	**145,475**	**343,371**	**265,976**

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 $265.976 million are $42.357 million more than the $223.619 million actually incurred in calendar year 2022. The increase or decrease for each program is summarized below:

- New Business: a decrease of $15.998 million, or approximately 21.6%;
- Asset Relocation: a decrease of $31.361 million, or approximately 26.9%;
- Regulatory Compliance: an increase of $94.350 million, or approximately 413.2%; and
- Capacity/Deliverability: a decrease of $4.634 million, or approximately 45%.

As indicated above, the increase in Regulatory Compliance expenditures accounts for most of the increase in test year capital expenditures compared to the 2022 historical actual.

Q. How much of a difference was there between the 2022 actual capital expenditures for these programs and the five-year average amount?

A. The 2018-2022 five-year average amount is $214.2 million, and the 2022 actual amount is $223.6 million, so the 2022 actual capital expenditures were $9.4 million, or 4.3% more than the five-year average. Table 2 provides the actual capital expenditures for 2018 through 2022 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 2018**	**Historical 2019**	**Historical 2020**	**Historical 2021**	**Historical 2022**	**Five Year Historical Average**
New Business	86,944	86,498	87,021	55,373	74,088	**77,985**
Asset Relocation	77,352	106,363	83,973	63,376	116,504	**89,514**
Regulatory Compliance	35,866	46,318	38,354	46,994	22,832	**38,073**
Capacity/Deliverability	19,494	3,560	3,599	6,503	10,196	**8,670**
Total Capital	**219,656**	**242,739**	**212,947**	**172,246**	**223,620**	**214,242**

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 2018-2022.

A. The projected test year capital expenditures of $265.976 million are $51.734 million more than the historical five-year average amount of $214.242 million, which represents an increase of approximately 24%.

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 2018-2022.

A. The projected test year capital amount of $265.976 million exceeds both the 2022 historical actual and the historical five-year average. The increase can be attributed to two specific

Regulatory Compliance projects that account for $69.5 million of the Company's projected test year capital expenditures. These include:

- $53.196 million of test year capital expenditures for the Line 1080 Maximum Allowable Operating Pressure ("MAOP") project; and
- $16.322 million of test year capital expenditures for the Line 1009/1009c I94 to Little Mack, 10 Mile to 11 Mile 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 2023 projections include actual expenditures for January through July of 2023 and estimates of expenditures for August through December of 2023. Projections of annual 2024 and 2025 capital expenditures were used in combination with historical spending patterns to estimate the dollars for the nine months ending September 30, 2024, and the test year period of October 1, 2024, through September 30, 2025. 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 2024 and 2025 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-5.10, 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-116 (LDW-2) through Exhibit A-120 (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. <u>New Business</u>

Q. Please describe the capital expenditures related to the New Business Program as shown on Exhibit A-12 (LDW-1), Schedule B-5.10, 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 2022, and the Company's projections for the years 2023, the nine months ending September 30, 2024, and the 12-month test year ending September 30, 2025, are displayed in total on Exhibit A-12 (LDW-1), Schedule B-5.10 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 12/31/2022	12 Mos Ending 12/31/2023	9 Mos Ending 9/30/2024	21 Mos Ending 9/30/2024	Projected Test Year 12 Mos Ending 9/30/2025
Mains, Services, Meter Stands	72,501	67,384	41,319	108,702	58,090
Large New Business Projects	848	9,150	0	9,150	0
Customer Attachment Program	740	0	0	0	0
Total New Business	**74,088**	**76,534**	**41,319**	**117,852**	**58,090**

Exhibit A-116 (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 8,155 gas new business service connections during calendar year 2023, then 8,318 gas new business service connections in each year starting in 2024. The test year forecast is also 8,318 services. These projections compare closely to the average for the 2018 through 2022 time period of 8,092 gas service installations. The variance between the 2023 projection and the five-year average is 63 services, or about 0.8% more than the five-year average. The variance for 2024 and beyond compared to the five-year historical average is 226 services annually, or about 2.8%.

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

---

[1] The referenced report is available on the Michigan Public Service Commission's website at the following location: https://mi-psc.force.com/sfc/servlet.shepherd/version/download/0688y0000094k46AAA

[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.

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.

The Customer Energy Management Department also monitors the projections of the Michigan Home Builders Association ("HBA of Michigan" or "HBA"). In June of 2023, the HBA of Michigan revised their projections of 2023 calendar year single family home permits to 15,546 units.[4] This was an increase of 23 units, or 0.1% from the HBA of Michigan's original November 2022 forecast of 15,523 units for 2023. The HBA's press release[5] indicates that electrical transformer and other supply-chain shortages have resulted in delays in new housing developments. A modest rebound during the summer and fall is expected to result in a 2023 increase of 6.8% over the total 2022 single family housing permits in Michigan.

The Company's projected service installations for 2023 of 8,155 units reflect an anticipated increase of 436 units over 2022, an increase of approximately 5.6%. Therefore, the service installation projections provided the Company's Customer Energy Management Department reflect slightly lower growth in 2023 than the HBA of Michigan projection.

---

[3] As noted in the footnote above, new gas service installations in 2019 totaled 8,223 units.

[4] Source: www.hbaofmichigan.com press release dated June 29, 2023, "New Home Construction Permits Down 21% YTD"

[5] Press release website address: https://growthzonesitesprod.azureedge.net/wp-content/uploads/sites/3900/2023/07/HBAM-Permit-Forecast.Updated.6.29.23.FINAL_.pdf

The Company also subscribes to economic projections published by S&P Global ("S&P").[6] 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.[7] The June 2023 forecast of total housing starts for the U.S. economy indicates an expectation that 2023 housing starts will be 1.360 million units, then decline to 1.328 million units in 2024, and then increase to 1.409 million units in 2025. Despite the projected decline in 2023, the 2023 to 2025 annual forecasts all exceed the actual 2019 pre-pandemic measure of U.S. housing starts of 1.292 million units as well as the 2016 to 2020 five-year average of 1.264 million units.[8]

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 is experiencing a significant increase in the amount of new business work associated with extending distribution mains in 2023 compared to the 2022 historical

---

[6] S&P Global purchased IHS Markit in early 2022.

[7] Workpaper reference: WP-HLR-44.

[8] 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

year. The extension of distribution mains has required investments of approximately $24.0 million during the first nine months of 2022. 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;
- Manufactured home community developments; and
- Heath 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-21308?

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-21308. A comparison of New Business service attachments in each proceeding are provided below:

Table 4: New Business Program service attachment projections

Description	Historical 2022	Projected 2023	Projected 2024	Projected 2025
Case No. U-21308[9]	8,254	8,667	9,100	N/A
Current Projection (Case No. U-21490)	7,719	8,155	8,318	8,318
Difference (in units)	-535	-512	-782	N/A
Difference (in percent)	**-6.5%**	**-5.9%**	**-8.6%**	**N/A**

[9] Source: Case No. U-21308 Direct Testimony of Company witness Lincoln D. Warriner, page 17, Table 4.

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 2018 through 2022, the Company installed approximately 414 miles of gas main,[10] or an average of approximately 83 miles per year. The gas main installed during the 2022 historical year in this case is 71.2 miles, which is approximately 86% of the five-year average. During the January to September 2023 time frame, the Company installed 52.3 miles of distribution main, and will likely install more than 70 miles of distribution main for the full year of 2023.[11]

Q. What was the actual average New Business Program cost per service installed during the 2022 historical year?

A. I have calculated the average New Business Program cost per service installed during 2022 to be $9,492.66. This number was calculated using the total 2022 actual New Business Program capital expenditures of $74,087,970, less the expenditures for New Business Major Projects of $814,109; or $73,273,861 divided by the number of New Business services installed during 2022 of 7,719 units.

Q. What are the projected average New Business Program cost per service installed for 2023, 2024, and 2025?

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

---

[10] Historical gas main installation miles: 2018: 137.0 miles; 2019: 91.3 miles; 2020: 61.6 miles; 2021: 52.8 miles; 2022: 71.2 miles. The five-year average is calculated as follows: (137.0 + 91.3 + 61.6 + 52.8 + 71.2)/5 = 413.9/5 = 82.78

[11] The 2023 estimate of more than 70 miles is based on October 2022 through September 2023 actual experience of 71 miles (or 374,068 feet).

also documents the calculation of the test year dollars for the New Business Program. The projected capital expenditures for October through December of 2024 are 26.5% of the 2024 annual projection, and the projected capital expenditures for January through September of 2025 are 73.5% of the 2025 annual projection.

Table 5: New Business Units and Unit Costs (in Thousands of Dollars)

Description	**Actual 2022**	**Projected Calendar Year 2023**	**Projected Calendar Year 2024**	**Projected Calendar Year 2025**	**Projected Test Year**
Total New Business Dollars (in Thousands; excluding Large New Business projects)	**$73,274**	**$67,384**	**$56,252**	**$58,755**	
Service Installation Units	7,719	8,155	8,318	8,318	
Average Unit Cost (in $)	$9,492.66	$8,262.86	$6,762.74	$7,063.54	
Test Year Dollar Detail:					
Calendar Year amounts included in the Projected Test Year (in Thousands)			**$14,934 (October through December)**	**$43,157(January through September)**	**$58,090**

Q. Please explain the difference between the projected unit costs shown above, and the 2022 actual unit cost of $9,492.66.

A. The 2025 projected unit cost of $7,063.54 is less than what would be expected if S&P forecasts of Consumer Price escalation were used to project the 2022 unit cost forward out to 2025. The 2025 projected unit cost in a Consumer Price escalation scenario would be

$10,402.22, which is an increase of $3,338.68 per unit, or 47.3% from the Company's 2025 projection.[12]

The 2024 projected unit cost of $6,762.74 is less than what would be expected if S&P forecasts of Consumer Price escalation were used to project the 2022 unit cost forward out to 2024. The 2024 unit cost in a Consumer Price escalation scenario would be $10,158.42,[13] which is an increase of $3,395.68 per unit, or 50.2% from the Company's 2024 projection.

The 2024 projected unit cost of $6,762.74 is equivalent to decreasing the 2022 actual average unit cost at 15.6% per year.[14] The 2024 projected unit cost are lower than the 2022 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-21308, which estimated test year ending September 30, 2024 New Business Program capital expenditures of $56.1 million.[15]

The 2023 projected unit cost of $8,262.86 is less than what would be expected based on S&P forecasts of Consumer Price escalation were used to project the 2022 unit cost forward to 2023. The 2023 projected unit cost in an updated Consumer Price

---

[12] The projected Consumer Price inflation projections for 2023, 2024, and 2025 respectively are 4.2%, 2.7%, and 2.4%. The 2022 actual unit cost of $9,492.66 x 1.042 (2023 Consumer Price Index "CPI" growth) x 1.027 (2024 CPI growth) x 1.024 ((2025 CPI growth) = 10,402.22. Alternatively, the average of the 2023, 2024, and 2025 Consumer Price inflation projections is 3.1%; therefore, the calculated 2025 unit cost estimate based on the average inflation projection would be $9,492.66 x 1.031 x 1.031 x 1.031 = $10,403.13. The CPI growth rates used in this calculation are documented in WP-HLR-44.

[13] 2022 actual unit cost of $9,492.66 x 1.042 (2023 CPI growth) x 1.027 (2024 CPI growth) = $10,158.42. The CPI growth rates used in this calculation are documented in WP-HLR-44.

[14] 2022 actual unit cost of $9,492.66 x 0.84405 x 0.84405 = 6,762.76.

[15] Case No. U-21308, Direct Testimony of Staff witness Creisher, page 16, line 6.

escalation scenario would be $9,891.35, which is an increase of $1,628.49 per unit, or 19.7% from the Company's 2023 projection.

The 2023 projected unit cost of $8,262.86 is 13% less than the 2022 actual unit costs. This projection includes seven months of actual expenditures and five months of projected expenditures and reflects decreases in various contractor costs that are being realized during 2023.

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. The settlement agreement approved by the Commission's Order in Case No. U-21148 required the Company to (1) meet with Michigan Environmental Council, Natural Resources Defense Council, and Sierra Club (collectively, "MNS") and Staff to review and update line extension assumptions used to determine the contributions required from new customers, and (2) transition to a new line extension model that is transparent and capable of being shared with stakeholders for review by the end of 2022. Has the Company fulfilled these requirements of that settlement agreement?

A. Yes, representatives from the Company met with MNS and Staff in November 2022 to review the Company's analysis and recommendations regarding updates to customer contributions for installation of new connections. The development of the new line extension model was completed by the end of 2022. Changes in the contributions required from customers were made effective on March 1, 2023, as required by Rule C8 of 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 2022 are primarily service installation costs, and are detailed on line 3, column (b) of Exhibit A-116 (LDW-2). Actual CAP program service installation costs incurred during 2023 are included as part of "Mains Services & Meter Stands – Dist" on line 1, column (c) of Exhibit A-116 (LDW-2).

Q. Please describe the projects in the Large New Business sub-program, represented on Exhibit A-116 (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 is 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. Currently there are no additional new projects included in the projections for this sub-program for 2023 through 2025. New requests for load, however, can be received at any time, meaning the Company may add projects to this program as customer requests materialize. Historically, the Company has invested $74.3 million since 2018 to construct gas service facilities for large customers.[16]

Gas service facilities that have been installed as required to meet customer service requirements include high-pressure gas mains, city gate 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.

Table 6: Large New Business Capital Expenditures – History (in thousands of dollars)

Program Description	Historical 2018	Historical 2019	Historical 2020	Historical 2021	Historical 2022	2023 January through September
Lansing BW&L Delta Energy Park Project	449	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	0
RNG Facility					4	4,376
Battery Manufacturing Facility					67	4,402
Other Large New Business Projects	10,337	-4,005	1,601	-51	65	12
Total Capital	**10,786**	**17,914**	**33,440**	**2,406**	**848**	**8,911**

Q. Please explain why the Company is not projecting any expenditures in 2024 and 2025 related to Large New Business projects.

A. The rationale for not including projections of expenditures in this proceeding is the same as it was in Case No. U-21308. Due to the potentially costly nature of extending mains and installing services to large industrial and commercial facilities, the Company only

[16] The historical period referred to in this statement includes January 2018 through September 2023.

estimates costs within rate cases for projects that have a reasonable certainty regarding the scope and timing of work to be performed. At this time, the Company believes it is likely that large projects will develop during 2024 and 2025, but it is premature to seek approval for recovery of those projects at this time. It is, however, reasonable for the Company to request approval to include the capital expenditures actually incurred during calendar year 2022 and the projected 2023 costs related to the projects outlined in Table 6 above.

Q. Please conclude your testimony regarding the Company's New Business Program.

A. Based on the evidence provided above, it is my opinion 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-21308, and the unit cost projections for the New Business Program are lower than the historical 2022 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-116 (LDW-2).

B. <u>Asset Relocation</u>

Q. Please describe the capital expenditures related to the Asset Relocation Program as shown on Exhibit A-12 (LDW-1), Schedule B-5.10, 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-117 (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 12/31/2022	12 Mos Ending 12/31/2023	9 Mos Ending 9/30/2024	21 Mos Ending 9/30/2024	Projected Test Year 12 Mos Ending 9/30/2025
Asset Relocation – Civic Improvement	103,075	72,583	57,479	130,062	70,637
Asset Relocation - Reimbursable	13,429	12,141	10,517	22,658	14,506
Total Asset Relocation	**116,504**	**84,724**	**67,997**	**152,720**	**85,143**

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 upgrade, 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 has been 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, avoids third party damage to non-vintage facilities, and reduces 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. See Exhibit A-43 (NPD-1).

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 2018 to 2022 historical years have totaled \$393.2 million. Over 230 miles of distribution main has been installed and more than 11,900 services have been replaced during the 2018 to 2022 time period.[17] The average annual capital investment has been approximately \$78.6 million.

In most cases, the civic improvement projects involve replacement of metallic facilities with plastic pipe. For example, during the 2018 to 2022 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 5.8% of the civic improvement project main installed during the 2018 to 2022 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

[17] 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.

historical experience. The Company experienced workload increases during 2022 compared to both 2020 and 2021 as well as compared to the five-year average.

Table 8: Asset Relocation – Civic Improvement Project History[18]

	2018	2019	2020	2021	2022	5-Year Average
Projects completed	185	202	124	152	170	**167**
Feet of Distribution Main Installed	301,215	254,605	169,202	195,305	297,246	**243,515**
Services Replaced	2,401	2,924	1,729	2,377	2,494	**2,385**

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[19] 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.[20] 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.[21] In addition, the City of Eastpointe's 9 Mile Road reconstruction and water

[18] Source: Attachment 9 to Gas EIRP Annual Report.

[19] The 2023 amount includes actual capital expenditures for January 2023 through September 2023.

[20] https://www.detroitnews.com/story/news/local/macomb-county/2022/09/15/project-rebuild-mound-road-nearly-40-complete/10386613002/, accessed 11/7/2022.

[21] https://www.michigan.gov/dnr/places/state-trails/iron-belle, accessed 9/18/2023.

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.[22]

Table 9: Asset Relocation – Civic Improvement Large Project History (in Thousands of Dollars)

	Project Reference	2017	2018	2019	2020	2021	2022	2023 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	$1,620	$1	-$5	
Marion Ave	18972					$3,755	$146	$24
Oakland Drive	17037				$3,879	($1)	$39	$49
Mound Rd 13 to 14 Mile	19952						$5,129	$39
Mound Rd 11 to 13 Mile	20136						$1,491	$8,762
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
Lapeer Rd Burton	20993						$3,848	$153
Passolt St	19624						$4,996	$5
Atlas Iron Belle Trail	19919						$56	$7,864

[22] https://www.macombdaily.com/2023/03/05/modern-9-plan-encompasses-more-than-road-repaving/, accessed 11/1/2023.

US 127 & 223	20824							$3,198
Wayne Rd Bridge Replacement	20855						$303	$2,664
9 Mile Road Eastpointe	19765 21012						$92	$7,735
Other Projects	Various	$50,779	$59,514	$80,406	$53,524	$49,316	$81,375	$41,975
Total Asset Relocation - Civic		**$58,236**	**$68,417**	**$90,700**	**$74,653**	**$56,401**	**$103,075**	**$73,175**

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 $70,637 reflects the Company's expectation that 23.69% of the 2024 calendar year capital investments and 76.31% of the 2025 calendar year capital investments will occur during the October 2024 to September 2025 time period.

Table 10: Asset Relocation – Civic Improvement Projections (in Thousands of Dollars)

Description	**Actual 2022**	**Projected Calendar Year 2023**	**Projected Calendar Year 2024**	**Projected Calendar Year 2025**	**Projected Test Year**
Total Asset Relocation – Civic Improvement (Thousands of Dollars)	**$103,075**	**$72,583**	**$69,149**	**$70,939**	
Test Year Dollar Detail:					
Calendar Year amounts included in the Projected Test Year (in Thousands)			**$11,669 (October through December)**	**$58,968 (January through September)**	**$70,637**

The calendar year 2025 projection of $70.939 million is a decrease of $32.136 million, or approximately 31% less, compared to the 2022 actual capital expenditures. Table 11 indicates the Company expects to install 202,460 feet of distribution main during 2025, which is an approximately 32% decrease in workload compared to 2022. Therefore, the difference between the calendar year 2025 capital investment and the 2022 historical actual capital investment is due to decreases in projected work.

The calendar year 2024 projection of $69.149 million is a decrease of $33.926 million, or approximately 32.9% less, compared to 2022. Table 11 indicates that the Company expects to install 202,460 feet of distribution main during 2024, which is an approximately 32% decrease in workload compared to 2022. The difference between the calendar year 2024 capital investment and the 2022 capital investment, therefore, is due to decreases in projected work.

The calendar year 2023 projection of $72.583 million is a decrease of $30.492 million, or approximately 29.6% from 2022. Table 11 indicates that the Company expects to install 196,563 feet of distribution main during 2023, which is an approximately 33.9% decrease in workload. Therefore, the difference between the calendar year 2023 capital investment and the 2022 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 2023 of $73.175 million. The Company is experiencing increases in construction contractor costs during 2023 and will exceed the 2023 projection included in my exhibits by approximately $8 million.

Q. Please summarize the work that the Company expects to complete during the 2023 through 2025 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 projections include the Mound Road reconstruction project, the Atlas Iron Belle Trail project, the 9 Mile Road Eastpoint project, the Romeo Plank project, and the M-20/Prairie Drain MDOT project.

Table 11: Asset Relocation – Civic Improvement Projection Details

	Actual 2022	2023 (Projected)	2024 (Projected)	2025 (Projected)
Projects	170	124	128	128
Feet of Distribution Main to be Installed	297,246	196,563	202,460	202,460
Asset Relocation Services to be Replaced	2,494	1,222	1,259	1,259

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. Additionally, 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.

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-117 (LDW-3), line 1, the capital expenditures for the Asset Relocation – Civic Improvement Program were $103,075,238 in 2022, and are projected to be:

- $72,583,000 for the calendar year 2023;
- $57,479,000 for the nine months ending September 30, 2024; and
- $70,637,000 for the test year ending September 30, 2025.

These projections are based upon recent history, projections of increased federal and state funding for infrastructure improvements, and on 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 $54.3 million for more than 24,400 orders from 2018 through 2022, for a historical five-year average of approximately $10.9 million annually. During 2023, the Company invested approximately $6.6 million for more than 3,250 orders during the first seven months of the year and is projecting a total 2023 investment of $12.1 million because of slightly lower requests for relocation work and lower damage replacements being experienced by the Company during 2023. The $12.1 million projected for 2023 is approximately the same as the $12.3 million of annual average investment experienced by the Company during 2018 and 2019.

Table 12: Asset Relocation – Reimbursable sub-program Details (in Thousands of Dollars)

	2018	2019	2020	2021	2022	2023 (Jan - Jul)
Customer Requested Relocations	$8,266	$9,338	$7,260	$5,888	$11,526	$6,084
Damage Replacements	$669	$1,570	$1,685	$1,473	$1,898	$515
Large Customer Requested Relocation Project		$4,755	$11			
Other			$364	-$386	$4	$5
Total Asset Relocation – Reimbursable	**$8,935**	**$15,663**	**$9,320**	**$6,975**	**$13,429**	**$6,604**

The 2022 actual costs and future period projections for this sub-program are reflected on Exhibit A-117 (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 $13,428,566 in 2022 and were $6,453,223 higher than 2021 capital expenditures for this sub-program.

Q. Why are the 2022 actual amounts for the Asset Relocation – Reimbursable sub-program higher than the 2021 actual amounts?

A. The 2022 actual amount is higher than 2021 due to the following reasons:

- Customer Requested Relocation work order volume increased by approximately 34% in 2022 compared to 2021, and required $5.638 million more investment due to customer requests for service, main, and meter stand relocations in 2022;
- Damage Replacement work order volume increased by less than 1% in 2022 compared to 2021, but required $0.425 million more investment due to higher main replacement work order costs in 2022; and
- The timing of reimbursements in 2021 for work that was completed in 2020 results in a higher capital investment of $0.382 million in 2022 compared to 2021.

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 $14,505,720 includes $3,264,790 for October through December 2024 and $11,240,930 for January through September 2025. 76.31% of the 2025 annual forecast of $14,730,316 and 23.69% of the 2024 annual forecast of $13,782,182 are expected to occur in the test year based on historical timing of expenditures within this sub-program.

The 2025 calendar year forecast of $14,730,316 includes projected customer requested relocation investments of $12,713,567 and investments to correct damages of $2,016,749. The increase in 2025 compared to the 2022 calendar year forecast anticipates cost escalation and increasing requests for customer requested relocation work.

The 2024 calendar year forecast of $13,782,182 includes projected customer requested relocation investments of $11,887,538 and investments to correct damages of $1,894,643. The 2024 forecast anticipates cost escalation and increasing requests for customer requested relocation work from the 2023 forecast.

The 2023 calendar year forecast of $12,141,041 includes actual investments for the first seven months of 2023 in the amount of $6,604,216 and projected investments for the last five months of 2023 in the amount of $5,536,825. The 2023 calendar year forecast is $1,287,525 less than the 2022 historical year amount, and about the same as historical average investments during 2018 and 2019.

Q. Please summarize the Company's projections for the Asset Relocation – Reimbursable sub-program?

A. As shown on Exhibit A-117 (LDW-3), line 2, the capital expenditures for the Asset Relocation – Reimbursable sub-program were $13,428,566 in 2022, and are projected to be:

- $12,141,041 for the calendar year 2023;
- $10,517,390 for the nine months ending September 30, 2024; and
- $14,505,720 for the test year ending September 30, 2025.

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. <u>Regulatory Compliance</u>

Q. Please describe the capital expenditures relating to the Regulatory Compliance Program shown on Exhibit A-12 (LDW-1), Schedule B-5.10, 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 $22,831,579 in 2022, and are projected to be $33,294,536; $31,276,325; and $117,181,609 for the years 2023; the nine months ending September 30, 2024; and the test year ending September 30, 2025, 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-5.10. A further breakdown of the Regulatory Compliance Program expenditures is shown on Exhibit A-118 (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 12/31/2022	12 Mos Ending 12/31/2023	9 Mos Ending 9/30/2024	21 Mos Ending 9/30/2024	Projected Test Year 12 Mos Ending 9/30/2025
Regulatory Base - Distribution	$2,450	$0	$0	$0	$0
Meters	$11,559	$21,826	$17,176	$39,001	$24,732
MAOP Distribution	$240	$2,893	$7,203	$10,096	$82,644
Cathodic - Distribution	$8,583	$8,576	$6,898	$15,474	$9,805
Total Regulatory Compliance	**$22,832**	**$33,295**	**$31,276**	**$64,571**	**$117,182**

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-118 (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 expenditures detailed on Exhibit A-118 (LDW-4), line 2, also include manufacturer installed gas meter communication modules, manufacturer installed gas corrector units, and testing equipment in 2022. The 2023 through 2025 expenditures for gas meter communication modules and gas corrector units will be further discussed below.

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: 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 29.05% of the 2024 calendar year projection and 70.95% of the 2025 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

	2022 Actual	2023 Projection	2024 Projection	2025 Projection	Projected Test Year
Meter Units	21,152	37,003	42,399	42,219	42,399
Unit Cost	546	590	571	591	583
Total Meter Cost	**$11,558,636**	**$21,825,566**	**$24,209,374**	**$24,946,678**	**$ 24,732,461**

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

	2018 Actual	2019 Actual	2020 Actual	2021 Actual	2022 Actual
Meter Units	65,471	67,023	58,997	49,759	21,152
Unit Cost	355	435	419	503	546
Total Meter Cost	**$23,216,076**	**$29,132,703**	**$24,742,799**	**$25,022,976**	**$11,558,636**
Correctors	1,070	1,135	1,460	3,832	
Unit Cost	1,108	1,316	1,383	1,331	
Total Corrector Cost	**$1,185,438**	**$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	**$24,401,514**	**$31,480,341**	**$26,787,777**	**$30,144,463**	**$11,558,636**

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 2024, 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.[23] 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 sixteen projects to date, representing approximately 22.77 miles of distribution main installation, and these sixteen projects are listed in Table 8 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. Sixteen projects will have capital expenditures during 2023, 2024, and 2025 as shown in Table 17 below:

[23] 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)	Construction Completion Year
21948 & 21250	Line 1080, West from Kalamazoo	2,068	8,926	58,983	2026
22861 & 22862	Line 1022, Airport CG to State Rd & State Rd to W Grand River			5,290	2027
22781	Line 1041, Lapeer Rd	250	0	544	2028
TBD	Line 1002c, Phase 1, Coolidge to 11 Mile & Dequindre	465	1,079	4,682	2026
21676	Line 1093, Shattuck Rd	110	0	2,695	2026
21788	Line 1009, Huron Park to I-94		4,200	600	2024
22511	Line 1022f, Vermontville		0	209	2025
22157	Line 1009/1009c I-94 to Little Mack, 10 Mile to 11 Mile		1,500	15,024	2025
22494	Line 1009c, 9 Mile to 10 Mile		100	1,500	2026
22702	Line 1006, Groebel Dr to Mound Rd			600	2026
22150	Line 1002f, Macomb ITC Corridor		210	1,092	2025
22409	Line 1020, Greenfield Rd			409	2025
21674 & 21675	Line 1087b, E Isabella Rd		700	5,780	2025
TBD	Line 1026f, Mt Hope			785	2026
TBD	Line 1026i, MSU PP			50	2026
22532	Line 1090n, Davis St			284	2025
Total 2023/2024/2025 Projection		**$2,893**	**$16,716**	**$98,529**	

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 of 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[24] 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.[25] The Company, however, cannot meet current deliverability requirements at this new specified operating pressure. Options to augment

---

[24] Definition of gas "deliverability": the ability of a natural gas service provider to meet its customers' needs based on seasonal requirements and operating conditions.

[25] 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 and 2026.

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. The Company has adequate documentation to operate the line at the lower pressure per 49 CFR 192.619(c) and need 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 are on-schedule to be 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 will take place during 2025 and 2026. 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 is also scheduled to begin in 2023. Activities to be completed during 2023 include survey and project design for a half-mile main replacement. Project construction is planned for 2024. This replacement will ensure that the company is in compliance with 49 CFR 192.624. The Line 1009 Huron Park to I-94 line segment was installed in 1969 and is approximately 54 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. In order to minimize the impact of pressure testing, pressure reduction, and material testing, the Company believes that it is 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. The Line 1009/1009c I-94 to Little Mack, 10 Mile to 11 Mile project line segment was installed in 1969 and is approximately 54 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.

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 41 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.

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 52 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.

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 19 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.

Q. Please explain the Line 1087b E Isabella Rd project.

A. The Line 1087b E Isabella Rd project scope includes 0.54 mile of 12" diameter main installation to replace an existing 8" diameter existing main segment. Approximately half of this line segment was installed during the 1970s and the rest 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 E Isabella Rd project.

Q. Please explain the Line 1009c, 9 Mile to 10 Mile project.

A. The Line 1009c, 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 1009c, 9 Mile to 10 Mile line segment was installed in 1969 and is approximately 54 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 1009c, 9 Mile to 10 Mile project.

Q. Please explain the Line 1002c, Phase 1 Coolidge to 11 Mile & Dequindre project.

A. The Line 1002c, Phase 1 Coolidge to 11 Mile & Dequindre project scope includes 1 mile of 24" diameter main installation to replace a similar sized existing main segment. The total project scope for Line 1002c includes 8.5 miles of main replacement. The existing Line 1002c, Phase 1 Coolidge to 11 Mile & Dequindre line segment was primarily installed in 1959 and 1960 and is approximately 63 or 64 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, 9 Mile to 10 Mile project.

Q. Please explain the Line 1022 Airport CG to State Rd & State Rd to W Grand River project.

A. The Line 1022 Airport CG to State Rd & State Rd to W Grand River project scope includes 4.0 miles of 16" diameter main installation to replace a similar sized existing main segment. The existing Line 1022 Airport CG to State Rd & State Rd to W Grand River was primarily installed in 1963 and is approximately 60 years old. One additional segment was installed in 1980 and is 43 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 CG to State Rd & State Rd to W Grand River project.

Q. Please explain the Line 1041 Lapeer Rd project.

A. The Line 1041 Lapeer Rd project scope includes 4.1 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 56 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.

Q. Please explain the Line 1093 Shattuck Rd project.

A. The Line 1093 Shattuck Rd project scope includes 1.72 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 56 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.

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 64 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.

Q. Please explain the Line 1026f Mt Hope project.

A. The Line 1026f Mt Hope project scope includes 0.759 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 25 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.

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 53 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.

Q. Please explain the Line 1090n Davis St project.

A. The Line 1090n Davis St project scope includes 0.028 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 21 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.

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-118 (LDW-4), line 4, the capital expenditures for this sub-program were $8,582,806 in 2022, and are projected to be $8,575,878 in 2023; $6,898,264 for the nine months ending September 30, 2024; and $9,805,089 for the 12 months ending September 30, 2025, 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. The galvanic anode systems include 17- and 20-pound magnesium anodes that are installed near the main to attract corrosion to the anodes as opposed to the pipe. 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. The Company plans to install 336 RMUs during the 2025 to 2028 time period, in addition to the 559 that are already in service. RMU installations are expected to be complete during 2028. 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. Installing RMUs reduces the number of required physical visits of each rectifier. This will help reduce the carbon footprint caused by driving to each of these rectifiers and will keep 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, thus improving the integrity of the distribution system. RMU devices allow for the Company to remotely interrupt rectifiers to perform cathodic surveys and testing. Exhibit A-118 (LDW-4), line 4, provides further details of the expenditures included in this program.

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 $33.225 million in the Cathodic Protection Distribution sub-program during 2018-2022. The annual investment averaged $6.645 million per year over that time period. Annual amounts for each year were:

- 2018 historical actual: $5,961,948;
- 2019 historical actual: $5,039,720;
- 2020 historical actual: $6,663,545;
- 2021 historical actual: $6,976,687; and
- 2022 historical actual: $8,582,806.

Q. What portion of the historical investments in the Cathodic Protection Distribution sub-program represent investments in RMU Installations?

A. The Company invested $2.607 million in the Cathodic Protection Distribution sub program during 2018-2022 for RMU Installations. The annual investment averaged $0.521 million per year over that time period. Annual amounts for each year were:

- 2018 historical actual: $113,036;
- 2019 historical actual: $608,746;
- 2020 historical actual: $532,356;
- 2021 historical actual: $720,208; and
- 2022 historical actual: $632,899.

Q. What portion of the historical investments in the Cathodic Protection Distribution sub-program represent investments in Rectifier and Groundbed installations and replacements?

A. The Company invested $6.771 million in the Cathodic Protection Distribution sub program during 2018 to 2022 for Rectifier and Groundbed installations and replacements. The annual investment averaged $1.354 million per year over that time period. Annual amounts for each year were:

- 2018 historical actual: $1,171,721;
- 2019 historical actual: $1,191,788;
- 2020 historical actual: $1,001,186;
- 2021 historical actual: $1,185,666; and
- 2022 historical actual: $2,220,388.

Q. What portion of the historical investments in the Cathodic Protection Distribution sub-program represent investments in other capital repairs?

A. The Company invested $23.847 million in the Cathodic Protection Distribution sub-program during 2018 to 2022 for other capital repairs. The annual investment averaged $4.769 million per year over that time period. Annual amounts for each year were:

- 2018 historical actual: $4,677,192;
- 2019 historical actual: $3,239,186;
- 2020 historical actual: $5,130,002;
- 2021 historical actual: $5,070,813; and
- 2022 historical actual: $5,729,519.

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 \$2,664,361, or 27.86%, of the calendar year 2024 forecast and \$7,140,728, or 72.14%, of the calendar year 2025 forecast. The test year total of \$9,805,089 is 14.2% higher than the 2022 actual capital investment and is approximately 47.6% higher than the five-year average amount of \$6,644,941. The projected increases reflect increasing materials and contractor costs that have been experienced during 2022 and 2023.

The calendar year 2025 forecast for the Cathodic Protection Distribution sub-program is \$9,898,737. This forecast includes \$0 for RMU installations, \$956,616 for Rectifier and Groundbed installations and replacements, and \$8,942,121 for other capital repairs. The 2025 calendar year forecast is 15.3% more than the 2022 historical actual investment, and approximately 49.0% more than the 2018 to 2022 historical average. Increasing material and contractor costs are the primary reasons for projections being higher than the 2022 historical actual and the historical five-year average.

The calendar year 2024 forecast for the Cathodic Protection Distribution sub-program is \$9,562,625. This forecast includes \$0 for RMU installations, \$933,223 for Rectifier and Groundbed installations and replacements, and \$8,629,402 for other capital repairs. The 2024 calendar year forecast is 11.4% more than the 2022 historical actual investment, and approximately 43.9% higher than the 2018 to 2022 historical average.

Increasing material and contractor costs are the primary reasons for projections being higher than the 2022 historical actual and the historical five-year average.

The calendar year 2023 forecast of $8,575,878 includes actual expenditures for the January through July period of $7,445,985 and projected expenditures for the August through December period of $1,129,892. The 2023 calendar year forecast is $6,928 less than the 2022 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-5.10, line 4.

A. As shown on Exhibit A-12 (LDW-1), Schedule B-5.10, the capital expenditures the Company experienced in 2022, and is projecting for the years 2023, the nine months ending September 30, 2024, and the test year ending September 30, 2025, are $10,195,833; $3,344,560; $4,883,682; and $5,561,961, 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 12/31/2022	12 Mos Ending 12/31/2023	9 Mos Ending 9/30/2024	21 Mos Ending 9/30/2024	Projected Test Year 12 Mos Ending 9/30/2025
Augment	10,195	3,345	4,884	8,228	5,562
Total Capacity/ Deliverability	**10,195**	**3,345**	**4,884**	**8,228**	**5,562**

Exhibit A-119 (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 2018 through 2022, the Company has invested over $43.3 million in distribution system Augment projects, as summarized in the following table:

Table 19: Historical Actual Augment Investments by Year

	2018 Actual	**2019 Actual**	**2020 Actual**	**2021 Actual**	**2022 Actual**
Caledonia HP Phase 1	$566,791	$13,613	$488		
Caledonia HP Phase 2	$172,330	$10,319			-$512
Caledonia HP Phase 3	$19,323,678	$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
Imlay City Rd & Lk Pleasant					$1,626,475
W Sanilac Rd					$1,032,909
Other Projects	-$569,187	$1,811,393	$1,784,195	$2.501,265	$1,514,431
Total Augment	**$19,493,612**	**$3,559,955**	**$3,598,945**	**$6,503,025**	**$10,195,833**

The average historical annual investment for 2018 through 2028 is approximately $8.7 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 involves the replacement of undersized HP pipe with properly sized main, which will increase the supply of gas to an area north of Midland.

Q. Can you describe the Augment investments included in this filing?

A. There are several projects planned for 2023 through 2025 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), Climax City Gate (44th Street project high pressure main installation), and Coleman-Beaverton City Gate (the Shaffer Road and Beaverton projects high pressure main installation). The Climax City Gate (44th Street project high pressure main installation) project is the largest augment project being constructed during 2023. Construction will be completed during the 2024 calendar year. This project is necessary to increase the capacity of the system serving areas to the north of Climax extending to the Gun Lake area. These projects as well as several other smaller projects will require a projected total investment of $15.2 million over that time period.

Examples of augmentation projects currently planned for 2024 and 2025 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 in order to reduce risks of low pressure. The project is planned for construction during 2026.

- A new two-inch station is planned for construction during 2024 at Freeman and Dale roads in Midland to build permanent replacements for temporary facilities that were installed in place of infrastructure that was damaged during flooding in 2020. The new station will provide additional supply from the north of Midland and improve the existing infrastructure.

- A project is planned to install approximately 1100 feet of six-inch plastic medium pressure main on Belsay Rd and connect 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 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 5800 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 is planned for 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 is planned for construction during 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-120 (LDW-6).

A. Exhibit A-120 (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-21148.

Q. Can you explain why columns (c), (e), and (f) of Exhibit A-120 (LDW-6) do not contain any data?

A. Yes, the information for column (c), the "Last Rate Case Approved Spending Plan Case No. U-21308," cannot be provided because Case No. U-21308 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. <u>IT PROJECTS</u>

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 Nominations Replacement Solution** project requires $816,330 in capital and $134,758 in O&M in the test year. The Gas Nominations Replacement Solution project will replace the existing gas nominations application with a system that is capable of scheduling and tracking the receipt and redelivery of all the natural gas supply that flows onto and through the Company's gas transmission system to customers. The current gas nominations application has experienced software and vendor support issues since its original implementation including major security risks, inadequate vendor support and issue response time, user inefficiencies and reporting issues, and various technical difficulties that make upgrades and contract administration challenging. Some of the problems have created waste by reverting to manual workarounds. The ongoing issues create a risk that can result in a disruption to the scheduling and tracking of natural gas supply, which in turn may create customer safety risks, result in breaches of confidential customer data, cause significant financial harm, or could cause damage to the Company's reputation. The Gas Nominations team is seeking a replacement application that will provide the full functionality required to maintain supply to customers and address the issues identified with the current application. The project will add value by: (1) mitigating the security risk associated with the existing software; (2) improving response to abnormal situations; and (3) reducing end-user inefficiencies. In addition, the project will create value by eliminating waste and manual steps to create accurate reporting for gas suppliers to change gas allocations for each gas supplier, to support the implementation of the Operational Flow Order provisions in tariffs, and to update Gas Transportation contract values required by tariff. The scope of this project includes: (1) replacing the existing gas nominations application; (2) developing reporting capability based on standard in-house software; and (3) retiring the legacy system (hardware and software). Alternatives considered include: (1) Upgrade the existing application to the latest version. Option 1 was not selected because it requires a significant investment, does not mitigate security risks, and does not meet analytics, reporting, usability, and accessibility needs; (2) Develop a custom in-house solution. Option 2 was not selected due to the complexity of the needed solution and the resources that would have to be involved; and (3) Replace the existing application with a standard software offering, which may be a cloud offering. Option 3 was selected to increase functionality and minimize security risks inherent in the existing software. If this project is not completed then the inefficiencies, administrative challenges, and major system security risks of not meeting IT standards identified above would not be addressed.

- The **Gas Transmission and Distribution ("T&D") Historian** project requires $296,002 in capital and $56,850 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 Leak Asset and Work Management** project requires $383,129 in capital and $40,527 in O&M in the test year. The project will implement functionality to automate gas leak compliance tasks and track all gas leak activity in the Gas Geographic Information System (“GIS”), creating a single system of record for gas leak data, and providing a spatial display of leak data to improve leak management visibility. The gas leak process utilizes two systems to complete work and monitor gas leak compliance: SAP and

Inspection Manager. Gas leak information is manually transferred between SAP and Inspection Manager and vice versa by compliance technicians. An internal audit identified 7,818 leak orders, resulting in a 61% defect rate, with inconsistent information recorded between SAP and Inspection Manager. Lack of quality controls to help ensure accurate leak information across systems may inhibit the Company's ability to effectively monitor gas leaks and could result in leaks not being re-classified or repaired in a timely manner. This has regulatory compliance and safety impacts such as missed compliance dates which may result in fines and increased public safety risk resulting from untimely or missed leak repairs. The project provides value to both the Company and its customers, including: (1) improving productivity and leak location accuracy; (2) enabling near-real time reporting and automated metric reporting on open leak backlog; (3) creating one system of record for all leak assets in GIS; (4) implementing quality improvements for scheduling and routing of leak crews; (5) reducing risk of future audit findings or non-compliance resulting from duplicate open leak orders; (6) optimizing resource allocation for the gas service posting team by eliminating manual posting of leak repairs in GIS; (7) optimizing resource allocation for the gas compliance team by eliminating the posting of leak repairs in Inspection Manager; and (8) streamlining the leak survey workflow to improve the human struggle caused by use of paper maps and manual processes for leak order tracking. The scope of this project includes: (1) design and implementation of an integration between the asset system and the work management system to create, update, and manage leak maintenance, repair, and emergent orders and inspection schedules through the Enterprise Service Bus or similar technology; (2) configuration of new SAP and Service Suite work order completion forms required to support new work processes; (3) updating the business intelligence dataset to support reporting; (4) reconfiguring workflows in Inspection Manager to capture all leak data from GIS; (5) design and implement a solution to replace the use of paper maps in the leak survey process; (6) implementing a workflow to communicate first time and repeated customer contacts for a given leak; (7) implementing an open leak order geospatial map of all open leak orders, utilized across office and field technology; (8) creating a system indicator that flags duplicate leak orders at the same location; and (9) implementing functionality to provide visibility through a listing of all open leak orders within a specified radius. Five alternatives were considered for the project: (1) Implement a Quality Assurance/Quality Control ("QAQC") process to ensure data is consistent between both SAP and Inspection Manager. This alternative was not selected because it requires an increase in labor costs for manual reporting and data checks. In addition, as demonstrated by the audit, manual processes, even manual QAQC processes, are subject to human error, and each error creates safety and noncompliance risk; (2) Implement a Robotic Process Automation to sync data. This solution was explored but is not viable because the business processes are too complex; (3) Implement a new GIS-based compliance solution that can be integrated with SAP. This alternative is too costly, given recent investment in the current Inspection Manager solution;

(4) Defer project implementation. The alternative selected is to implement this project now, rather than later, as a result of recent gas leak red audit findings; and (5) Implement functionality to automate gas leak compliance tasks and track all gas leak activity in the GIS. This alternative was selected because it leverages existing solutions in a new way, optimizing resources and technology investment. The use of Cloud technology was not considered due to the enhanced functionality being added to systems and applications that are already on-premise.

- The **Gas SCADA Software Solution** project requires $3,641,196 in capital and $479,854 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 $1,328,438 in capital and $500,738 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 & 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.

S T A T E O F M I C H I G A N

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the application of	)	
CONSUMERS ENERGY COMPANY	)	
for authority to increase its rates for the	)	Case No. U-21490
distribution of natural gas and for other relief.	)	
	)	

DIRECT TESTIMONY

OF

TODD A. WEHNER

ON BEHALF OF

CONSUMERS ENERGY COMPANY

December 2023

Q. Please state your name and business address.

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

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

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

Q. What are your current responsibilities?

A. I am responsible for planning and raising the financial capital required by the Company including revolving credit facilities, short-term and long-term debt capital, and equity capital. As part of my role, I work with my treasury colleagues to manage corporate liquidity, financing, and treasury operations, and maintain relationships with the banking community, rating agencies, investors, and research analysts. In order to carry out my responsibilities, I interact with commercial banks, investment banks, credit rating agencies, equity and fixed income analysts, and equity and fixed income investors. I also play a key role in the Company's strategic planning process and in developing the Company's financial plan that fulfills its strategic goals.

Q. What is your educational background?

A. I received Bachelor of Science degrees in Electrical Engineering and Mechanical Engineering from Michigan Technological University in 2002. I received a Master of Business Administration degree ("MBA") from the Ross School of Business at the University of Michigan in 2012, where I focused on finance and strategy. Concurrently, I completed a Master of Science degree from the School of Natural Resources at the University of Michigan.

Q. What positions did you hold prior to your present position?

A. I began my career in 2002 as an Acquisitions and Maintenance Officer in the United States Air Force where I worked with intelligence units through 2006. I was an Electrical Test Engineer with Nissan from 2007 to 2009. After completing my MBA in 2012, I joined Barclays Capital in the Investment Banking Division. In this role, I developed financial models to value both public and private companies, executed merger and acquisition transactions, and executed financing transactions for companies across a number of markets including equity, investment grade debt, and high yield debt. I developed cost of capital analyses, rating agency materials, and strategic review materials for management and boards. In 2014, I joined Morgan Stanley within the Investment Banking Division, performing a similar function but focused solely on the power and utilities sector. I joined Consumers Energy in early 2016.

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

A. Yes. I have provided cost of equity testimony in Case Nos. U-21389, U-21308, U-21224, U-21148, U-20963, and U-20697, as well as testimony focused on other aspects in Case Nos. U-20889, U-20165, and U-18250.

<u>PURPOSE</u>

Q. What is the purpose of your direct testimony?

A. The purpose of my direct testimony is to present my recommendation regarding the Return on Equity (“ROE”) which should be used in computing the overall rate of return for Consumers Energy’s gas business.

Q. Are you sponsoring any exhibits?

A. Yes. I am sponsoring:

Exhibit A-14 (TAW-1)	Schedule D-5	Cost of Common Shareholders' Equity;
Exhibit A-121 (TAW-2)		Wolfe Research: "The Fleishman Daily 11/21/22";
Exhibit A-122 (TAW-3)		Wells Fargo Equity Research: "DTE: Challenging Electric Rate Order – Bears Monitoring";
Exhibit A-123 (TAW-4)		UBS Equity Research: "DTE Energy Co: Electric Rate Case Revenue Light";
Exhibit A-124 (TAW-5)		Moody's Investor Service November 10, 2022 Report;
Exhibit A-125 (TAW-6)		Fama and French: "The CAPM is Wanted, Dead or Alive";
Exhibit A-126 (TAW-7)		Financial Times: "The time has come for the CAPM to RIP";
Exhibit A-127 (TAW-8)		Chartoff, Mayo, and Smith: "The Case Against the Use of the Capital Asset Pricing Model in Public Utility Ratemaking";
Exhibit A-128 (TAW-9)		Chretien and Coggins: "Cost of Equity for Energy Utilities: Beyond the CAPM";
Exhibit A-129 (TAW-10)		*Federal Reserve Bank of New York Staff Reports*: "The Equity Risk Premium: A Review of Models";
Exhibit A-130 (TAW-11)		Brattle Group: "Estimating the Cost of Equity for Regulated Companies";
Exhibit A-131 (TAW-12)		Value Line: "Using Beta"; and
Exhibit A-132 (TAW-13)		Gordon and Shapiro: "Capital Equipment Analysis".

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

A. Exhibit A-14 (TAW-1), Schedule D-5, was prepared under my direction and supervision. The remaining exhibits were gathered from numerous sources commonly relied upon by finance professionals in the course of their work.

I. SUMMARY OF ROE RECOMMENDATIONS

Q. What ROE is the Company recommending for Consumers Energy's gas business?

A. Based on the qualitative and quantitative analyses performed by the Company, a reasonable ROE range for Consumers Energy's gas business is 10.0% to 11.0%. Considering the appropriate balance between the needs of the Company and its customers, the Company recommends the Commission approve an ROE of 10.25% at this time.

The recommended ROE is supported by the consideration of numerous factors including: (i) the current state of the global and U.S. economy and capital markets; (ii) the need to continue to attract capital and maintain financial strength as the Company undertakes a large capital investments designed to improve safety, reliability, and deliver customer value; (iii) the risk profile of Consumers Energy's gas business compared to the proxy group; (iv) established principles for setting a fair ROE, including ensuring the financial soundness and credit of the utility; and (v) results of various economic models used to calculate the cost of equity, all of which are described in detail in Section II.

Q. Discuss why the Commission should increase the ROE.

A. The 10.25% ROE requested by the Company will support the financial and credit needs of the Company while balancing the needs of customers.

Q. What if the Commission considers an ROE below 10.25%?

A. If the Commission considers an ROE below 10.25%, careful consideration should be given to the interplay between the Company's ROE and equity ratio. ROEs and equity ratios are linked and must be viewed together to adequately balance credit supportive financial metrics. As discussed by Company witness Marc R. Bleckman in his direct testimony, the 51.5% equity ratio being recommended by the Company in this case is well below the average equity ratio for the Company's peers. Thus, if the Commission considers an ROE of, for example, 10.0%, the Company would propose an equity ratio of 53.0% in order to be adequately compensated for the tradeoff in lower ROE to maintain credit quality. Further, if the Commission considers maintaining an authorized ROE of 9.9%, which the quantitative and qualitative analyses demonstrate to be below a reasonable range, the Company would recommend and request approval of an equity ratio of 53.5% to maintain credit supportive financial metrics.

This direct testimony and supporting analysis, along with that of Company witness Bleckman, provides justification for the 10.25% or higher ROE recommendation; however, in the event the Commission believes that a more modest increase in ROE is reasonable, such an outcome could be partially mitigated with a corresponding increase in the authorized equity ratio.

II. DEVELOPMENT OF ROE RECOMMENDATION

A. Importance of ROE and Financial Strength

Q. Discuss the importance of financial strength for a utility, including Consumers Energy.

A. A strong, financially healthy utility is critical for providing this essential service to all of the Company's customers. As a regulated utility, Consumers Energy is obligated to serve all customers in its service territory. Doing so requires significant capital for both planned and unplanned investments in property, plant, and equipment. Customers and the state of Michigan are not well served if the Company's ability to meet these obligations is either subject to uncertainty or contingent on the instant state of the capital markets.

Q. Why is reliance on temporary markets a concern when evaluating the financial strength of a utility such as Consumers Energy?

A. As a general rule, the Company, in planning its requested ROE in a rate case, cannot rely entirely on current or temporary market conditions, and, instead, it has to plan for the possibility of unforeseen market events that may impact the Company's borrowing and other operations. Recent global market disruptions such as the Israel-Hamas war, the U.S. banking crisis, the ongoing Russian-Ukraine conflict and COVID-19 pandemic are demonstrative of unforeseen events that can meaningfully impact economic volatility. The Company must prepare for unforeseen events such as these because when markets are volatile there is often a higher cost of borrowing for a utility. This, in turn, means higher costs for making capital investments in property, plant, and equipment, thereby limiting remaining available funds for necessary projects, or both.

Q. What is the practical effect of avoiding this type of volatility in the market?

A. In planning for unforeseen events that may affect market conditions, the Company is taking steps to assure that it remains financially strong in the face of those events as they arise. A financially strong utility that is not reliant upon temporary market conditions has a higher likelihood of maintaining access to capital at reasonable terms throughout the spectrum of possible capital market conditions. Customers would not be well served if the Company were to manage to the margins, as doing so would make the Company particularly susceptible to impacts from market conditions, including those that are unforeseen. Such impacts would cause adjustments or delays in planned work on major infrastructure projects that are geared toward maintaining or improving customer service and secure and reliable energy supply at affordable rates.

Q. What other benefits arise from a reasonable ROE?

A. Authorizing reasonable ROEs are also important because they, in part, contribute to delivering consistent financial performance. Consistent financial performance is attractive to investors and prompts new or continued investment in the Company. The investment provided by utility shareowners, and the return allowed on that equity, provide the financial resources and capital to (i) support the debt financing raised by the utility, (ii) procure contracts with suppliers, and (iii) fund unplanned or unexpected expenses. Thus, a reasonable ROE not only contributes to better credit ratings, it also attracts increased investment interest in the Company, thereby lowering borrowing costs.

Q. Does the Company's ROE recommendation place an undue burden on ratepayers?

A. No. The Company continuously recognizes the need to balance customer and investor interests. Thus, while it is important for an ROE to attract cost-efficient capital discussed above, it is also important to ensure that the ROE is in the best interest of customers. Importantly, the Company's ROE is not the primary driver of customer bills. The recommended ROE of 10.25% would have a minimal gross impact on the average monthly residential customer bill. Impact on a "gross" basis is emphasized because this ROE impact may be partially offset by lower debt costs and improved access to capital markets.

B. <u>General Principles</u>

Q. What are the general principles in setting a fair rate of return and return on common equity?

A. For regulated companies, the landmark United States Supreme Court cases In *Federal Power Commission v Hope Natural Gas Company*, 320 US 591 (1944), and *Bluefield Water Works and Improvement Company v Public Service Commission of West Virginia*, 262 US 679 (1923) have established the framework upon which a company's fair rate of return may be determined. The Company uses the principles set forth in those cases in determining the ROE requested in this case.

Q. How are ROE and rate of return related?

A. ROE is a measure of how much return a company is able to generate with each dollar of shareholder equity (investment) it receives. Investors compare the ROE of similar companies to help them decide which ones constitute the most attractive investment choices. ROE is a significant part of a company's overall rate of return, which is the amount of return a utility earns, over and above its expenses.

Q. To support the principles reflected in *Hope* and *Bluefield,* what methodology was employed by the Company for setting a fair ROE?

A. Several quantitative models were employed to determine an appropriate return for investments having commensurate risk. Additionally, an analysis of the ROE and equity ratio that would support the Company's long-term Funds from Operations ("FFO") to Debt and credit was also performed and is more fully discussed in the testimony of Company witness Bleckman.

Q. Why were multiple methodologies employed to determine a recommended ROE?

A. ROE is an imprecise calculation. As a result, multiple methodologies were utilized because: (i) each of these methods, individually, will often produce a range of values that should be considered in relation to each other, as illustrated by Exhibit A-14 (TAW-1), Schedule D-5, page 11; and (ii) the results of these quantitative models can often make assumptions that do not necessarily fully reflect the returns that investors require, given current economic and financial conditions. As such, the application of multiple methods as well as an understanding of model assumptions, in combination with an overall qualitative assessment of the marketplace, provides a more comprehensive evaluation of cost of capital and is most appropriate in evaluating the required cost rate for common equity capital.

C. Summary of ROE Results

Q. Can you summarize the results of Consumers Energy's cost of common equity analyses?

A. The results of the analyses are summarized and graphically represented in the table and chart below.

Summary of ROE Estimates

Capital Asset Pricing Model ("CAPM")	12.58% - 13.61%
Empirical Capital Asset Pricing Model ("ECAPM")	12.88% - 15.37%
Projected Risk Premium	10.24% - 11.18%
Analyst Consensus Discounted Cash Flow ("DCF")	6.92% - 13.12%
Comparable Earnings	8.18% - 14.05%
Recommended Range	**10.0% - 11.0%**

Q. How did the Company determine that a 10.25% ROE is appropriate based on this range?

A. Based on analyses and consideration of the factors discussed below, an appropriate ROE range for Consumers Energy's gas business for the test year is 10.0% to 11.0%. The significant need to update the Company's and the state's energy infrastructure would suggest an ROE in the upper half of the recommended range. The recommended ROE of 10.25%, while above the current authorized ROE, is below the center of the reasonable ROE range and represents a reasonable ROE for the Company given the Commissions preference for gradualism. As stated above, if a lower than recommended ROE is authorized in this case, careful consideration should be given to an increase in the equity ratio as recommended by Mr. Bleckman to help balance the Company's credit metrics and maintain its credit health.

D. Qualitative Equity Cost Rate Considerations

1. Investor and Rating Agency Expectations and View of Regulatory Environment

Q. How do investors view the current regulatory environment in Michigan?

A. Investors have generally historically viewed the regulatory environment in Michigan as supportive; however, this perspective is continually subject to change since their interests and expectations are predicated on expected future outcomes. If the investor view of the Michigan regulatory environment becomes less certain or less predictable, then they will be less inclined to invest further capital into Michigan utilities, which would lead to higher funding costs and would be detrimental to customers.

Q. Do investors and rating agencies make assumptions regarding the ROE for Consumers Energy?

A. Yes. The ROE authorized by the Commission and the ability of Consumers Energy to earn the authorized return are important factors considered by investors and rating agencies. In fact, a utility's authorized ROE and a consistent, constructive track record in this regard are key components in credit ratings assessments.

Q. Do you have examples of these assessments from the Rating Agencies?

A. Yes. The June 23, 2017 *Regulated Electric and Gas Utilities Rating Methodology* for Moody's Investors Service ("Moody's"), for example, includes the following factors:

- Legislative & Judicial Underpinnings;
- Consistency & Predictability; and
- Sufficiency of Rates & Returns.

Similarly, Standard & Poors ("S&P"), in its "Key Credit Factors For The Regulated Utilities Industry," reports the importance of earning a timely return:

> We base our assessment of the regulatory framework's relative credit supportiveness on our view of how regulatory stability, efficiency of tariff setting procedures, financial stability, and regulatory independence protect a utility's credit quality and its ability to <u>recover its costs and earn a timely return.</u> [S&P, November 19, 2013. (Emphasis added.)]

In fact, S&P calls the ability to earn a timely return one of its "four pillars" in the "foundation of a utility's regulatory support."[1] These credit rating assessments provide confirmation that the authorized ROE and rates sufficient to earn the authorized ROE in this case are important signals that the Commission sends to the investment community.

Q. Do you have examples of these assessments from the investment community?

A. As part of my role within the Company, I have had many conversations with investors and rating agencies. They recognize the historical strength of Michigan's regulatory construct and legislative framework, but while they still believe Michigan to be a fairly strong regulatory environment, several have expressed concerns regarding authorized ROEs and a perceived deterioration in Michigan's regulatory environment in recent years from the premium spot it once held. After the Commission's Order was issued in DTE Electric's recent Electric Rate Case (Case No. U-20836), The Fleishman Daily from Wolfe Research observed the following:

> The revenue requirement and rate base portion of the order looks very light, as it was well below what Staff/ALJ had even recommended, which is disappointing . . . . This reminds us of CMS' electric rate order a year ago, which had an equally tepid rate hike . . . . Michigan has a history of constructive regulation, but this is now 2 disappointing orders in the last 12 months, which is a little bothersome… [Exhibit A-164 (TAW-2), page 3, Wolfe Research, November 21, 2022.]

---

[1] S&P report, "Key Credit Factors For The Regulated Utilities Industry," November 19, 2013. See page 6.

Wolfe Research is a research firm which closely monitors the industry and reports on associated topics and how they impact their perceived corporate risk and return market positions. Investors subscribe to the Wolfe Research platform in order to gain access to their opinions and content produced. Mr. Fleishman is one of the most experienced, knowledgeable, and respected utility sector analysts, but he is not alone in his sentiment on ROE and risk in the state.

> Simply put, the MPSC's order was unexpected . . . we are troubled by the outcome in the electric rate case. . . . It marks the second consecutive electric rate order in MI that has proved challenging . . . . In our view, the last two electric rate cases in MI raise the concern that the MPSC is more aggressively hunting for ways to lower customer bills, as opposed to the perceived balanced approach that defined the Commission's regulatory outcomes over the last decade. [Exhibit A-122 (TAW-3), page 1, Wells Fargo Research, November 21, 2022.]

> The [order approved rate] increase is below the ALJ's recommended increase of $146 million. The rate base was in line with the ALJ's decision and 4% below the UBS estimate… [Exhibit A-123 (TAW-4), page 1, UBS Research, November 18, 2022.]

The UBS report specifically states their view that investors have responded to the DTE order somewhat negatively, and the three analyst comments above should make it very clear that investors watch in-state peers for read throughs in the state's regulatory environment as to whether or not investments earn a compensatory return for associated risks.

Q. How will investors view the Company's proposed ROE?

A. Investors are likely to consider an authorized ROE of 10.25% together with an equity ratio of 51.5%, and other regulatory adjustments proposed by the Company, to be commensurate with the risks involved in investing in Consumers Energy.

Q. Have the rating agencies commented on the Company's credit?

A. Yes. In May 2021 Moody's downgraded the Company's credit rating while pointing to recent rate case outcomes and their negative impact on weakened credit metrics. See Exhibit A-34 (MRB-12), page 1; see also Exhibit A-124 (TAW-5).

S&P's summary of the final Order in Case No. U-20697 stated the following:

> Although we view resolving the effects of tax reform through this rate case as favorable, if lower ROEs and a lower equity ratio persist, credit quality could weaken. [Exhibit A-36 (MRB-14), page 3, S&P, January 27, 2021.]

Further, they went on to state their view that the lower equity ratio and ROE in the case are not supportive of credit quality. See Exhibit A-36 (MRB-14), page 4.

Q. Does S&P continue to hold a negative outlook on the regulated utility sector?

A. In January 2023, S&P published a report which reiterated that "the industry's outlook remains negative" as well as their concern with weakening financial measures and credit pressures. This report was provided by Company witness Bleckman, Exhibit A-35 (MRB-13).

Q. Discuss the relationship between the Company's ROE, its equity ratio, and the Company's credit metrics.

A. A key metric that is used to identify the credit worthiness of a company, including Consumers Energy, is the ratio of FFO-to-Debt. An FFO-to-Debt ratio is a financial metric that compares a company's cash flow from operating activities to a company's leverage, or debt outstanding. A higher FFO-to-Debt ratio, which reflects a cash flow from operating activities that is at a level viewed as favorable to offset or otherwise reduce the risk associated with the Company's ability to pay its debts, is indicative of a lower financial risk and a resulting higher credit rating. A higher credit rating, in turn, results in lower financing rates. The two biggest factors that determine this ratio are the Company's ROE and equity ratio.

Q. Please summarize the Company's conclusions regarding investor and credit rating agency expectations.

A. Based on direct interactions with investors and the rating agencies as well as their printed publications, it is clear that they view the authorized ROE as a critical metric which serves as the key barometer of the regulatory environment in Michigan. As such, a reduction to the authorized ROE will negatively affect their perception of the credit quality of Consumers Energy and, thus, reduce investor willingness to invest in Consumers Energy and, ultimately, in Michigan. While investors have in the past held a view of Michigan's regulatory environment as fairly constructive, their assumptions are based on return stability in regulatory outcomes. If investors and the credit rating agencies continue to perceive the regulatory environment as further deteriorating, it would quickly undercut the view that was previously supported.

2. <u>Interest Rates</u>

Q. What role do interest rates play in cost of capital determinations?

A. Interest rates clearly play an integral role in cost of debt determinations and, because debt composes a large portion of a utility's capital structure, interest rates also play a large role in determining a utility's overall cost of capital. Both short-term and long-term interest rates influence cost of capital, but the impact can vary depending on a company's capital structure. This is most clearly evidenced by Mr. Bleckman's Exhibit A-14 (MRB-1), Schedule D-1, which outlines the Company's overall rate of return and highlights the Company's capital structure both on a permanent capital and total capital basis. As seen in the exhibit, long-term interest rates are considered in the permanent capital structure as the cost rate of the long-term debt of the Company. Because most of the Company's outstanding long-term debt is of a fixed interest rate structure, long-term interest rates affect the planned financings of the Company. Short-term interest rates also affect a company's expenses but do not get considered in the permanent capital structure of the Company. The effects of long-term and short-term interest rates are differentiated, but both impact the Company's cost of equity analysis as will be discussed below.

Q. How are short-term interest rates anticipated to move going forward?

A. The Federal Reserve has increased short-term rates dramatically, in an unprecedented fashion beginning in 2022 in an attempt to catch up with inflationary pressures in the market. The phrase used by analysts, which has become a drumbeat, is "higher for longer." This refers to expected rate levels to remain at elevated levels for much longer than previously predicted. Over time, the Federal Reserve will also need to continue to look for ways to bring down the size of its balance sheet to more normal levels, which will maintain additional upward pressure on interest rates.

Q. What is the Company's assessment of current long-term interest rates?

A. Long-term interest rates had been held artificially low by the Federal Reserve as a response to anemic domestic and global economic growth for a decade. The changes to the short-term interest rates along with other Federal Reserve policies have drastically moved the long-term interest rates to a much higher level than just eighteen months ago. While the interest rates are no longer at such drastically artificially low levels, what has not changed is the dramatically high amount of Federal Reserve action and the institution's influence and impact on the interest rate yields observed in the marketplace.

Q. How do the actions by the Federal Reserve to influence long-term rates impact the cost of capital analysis for utilities?

A. One of the key components in many of the quantitative models is the interest rate on long-term government bonds as a benchmark; however, in an environment where the Federal Reserve is moving interest rates so much in such a short period of time, these unadjusted models can become less reliable. While unadjusted models could indicate diminished expected investor returns, investors' expectations for equity returns do not decrease as a result of the increased risk and market volatility that the Fed's actions have driven – in actuality, the very opposite is true.

Q. Do interest rate expectations utilized in the analysis fully reflect the conditions in the test year?

A. No. Near-term expectations usually have some relative consensus; however, given the continued uncertainty regarding the economy, inflation, ongoing global conflicts, and geopolitical actions, near-term expectations have larger-than-normal variation, and future periods demonstrate considerable variability as to expected yields. Further, utility stocks are highly sensitive to interest rates, so as interest rates rise, utility stocks are often the most negatively impacted and, therefore, the utility cost of equity increases in turn.

Q. How were limitations of mechanical application of quantitative models considered in the Company's ROE analysis?

A. The quantitative models typically utilized to determine required ROE rely on either static conditions or use of historical data as benchmarks that do not correctly reflect today's current market conditions or the expected market conditions in the future test year. The limitations of various models were addressed in part by employing multiple methodologies, using projections for market inputs (risk-free rates, dividends, and risk premiums), and using independent judgment based on conversations with, and feedback from, the investment community.

3. ROE Trends

Q. Is there a single comprehensive source of authorized ROEs around the country?

A. No. There is no accurate or complete source for national ROEs.

Q. Do you consider the *S&P Global Regulatory Research Associates* ("RRA") database a complete source for national ROE trends?

A. No. While the RRA database has increased data in an attempt to become a complete and comprehensive resource, it still remains incomplete.

Q. Is the national average ROE that RRA publishes a complete metric that can be relied upon by commissions?

A. No. While the RRA database reflects a growing number of ROE metrics, the national average ROE metric that it publishes, and that intervenors have referenced in the past, is not complete and should not be relied upon.

4. Economic Outlook and Uncertainty

Q. Was the current state of the economy considered in performing the Company's ROE analysis?

A. Yes, both national and global factors were considered. Several of the analyses require market observations that are impacted by the current state of the United States economy. In addition, global economic factors play into investor considerations because of the ripple effects on the United States economy and the integrated nature of global financial markets.

Q. How would you assess the uncertainty in the market, and how does uncertainty impact risk?

A. There are several ways to estimate the current level of market uncertainty. Levels of uncertainty were considered high pre-COVID pandemic and rose dramatically post-pandemic. Market uncertainty has remained quite high due to past and ongoing crises mentioned earlier. In addition to the aforementioned, the United States government has increased market uncertainty, experiencing credit rating downgrades, government shutdowns that have been narrowly and temporarily averted, multiple attempts to elect a Speaker of the House of Representatives, all of which has taken place in 2023. While some of these drivers may pass, they will likely be supplanted by others. The upcoming elections in 2024 will bring about additional market uncertainty, and many will persist throughout the test year. Increased uncertainty is a clear sign of increased market risk, which in turn increases the required returns by investors.

Q. Why is it important to consider the economy in performing an ROE analysis?

A. The Company makes long-term investments in infrastructure to serve customers, but market uncertainty affects risk to investors. The competition for capital investment to fund projects has continued to increase, and all of these factors have increased uncertainty and utility investor risk in the market and, thus, impact an analysis of ROE.

5. Capital Investment

Q. Does the Company's significant capital investment impact the appropriate ROE determined in this case?

A. Yes. Consumers Energy plans to continue making significant needed capital investments in Michigan to provide safe and reliable service to customers, in compliance with federal and state requirements. The Company's five-year plan includes investment of approximately $15.5 billion on a total company basis, $6.3 billion of which is earmarked for gas infrastructure investment.[1] This level of capital investment increases the risk profile of the Company for investors and the rating agencies. Authorizing an ROE in this case at a level that investors view as adequate to compensate them for the risk is necessary to attract large amounts of cost-effective capital to Michigan to keep Consumers Energy financially healthy to the benefit of customers. Authorizing an ROE that investors consider to be below expectations could lead to increases in cost of capital or hinder the Company's ability to access capital altogether, neither of which is in the best interest of customers.

Q. Please discuss the role of ROE in attracting capital.

A. One of the key principles in setting an ROE is to maintain the financial integrity of the utility so that it maintains its credit. Equally important is setting an ROE that attracts capital. The State of Michigan has ambitious goals to improve the energy infrastructure which will require significant capital. While undertaking any major projects increases the risk profile of a company, public utilities are a primary vehicle to fund and execute these infrastructure investments. However, utility management teams cannot simply invest capital without evaluating its impact on investors as they owe a fiduciary obligation to their shareowners and must be cautious when investing capital in a business where the ROE, relative to other projects, is less attractive. Michigan must compete for investment dollars with all the state jurisdictions highlighted earlier which provide ROEs that are significantly more attractive than the Company's current 9.9%. Further, if investors and management teams perceive the risk that invested capital would be subject to further downward pressure

[1] See Consumers Energy 2022 10-K report, page 57.

in the future, they will be increasingly cautious about current investments in order to avoid this risk. The ROE proposed by the Company in this case would send an important signal to investors that management is not investing in a company or state that has a declining regulatory environment.

E. Quantitative Equity Cost Rate Analyses

1. Selection of Proxy Companies

Q. Why was a group of proxy companies selected to perform the quantitative analyses?

A. Since the common stock of Consumers Energy is not publicly traded, it is necessary to use indirect or proxy approaches to calculate an appropriately representative ROE.

Q. Please describe how a proxy group of companies was chosen.

A. The focus of this case is on Consumers Energy's gas operations; therefore, the primary focus was on publicly traded companies headquartered in, and with operations in the United States, and companies of comparable credit rating and size.

Q. Please explain.

A. In order to be included in the proxy group:

(i) The companies had to be headquartered in and have the vast majority of operations within the United States;

(ii) The companies were required to have a market capitalization greater than $1 billion and less than $30 billion. This filter focuses on comparably-sized companies in the relative range of Consumers Energy's natural gas business. Academic literature has shown a correlation between company size and ROE, making this an important criterion to include.[1]

[1] See Fama, French, K. R. (1992) – *The Cross-Section of Expected Stock Returns* at https://www.ivey.uwo.ca/media/3775518/the_cross-section_of_expected_stock_returns.pdf

(iii) The companies were required to have a dividend payout ratio in the last 12 months greater than or equal to 45%;

(iv) The companies were required to have significant gas utility operations;

(v) The companies could not be a recent merger targets or be recently or currently engaged in significant restructuring, as this type of activity can materially distort a company's data to the extent it should not be credibly included in a proxy group; and

(vi) The companies' bonds must be rated at or above a minimum investment grade of Baa3 by Moody's and BBB- by S&P.

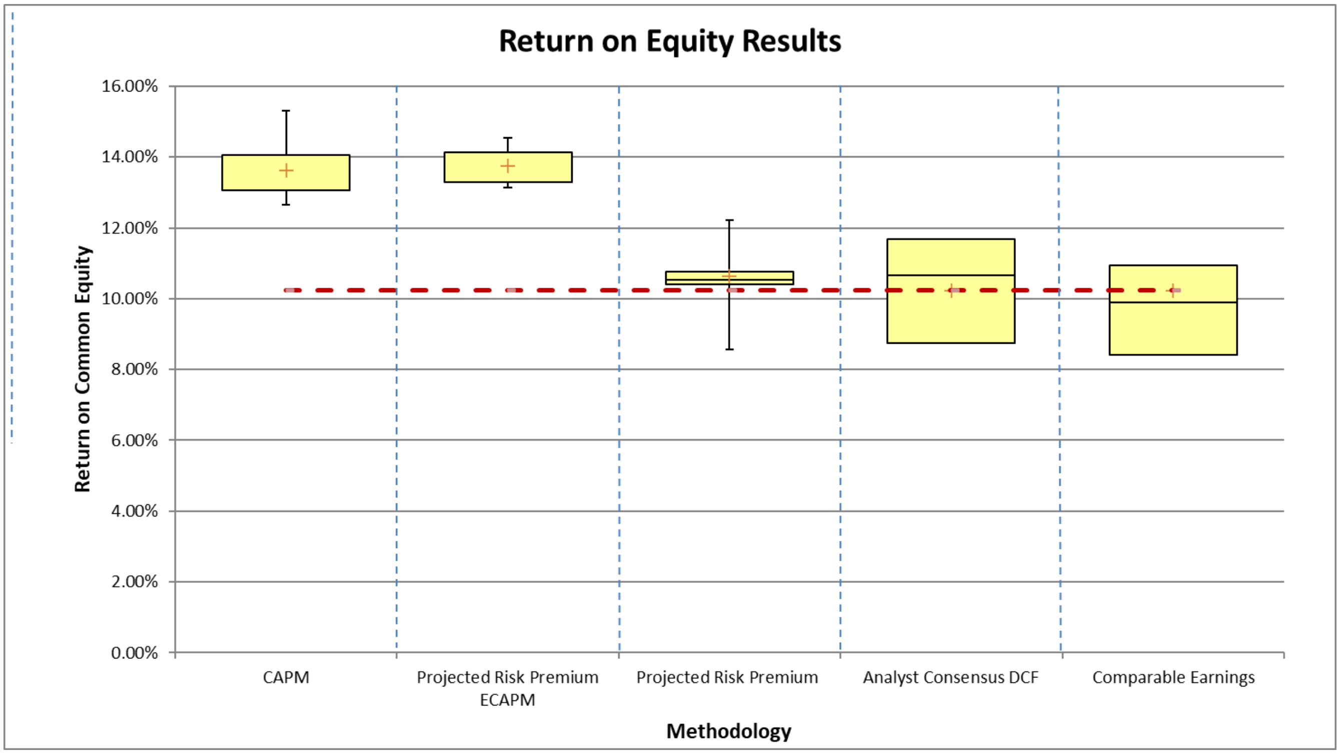
Q. How does the resulting proxy group differ from the most recent gas rate case?

A. The application of these criteria resulted in a proxy group of nine companies, the same Company proxy group from Case No. U-21308. The list of the proxy group companies, the selection criteria, and the data supporting inclusion is set forth on Exhibit A-14 (TAW-1), Schedule D-5, page 1.

2. Methodologies Utilized to Determine Proposed ROE

Q. As discussed above, multiple methodologies were utilized to arrive at a proposed ROE in this matter. What methodologies did you employ?

A. I utilized the CAPM, ECAPM, Projected Risk Premium, Discounted Cash Flow ("DCF"), and Comparable Earnings Analysis. As discussed below, the estimated ROEs for each methodology utilized by the Company were as follows:



Q. How are these methodologies and results utilized to determine an appropriate ROE for the Company?

A. The application of multiple methods, combined with an overall qualitative assessment of the marketplace, provides a more comprehensive evaluation of cost of capital and is most appropriate in evaluating the required cost rate for common equity capital.

a. <u>CAPM Analyses</u>

Q. What is the basic theory behind CAPM and ECAPM?

A. The principal assumption of the CAPM and ECAPM is that the expected return on an asset is related to risk – that is, risk taking by investors is rewarded with appropriate returns. The CAPM and ECAPM are based on the premise that an investor's expected rate of return on an investment is equal to a risk-free rate of return plus a risk premium as a form of additional compensation for investors' additional risk tolerance. The size of the risk premium for an investment is dependent on the amount of unavoidable (or systematic) risk taken. An investment's systematic risk is obtained by the application of a beta, which is a measure of the risk arising from exposure to general market movement and is used as an indication of the risk of an investment relative to the risk of a market portfolio consisting of all types of risk-oriented assets.

Q. Please explain the application of beta to determine risk premium.

A. Under the theory of CAPM, beta is a measure of the systematic risk of a security as compared to the systematic risk of the market as a whole. Beta is a coefficient resulting from a regression of the return of a single stock to the return of the market. The beta for the market is always equal to 1.00. Companies whose securities have betas greater than 1.00, therefore, are generally considered riskier than the market as a whole, while companies with betas less than 1.00 are generally considered less risky than the market as a whole. CAPM is based on the concept that investors demand higher returns for assuming additional risk and, accordingly, higher risk securities are priced to yield higher returns than lower risk securities. Under CAPM theory, there is an incremental premium for bearing additional risk, as measured by beta, above the risk-free rate, which is traditionally seen as the income return available from investing in United States Government Treasury securities (bonds). The model assumes that prices for individual securities are determined in efficient markets where information is freely available and instantaneously reflected in security prices. The specific CAPM formula is expressed as:

Equation (5): $K_e = R_f + F + B \times (R_p)$

Where:

K_e = annual required cost of equity;
R_f = risk-free rate;
F = flotation cost adjustment;

β = beta; and
Rp = risk premium which reflects the market return less the risk-free rate.

Q. Do CAPM results capture all the risk faced by utility investors?

A. No. The CAPM has a number of shortcomings which are particularly relevant to public utilities and are well documented in academic literature:

- Fama and French: "The CAPM is Wanted, Dead or Alive," (Exhibit A-125 (TAW-6));
- Tony Tassell: "The time has come for the CAPM to RIP," *Financial Times,* (Exhibit A-126 (TAW-7));
- Chartoff, Mayo, and Smith: "The Case Against the Use of the Capital Asset Pricing Model in Public Utility Ratemaking," (Exhibit A-127 (TAW-8));
- Chretien and Coggins: "Cost of Equity for Energy Utilities: Beyond the CAPM," (Exhibit A-128 (TAW-9)); and
- Robert Morin: *New Regulatory Finance.*

Q. Please summarize the shortcomings.

A. First, studies have shown that the CAPM tends to overstate the sensitivity of the cost of capital to beta. Low beta assets tend to have higher average returns than would be predicted, while high beta assets have lower returns. The beta of utilities, including the Company's proxy group, as shown on Exhibit A-14 (TAW-1), Schedule D-5, page 2, are typically less than 1.00 and would, therefore, tend to have higher average returns than predicted by the model. Second, CAPM relies on beta to capture all the systematic risk faced by a company and assumes that the only unavoidable (or systematic) risks are fluctuations in the market. Market beta calculates a low result for a company with a low correlation to the broad market when, in fact, the company could experience high stock volatility that is simply not correlated with the market. Utilities are interest rate sensitive and exposed to regulatory risk, neither of which market force is captured by the traditional CAPM analysis.

Q. How did the Company address the customary CAPM model shortcomings referenced above?

A. In order to partially adjust for the shortcomings of the CAPM model, the Company applied projections for the risk-free rate and the risk premium for the test year in this case. The Company also performed the ECAPM analysis to further address the estimate shortcomings.

Q. What are the results of applying the CAPM on the group of proxy companies?

A. The CAPM results are found on Exhibit A-14 (TAW-1), Schedule D-5, page 2. The CAPM ROEs are displayed in column (g) and show the average ROE for the proxy group is 13.619% and range from a minimum of 12.58% to a maximum of 15.52%.

Q. Please describe the ECAPM approach.

A. The ECAPM begins with the same assumptions as the CAPM. To better predict the relationship between asset returns and risk, the ECAPM includes an "alpha" adjustment to the risk-return line. The specific formula of ECAPM is expressed as:

Equation (5a): $K_e = R_f + \alpha + F + B \text{ x } (R_p - \alpha)$

Where:

K_e = annual required cost of equity;
R_f = risk-free rate;
α = alpha;
F = flotation cost adjustment;
β = beta; and
Rp = risk premium which reflects the market return less the risk-free rate.

Q. What is alpha in this ECAPM approach?

A. The alpha adjustment in the ECAPM approach is simply an adjustment made to the CAPM formula to more closely align the expected returns with market observed results.

Q. What values were assumed for the components of this analysis?

A. Except for alpha, which is not a component of the CAPM formula, the same values as the CAPM were used. For alpha, 1.5% was applied, which is the mid-point in the range of 1% to 2% described as reasonable by Dr. Morin in his book *New Regulatory Finance*.

Q. Does the application of long-term risk-free rates and adjusted betas fully address the concerns that ECAPM is meant to reconcile?

A. No. Application of a long-term risk-free rate and adjusted betas addresses some of the CAPM shortcomings, but it does not fully address the shortcomings of CAPM. Alpha adjustment is still necessary to address the key differences between CAPM and ECAPM. In fact, without the use of adjusted beta and long-term risk-free rates, the alpha adjustment would need to be higher than the proposed 1.5%.

Q. What are the results of applying the ECAPM on the group of proxy companies?

A. The ECAPM results are found on Exhibit A-14 (TAW-1), Schedule D-5, page 3. The ECAPM ROEs are displayed in column (h) and show the average ROE for the proxy group is 13.76% and range from a minimum of 12.88% to a maximum of 15.37%.

Q. What is the source of your market risk premium for the CAPM and ECAPM methodologies?

A. In order to estimate an appropriate projected risk premium for the projected test year, I calculated a market implied equity risk premium of the S&P 500 that is developed in Exhibit A-14 (TAW-1), Schedule D-5, page 10. A projected, or forward-looking, market risk premium was estimated based on the expected market return of the S&P 500 Index and the expected yield of the 30-year United States Treasuries during the projected test year was subtracted from it. The expected market return was calculated as the summation of the dividend yield and the long-term Earnings Per Share ("EPS") growth estimates for the entire index. The estimated market capitalization weighted dividend yield of 1.74% and long-term EPS growth estimate of 12.80% resulted in a sum expected market return of 14.54% as of October 5, 2023. Subtracting the expected 30-year United States Treasury yield of 4.73% for the test period results in an estimated market risk premium of 9.81% for the test period.

Q. Is there support for a forward-looking market risk premium such as this?

A. Yes. Because the test year is in the future, it makes sense that the analyses supporting Company recommendations rely on projected market data to estimate returns for the forward-looking period; therefore, projected inputs and assumptions are appropriate.

Q. As demonstrated and discussed above, a risk-free rate was applied to the CAPM analyses in order to partially adjust for the shortcomings of the CAPM model. How were the projected risk-free rates attained?

A. The test year risk-free rate was calculated by utilizing the estimate provided by Bloomberg's Forward Curve derived estimate. In the past, the Company has relied on *Blue Chip* and *IHS Markit* for 30-year United States Treasury Bond yield estimates. These publications (*Blue Chip* and *IHS Markit*) are released quarterly, but they rely on the most recent estimates provided by individual source estimates. As such, an estimate could have been revised a day, weeks, or months prior to the quarterly publications. That may be acceptable in stable rate markets, but given the rapid move in rates in the past 18 months, the stale estimates led to meaningful discrepancies between *Blue Chip* and *IHS Markit* estimates and current rates, sometimes as soon as they were released. Those estimation errors could be magnified into the projected test year. Instead, the Company has relied upon Bloomberg data, as the implied forward yield curve captures real-time changes in market sentiment with regard to interest rate expectations. The average yield on 30-year United States Treasury Bonds for the test year are projected to be 4.73%.

Q. Why were longer dated bonds chosen?

A. The time horizon of the chosen Treasury security should match the time horizon of whatever is being valued. When valuing a business that is being treated as a going concern, the yield of a long-term Treasury bond is appropriate.

Q. What beta was used for purposes of the Company's ECAPM analysis?

A. The values of beta calculated by Value Line were used. Value Line computes historical betas using data over the last five years and adjusts this historical beta using the method prescribed by the great academic Marshall E. Blume to make it an expected beta. The resulting betas are used in CAPM and ECAPM analyses, and the values of beta for the Company's proxy group of companies are found on Exhibit A-14 (TAW-1), Schedule D-5, page 2. The average current beta for the Company's proxy group is 0.91.

Q. Does the ECAPM address all the shortcomings of CAPM?

A. No. ECAPM is focused on the understatement of ROE for low beta stocks and does not necessarily capture all the systematic risk associated with a stock that would require an upward adjustment to fully address.

Q. Is there third-party support for the use of ECAPM?

A. Yes. As discussed earlier in this direct testimony, the CAPM has several deficiencies which impact utilities in particular. There are numerous academic articles that have discussed the shortcomings of CAPM. The simple adjustments formulated by Dr. Morin to correct these deficiencies were used. Dr. Morin's detailed analysis of the ECAPM can be found in chapter 13, page 189, of his 1994 book, *Regulatory Finance*, and chapter 6 of his latest book, *The New Regulatory Finance*, both published by Public Utilities Report Inc. In addition, findings from a February 2013 report from the Brattle Group entitled "Estimating the Cost of Equity for Regulated Companies" (Exhibit A-130 (TAW-11), pages 15-20) reinforce the many weaknesses in the CAPM model as well as the suitable application of the ECAPM to correct for these deficiencies.

Furthermore, an academic research paper focused specifically on utility companies in North America titled "Cost of Equity for Energy Utilities: Beyond the CAPM" (Exhibit A-128 (TAW-9)) concluded the following:

> We find that the CAPM significantly underestimates the risk premium for energy utilities compared to its historical value by an annualized average of more than 4%.

The study looked at CAPM extensions to remove the underestimation error, one of which is an adjusted CAPM similar to the ECAPM in the Company's analysis. The research states that, unlike CAPM, the adjusted CAPM, "[p]rovide(s) econometric estimates of the risk premium that do not present a significant misevaluation." This is yet another clear example that the use of ECAPM in the Company's analysis is not only supported and logical, but necessary in setting a fair ROE.

Q. Beyond academic literature, are there examples of applications of the ECAPM analysis as used by the Company?

A. Yes. The ECAPM has been utilized in Alaska, Alberta Canada, Arkansas, Colorado, Maryland, Minnesota, Mississippi, New York, and Wyoming. The ECAPM has been utilized in rate case proceedings and is included among the models relied upon by some regulatory witnesses and decision makers. For example:

(i) Alaska: The Regulatory Commission of Alaska has also relied on the ECAPM approach, noting that:

> Tesoro averaged the results it obtained from CAPM and ECAPM while at the same time providing empirical testimony that the ECAPM results are more accurate then [sic] traditional CAPM results. The reasonable investor would be aware of these empirical results. Therefore, we adjust Tesoro's recommendation to reflect only the ECAPM result;[1]

(ii) Alberta, Canada: The Alberta Utility Commission's decision 20622-D01-2016 in October 2016 determined the ECAPM model could contribute to that commission's established fair allowed ROE. The commission in that jurisdiction noted in its findings, "[t]he use of ECAPM is an approach recognized in the academic literature and is used to address a perceived issue with the CAPM . . . ." While this case did not have enough information to rely heavily on the ECAPM, they did recognize its relevance as well as academic support and stated that it could be used to determine an ROE;

(iii) Arkansas: The Office of Arkansas Attorney General conducted CAPM and ECAPM analysis and stated, "The ECAPM is a version of the CAPM modified to adjust for identified shortcomings in the CAPM;"[2]

(iv) Colorado: The Staff of the Colorado Public Utilities Commission has also recognized that "[t]he ECAPM is an empirical method that attempts to enhance the CAPM analysis by flattening the risk-return relationship,"[3] and relied on the same standard ECAPM equation presented above;

(v) Oklahoma: Office of Oklahoma Attorney General conducted analysis using both CAPM and ECAPM analyses;[4]

(vi) Maryland: The ECAPM approach has been relied on by the staffs of the Maryland Public Service Commission ("Maryland PSC"). For example, staffs witness Julie McKenna in Maryland PSC Case No. 9299 noted that "the ECAPM model adjusts for the tendency of the CAPM model to underestimate returns for low Beta stocks," and concluded, "I believe under current

[1] Regulatory Commission of Alaska, Order No. P-97-004(151) (Nov. 27, 2002), page 146.
[2] Docket No. 17-071-U, direct testimony of Marlon F. Griffing, Ph.D. (May 29, 2018), page 29.
[3] Proceeding No. 13AL-0067G, answer testimony and exhibits of Scott England (July 31, 2013), page 47.
[4] Case No. PUD 201800140, responsive testimony of Marlon F. Griffing, Ph.D, (April 22, 2019), pages 41-43.

economic conditions that the ECAPM gives a more realistic measure of the ROE than the CAPM model does";[1]

(vii) Minnesota: The Minnesota Department of Revenue included ECAPM as one of the methodologies used in determining the value of property in its 2019 Assessment;[2]

(viii) Mississippi: The Mississippi Public Utilities Commission recognizes the ECAPM and has included it in ratemaking.[3] A 2013 study by Christensen Associates commissioned by the Mississippi Public Utilities Commission Staff, called "Discussion of the Return on Equity and Performance Indicators of Entergy Mississippi Inc. and Mississippi Power Company," explicitly acknowledges the Mississippi Power Company's use of Value Line betas in the applied CAPM (Empirical) calculations;

(ix) Montana: the Montana Public Service Commission also recently provided clear, explicit support of ECAPM with their conclusion captured in Order 7575c:

> The evidence in this proceeding has convinced the Commission that Empirical Capital Asset Pricing Model ("ECAPM") should be the primary method for estimating the Joint Applicants' cost of equity in two different variations". dated September 26, 2018[4]
>
> However, the Commission is persuaded by Morin's representation that "[t]he ECAPM and the use of adjusted betas comprise two separate features of asset pricing. Even if a company's beta is estimated accurately, the CAPM still understates the return for low-beta stocks." *See* Morin, Roger A. "Chapter 6: Alternative Asset Pricing Models." New Regulatory Finance Vienna: Public Utilities Reports, Inc. 2006.191. The Commission agrees with Scheig that the issue should be remedied by adopting the ECAPM…[5]

---

[1] Direct testimony and exhibits of Julie McKenna, Maryland PSC Case No. 9299 (October 12, 2012), page 9.
[2] 2019 Capitalization Rate Study, Minnesota Department of Revenue (May 13, 2019).
[3] A March 8, 2013 study by Christensen Associates commissioned by the Mississippi Public Utilities Commission Staff called "Discussion of the Return on Equity and Performance Indicators of Entergy Mississippi Inc. and Mississippi Power Company," explicitly acknowledges shortcomings of CAPM on page v, and provides ECAPM as one method to help address the shortcoming, as defined on page 60. Further, the Mississippi Public Service Commission Schedule No. 28.1 *Performance Evaluation Plan Rate Schedule "PEP-5A"* specifically defines ECAPM on page 24.
[4] Public Service Commission of the State of Montana, Docket No. D2017.9.80, Order No. 7575c, page 40
[5] Public Service Commission of the State of Montana, Docket No. D2017.9.80, Order No. 7575c, page 42.

(x) New York: The New York State Public Service Commission has utilized what they refer to as the zero beta CAPM analysis dating back as early as the 1980s. Zero-beta CAPM is another name for ECAPM, as it references the traditional CAPM model's inability to capture necessary return for a zero-beta stock in excess of the riskless rate. The Commission confirmed their reliance upon the zero-beta model as recently as April 20, 2017 in the final order in Case No. 16-G-0257;[1]

(xi) Wyoming: The Wyoming Office of Consumer Advocate, an independent division of the Wyoming Public Service Commission, has also relied on this same ECAPM formula in estimating the cost of equity for a natural gas utility;[2] and

(xii) Other Agencies: Additionally, Shannon Pratt and Roger Grabowski's book, *Cost of Capital in Regulated Utilities: Applications and Examples*, describes how the Surface Transportation Board significantly revised its approach to setting the cost of capital to include the ECAPM analysis as one of only two methods over eight years ago.

While not an exhaustive list of examples, the use of ECAPM in these regulatory proceedings demonstrates the methodology is neither new nor novel.

Q. Is the use of Value Line adjusted beta consistent with ECAPM?

A. Yes. Adjusted betas are used in the ECAPM analysis performed by regulatory witnesses referenced above in at least Alaska, Arkansas, Colorado, Maryland, New York, and Oklahoma, as well as cost of capital proceedings in Mississippi. Furthermore, in

[1] National Fuel Gas Distribution Corporation Case 16-G-0257 before the New York Public Service Commission, Order dated April 20, 2017. Page 56 of the Order states, "Staff notes that its CAPM results (8.31% for the traditional CAPM and 8.97% for the zero-beta CAPM) are more in line with its DCF result, indicating that its CAPM is more properly included as a balancing measure to its DCF results." This clearly demonstrates New York State staff use and support of the zero-CAPM model. Further, starting on page 52, the Order states, "As the RD noted, the Commission has repeatedly affirmed certain key elements of the methodology we use in determining the appropriate cost of equity to be included in rates. Those elements consist of the application of Discounted Cash Flow (DCF) and Capital Asset Pricing Model (CAPM) analyses to a representative proxy group of utility companies; the use of a two-stage DCF computation with inputs derived from Value Line; the basing of CAPM results on an average of the outcome from standard and zero-beta models with a risk-free rate based on Treasury bonds, market risk premium provided by Merrill Lynch's Quantitative Profiles, and betas taken from Value Line; and our use of a 2/3 – 1/3 weighting of the DCF and CAPM results, respectively." This also clearly demonstrates the New York State Commission had repeatedly affirmed the use of zero-beta CAPM.

[2] Docket No. 30011-97-GR-17, pre-filed direct testimony of Anthony J. Ornelas (May 1, 2018), pages 52-53.

Dr. Morin's book, *The New Regulatory Finance*, at page 191, he explicitly states the use of an adjusted beta is necessary and that suggestions to the contrary are erroneous. He wrote:

> Some have argued that the use of the ECAPM is inconsistent with the use of adjusted betas, such as those supplied by Value Line and Bloomberg. This is because the reason for using the ECAPM is to allow for the tendency of betas to regress toward the mean value of 1.00 over time, and, since Value Line betas are already adjusted for such trend, an ECAPM analysis results in double-counting. *This argument is erroneous.* Fundamentally, the ECAPM is not an adjustment, increase or decrease, in beta. This is obvious from the fact that the expected return on high beta securities is actually lower than that produced by the CAPM estimate. The ECAPM is a formal recognition that the observed risk-return tradeoff is flatter than predicted by the CAPM based on myriad empirical evidence. The ECAPM and the use of adjusted betas comprised two separate features of asset pricing. Even if a company's beta is estimated accurately, the CAPM still understates the return for low-beta stocks. Even if the ECAPM is used, the return for low-beta securities is understated if the betas are understated.…*Both adjustments are necessary.* [Emphasis added.]

Further, Value Line clearly discloses in Exhibit A-131 (TAW-12) that the Value Line calculation for beta uses historical data, and the adjustment prescribed by Marshall Blume *does not incorporate the effects captured in ECAPM*. The use of Value Line adjusted betas is, therefore, very much consistent with the application of ECAPM.

b. <u>Projected Risk Premium Analysis</u>

Q. Please describe the risk premium analysis that was performed.

A. Investors can choose to invest in either debt or equity in a company. Debt is subject to less risk as it receives a priority claim on assets in bankruptcy relative to equity. Further, interest payments, unlike dividends paid on equity, are mandatory and cannot be deferred. Investors in equity securities, therefore, demand a premium relative to the return paid on the debt. The risk premium analysis estimates the required rate of return on equity by estimating the future yield of utility bonds and then adding the estimated risk premium.

Q. Please describe how the future utility bond yield was calculated.

A. To determine the future yield of utility bonds: (i) the risk-free rate; and (ii) the bond credit spread over United States Treasury Bonds were added together. The applied risk-free rate in the Projected Risk Premium Analysis is the projected long-term government bond return of 4.73% discussed earlier. The estimated bond yield was estimated for each of the bond rating spreads from A to BBB by adding the applicable corporate spreads that have been observed in the market. Exhibit A-14 (TAW-1), Schedule D-5, page 8, column (i), shows that gas utility common stocks have an average historical risk premium of 4.15% (line 72) over the yields of A-rated utility bonds. This premium was added to the estimated bond yields to arrive a range of cost of equity estimates.

Q. What is the result of the risk premium analysis?

A. The Projected Risk Premium Analysis calculates the average ROE is 10.62% and ranges from 10.24% to 11.18%. The results are shown in Exhibit A-14 (TAW-1), Schedule D-5, page 4.

Q. Is this risk premium level and methodology reasonable?

A. Yes, in fact an article published by the Federal Reserve, Exhibit A-129 (TAW-10), page 2, indicates that equity risk premiums in environments with heightened Federal Reserve action are much higher than normal, which renders the application of historical data without additional careful consideration less reliable. In fact, Staff acknowledged this fact in Case No. U-20479 (SEMCO Energy Gas Company's general rate case), noting, "the fact that in low interest rate environments the risk premium tends to be higher than usual.

Although this is not traditionally a factor in Staff's methodology, the data backs this methodology."[1]

c. Discounted Cash Flow Analysis

Q. Briefly describe the DCF model.

A. The DCF model, which is a type of income model, was developed by John Burr Williams and elaborated upon by Myron J. Gordon and Eli Shapiro. It was initially employed as a method of valuing the price of common stock by discounting future cash flows by the cost of capital. In its simplest form, this model can be used to estimate the required cost of equity capital for a dividend paying stock with an assumed constant expected growth rate to perpetuity. This is generally projected as follows:

Equation (6): $K_e = (D_1 / P_0) + g + F$

Where:

D_1 = D_0 x (1 + g);
K_e = annual required cost of equity capital;
D_0 = current annual dividend;
D_1 = annual dividend at the end of the first year;
P_0 = current stock price;
g = expected growth rate; and
F = flotation cost adjustment.

This application of the model is displayed on Exhibit A-14 (TAW-1), Schedule D-5, page 5.

Q. What is the theoretical basis underlying the DCF model?

A. The DCF model is based upon an analysis of publicly traded common stock. The DCF theory is based on the premise that an investor who agrees to purchase common stock at a given market price is purchasing the rights to an income stream. That income stream

[1] Direct Testimony of Joseph E. Ufolla, MPSC Case No. U-20479 (September 27, 2019), page 36.

includes the present and anticipated earnings, the portion of those earnings that are currently and prospectively being paid to investors in the form of dividends, and the proceeds of capital appreciation derived from the ultimate sale of the stock at some future market price.

Implicit in the investor's decision to buy is the assumption that the investor considers the magnitude of that income stream. This includes the rate at which those dividends are expected to grow and the expected future selling price of the stock. The investor also considers the quality or risk of that income stream; that is, the likelihood that expectations will, in fact, be realized.

Based upon all these considerations, the investor agrees to pay a given market price for the stock at a given moment in time. Presumably, that market price represents the present value of that anticipated income stream, including dividend and price appreciation, at some discounted rate. This can be expressed as follows:

Equation (7): $P_0 = D_1/(1+K_e)^1 + D_2/(1+K_e)^2 + \ldots +D_n/(1+K_e)^n + P_n/(1+K_e)^n$

Here, the value of the future anticipated stock price (P_n) and dividends (D_1, D_2,….D_n) are discounted based upon the perceived risk of the investment (K_e). Note, however, that even the future stock price (P_n) becomes a function of anticipated dividend appreciation so that, ultimately, the price of the stock today is a function of the present value of growth of the dividend stream to infinity.

The standard annual form of the DCF model presented in Equation (7) above can be referred to as the dividend growth model. It is equal to the expected dividend yield (D_1/P_0) plus the expected rate of growth in dividends (g) plus the flotation cost adjustment (F). The model assumes an annual dividend payment and that dividends, earnings, book value, and price per share grow at the same constant annual rate over time.

Q. Please explain how dividend yield was calculated.

A. In theory, the DCF method calls for the "spot dividend yield" that is anticipated by investors at the time the required cost of equity capital is determined. Consequently, the theoretical yield would be calculated by dividing the expected annual dividend by the most current stock price. However, spot stock prices are subject to short-term market fluctuations, and an average price is more reliable and more typically applied. As a result, an average of 30 daily closing stock prices, through September 30, 2023, was used. For each of the proxy companies, the average closing stock price for the period identified above was first determined. This provided an estimate of P_0. Then, the latest annual dividend amount was obtained. The annualized dividend was then divided by the average stock price (P_0) to determine the current dividend yield. The annualized dividend was determined by multiplying the latest quarterly dividend payment amount by four. Next, the current dividend yield was adjusted by multiplying by one plus the growth rate to obtain the expected dividend yield. The expected dividend yield is based on the expected dividend at the end of the first year (D_1) versus the current dividend (D_0). This process was repeated for each of the proxy companies. The stock average prices, dividend amounts, and dividend yields are shown on Exhibit A-14 (TAW-1), Schedule D-5, page 5.

Q. How was the growth rate for the DCF calculations determined?

A. One of the difficult steps in applying the DCF model is determining the appropriate growth rate. The DCF analysis should utilize, whenever possible, a single "long-term" (i.e., perpetual) *dividend* growth rate of the company required by the investors who own the company's stock. However, analysts do not typically provide long-term growth for dividends and, therefore, analyst projections for dividends over the next three years were used to estimate dividend growth.

Q. Why was dividend growth instead of earnings growth applied as an input to your analysis?

A. The use of dividend growth is consistent with the fundamental basis of the model, as validated by the original paper, "Capital Equipment Analysis" from Gordon and Shapiro.

This paper is included as Exhibit A-132 (TAW-13), and page 5 of the exhibit makes very clear the intent of the original authors:

> Translated, this means that the rate of profit at which a share of common stock is selling is equal to the current dividend, divided by the current price (the dividend yield), plus *the rate at which the* ***dividend*** *is expected to grow*. [Emphasis added.]

Q. What were the results of the DCF cost of equity analyses for the proxy companies?

A. Exhibit A-14 (TAW-1), Schedule D-5, page 5, shows the results for the Company's group of proxy companies. Proxy group company returns for the Analyst Consensus DCF ROE have a large range from 6.92% to 13.12% with an average return of 10.22%.

Q. Does the result of the DCF analysis fully reflect the cost of equity required for utilities?

A. No, it does not. The DCF is highly reliant upon growth estimates and provides a mechanical application of the DCF that, when taken alone, delivers results that are less reliable and does not produce a risk-appropriate ROE, as required by *Hope* and *Bluefield*. The DCF results can be compared against the CAPM, ECAPM and Risk Premium analyses, and can be viewed as a low end of the resulting spectrum of estimates.

This highlights why regulators such as the Federal Energy Regulatory Commission have had concern with overreliance on the DCF model. The average output of the DCF analysis would not provide sufficient risk premium to fairly compensate investors for the risks associated with owning the stock, particularly because equity owners have the lowest claim to Company assets and income. Because the resulting average of the DCF clearly underestimates the required ROE, the Company's ROE recommendation considers the full range of results provided by the CAPM, ECAPM, DCF, Risk Premium, and Comparable Earnings analyses.

d. Comparable Earnings Analysis

Q. Briefly describe the comparable earnings analysis method.

A. Under this method, projected ROEs for the proxy group were analyzed. Earned ROEs for the proxy group are based on earnings per share and book value per share from Value Line. This information is readily available to investors. The actual results from this method are important in understanding the projected market expectations for the group. Exhibit A-14 (TAW-1), Schedule D-5, page 6, shows the results for the group of proxy companies by year for the period 2026 through 2028. The average projected earned ROE for the proxy group is 10.22% and ranges from a minimum of 8.18% to a maximum of 14.05%.

Q. Why was this method included as part of the ROE analyses?

A. The earnings of a regulated utility are driven to a large extent by the equity book value since most utilities are authorized an earning level based on the book value of equity. As indicated above, the comparable earnings analysis calculates an ROE for the proxy group based on the ratio of earnings per share to projected book value per share using information that is available to investors. This is the same as the cost of equity for a regulated utility and provides a reasonable proxy of analyst and investor expectations for a regulated utility return. Given that earnings in any single year can vary from the authorized ROE, results for multiple years need to be kept in mind while determining the cost of equity capital using this method.

Q. Has the Commission previously commented on the use of the comparable earnings analysis?

A. Yes. In Case No. U-16794, the Commission specifically considered and gave weight to use of the ROE calculated using Value Line book value and earnings.

Q. Has any other jurisdiction given weight to the comparable earnings analysis?

A. Yes. Not only have they given weight to the analysis, the Virginia State Corporation Commission ("VSCC") is required by statute (Virginia Code, section 56-585.1.A.2.a) to consider the earned returns on book value of gas utilities in the region, which establish lower and upper boundaries for the allowed ROE.[1]

Q. Does this conclude your direct testimony?

A. Yes.

---

[1] In orders issued on November 7, 2018, and November 30, 2011, in Case Nos. PUR-2018-00048 and PUE-2011-00037, for example, the VSCC established the allowed ROE for Appalachian Power Company based on the earned returns on book value for a peer group of other gas utilities.